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EPA

Environmental Regulations and the Electric Utility Industry

An Integrated Overview

I. INTRODUCTION & FINDINGS

II. ENVIRONMENTAL REGULATIONS

III. CASE STUDIES

IV. GENERATING UNIT EFFECTS

V. REGIONAL EFFECTS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

APR 25 1983

OFFICE OF
POLICY AND RESOURCE MANAGEMENT

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APR 28 1983
AIR & HAZARDOUS MATERIALS DIV.

Alexandra B. Smith, Director
Air & Waste Management Division
Region X
1200 6th Avenue
Seattle, WA 98101

Dear Mr. Smith:

We are pleased to send you a copy of Environmental Regulations and the Electric Utility Industry--An Integrated Overview. This study, prepared by Temple, Barker, and Sloane, Inc. for EPA, assesses the cumulative economic and financial impacts of EPA's regulations on the electric utility industry.

Electric utilities and their customers have borne a major burden for protecting and improving the quality of our national environment. In 1980 utilities spent over $8.4 billion to comply with EPA's air regulations as well as those governing water and solid waste. This translated into a charge of $2.36 for pollution control on the average residential customer's $35.94 monthly bill. These costs were incurred during a period when rapidly escalating fuel and construction expenses led to major increases in the price of electricity and, indirectly, to a marked decline in electric utilities' financial condition, as evidenced by wholesale declines in bond ratings and by stock prices well below their book values.

This study has four major components:

- A "national" analysis of total utility industry expenditures for pollution control.

- A unit-by-unit examination, drawing on an extensive data base, of environmental compliance strategies, costs, and plans as reported by utilities for over 1,600 generating units. The findings are presented in "unit-category" and regional analyses.

ENVIRONMENTAL REGULATIONS AND THE ELECTRIC UTILITY INDUSTRY

AN INTEGRATED OVERVIEW

FINAL REPORT PREPARED FOR

U. S. ENVIRONMENTAL PROTECTION AGENCY

OFFICE OF POLICY ANALYSIS

ENERGY POLICY DIVISION

PREPARED BY

TEMPLE, BARKER & SLOANE, INC.

- A set of case studies intended to address the issue of indirect costs and uncover some of the subtle influences of environmental requirements on utility decisionmaking.

- A description of the environmental regulations which affect electric utilities.

Sincerely,

Joseph A. Cannon

Joseph A. Cannon
Associate Administrator
for Policy and Resource Management

PREFACE

The information in this document has been funded wholly or in part by the United States Environmental Protection Agency (EPA) under assistance agreements 68-01-5845 and 68-01-5771 to Temple, Barker & Sloane, Inc. (TBS), 33 Hayden Avenue, Lexington, Massachusetts 02173. It has been subject to the Agency's peer and administrative review, and it has been approved for publication as an EPA document. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

The report incorporates modifications--reflecting the reviews and comments of EPA and others--to the draft report issued by EPA under the same title in July 1981. The basic findings presented in the draft report have not changed.

TBS wishes to express its gratitude to the many organizations and individuals who contributed to this study.

If you have any questions regarding this study, please contact the EPA project officer, Rob Brenner, at (202) 382-2772.

CONTENTS

CONTENTS
(continued)

CONTENTS
(continued)

CONTENTS
(continued)

LIST OF TABLES

LIST OF TABLES
(continued)

LIST OF TABLES
(continued)

LIST OF TABLES
(continued)

LIST OF TABLES
(continued)

LIST OF TABLES
(continued)

LIST OF TABLES
(continued)

LIST OF FIGURES

LIST OF FIGURES
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LIST OF FIGURES
(continued)

LIST OF EXHIBITS

LIST OF EXHIBITS
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LIST OF EXHIBITS
(continued)

TOPICAL GUIDE TO THE REPORT

This topical guide, a cross-referencing aid to the large amount of data in the report, is organized by major topics. Those topics are:

- Acts and Regulations
- Capacity Planning
- Cost-Effectiveness Analysis
- Effects of Pollution Control Strategies on Financial Profile
- Electric Utility Baseline Operations
- Fuel Choices
- Pollutants and Discharges
- Pollution Control Strategies
- Research Methodology Used

ACTS AND REGULATIONS

Clean Air Act, and regulations and standards implementing the Act

CAPACITY PLANNING

Planning process within utility companies

National capacity planning

Regional capacity planning

EFFECTS OF POLLUTION CONTROL STRATEGIES ON FINANCIAL PROFILE

Unit category

Baseline projection

Base case scenario

Noncoal alternatives

POLLUTANTS AND DISCHARGES

Air pollutants

Water pollutants

Solid and hazardous wastes

POLLUTION CONTROL STRATEGIES

Pollution control equipment

Cost of technology

<u>Unit category analysis</u>

- Development of Energy Database: I-3, <u>IV-12</u>, IV-26, A-1-3
- Definition of unit categories: <u>IV-12</u>
- Identification of strategies and costs: <u>IV-12</u>

<u>Regional analysis</u>

- Selection of regions: <u>V-5</u>, Figure V-1
- Development of baseline costs: <u>V-5</u>
- Development of pollution control costs: <u>V-7</u>

<u>National analysis</u>

- Overview: <u>VI-11-12</u>, Appendix B
- Determination of applicable regulations: <u>VI-42-55</u>
- Development of financial assumptions: <u>VI-28-34</u>, Appendices B and C
- Coverage of strategies and costs: VI-42-55

I. INTRODUCTION & FINDINGS

CHAPTER I

INTRODUCTION AND KEY FINDINGS

CONTENTS

I. INTRODUCTION AND KEY FINDINGS

INTRODUCTION

This study by Temple, Barker & Sloane, Inc. (TBS), for the Energy Policy Division of the U.S. Environmental Protection Agency (EPA), updates and, perhaps more important, broadens and deepens the scope of a 1976 analysis of the cumulative financial and economic effects of environmental regulations on the U.S. electric utility industry.[1]

The 1976 report, also prepared by TBS for EPA, anticipated in part the fundamental shifts in the industry's fuel sources, the changing patterns of demand, and the strained financial conditions currently affecting the industry. Nonetheless, a plethora of changes--in environmental and energy regulations; in technology; in construction and fuel costs; and in demand growth--led EPA to ask TBS to update that report.

Guide to the Study

The current report is organized in six chapters. Following Chapter I, and to provide a context for the analysis in later chapters, Chapter II presents an overview of the environmental regulations affecting electric utilities. This overview is intended as a summary synthesis of regulations. Its need stems from the complexity of the regulations, which in turn stems from legislative and administrative attempts to meet multiple environmental objectives in a manner that is flexible and applicable to a host of specific situations. A consequence of the complexity is that few people have an overview of the scope and impact of the regulations. This report is intended to provide that perspective.

Chapter III explores the influences of environmental regulations on management decision making within utilities by

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[1]Temple, Barker & Sloane, Inc., <u>Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utility Industry</u>, May 1976.

reporting the findings of six case studies conducted by TBS for this study. This exploration adds a first new dimension to the scope of the 1976 analysis. As is highlighted in the following paragraphs, two key issues are addressed in this chapter. The first is why companies have selected particular compliance strategies in the past and whether their actions in the future are likely to conform to the prospective engineering assumptions used in this study's analysis. Actions by regulatory commissions that lead to inadequate rates of return and to financing constraints, for example, can influence choices of compliance strategies in ways not captured in engineering economic studies.

A second issue concerns costs that may not be reflected adequately either in utilities' reports of historic and anticipated costs or in engineering analyses. There is the question, for example, whether environmental regulations cause uncertainties and delays in planning, permitting, construction, and operating activities that have costs that are real and significant, but that are often unrecognized and rarely quantified. As another example, there is the question whether environmental regulations will lead not only to the easily identifiable use of expensive fuels and pollution control equipment, but also to the less easily observed costs associated with the construction of smaller and less efficient units, the location of units at sites remote from customers, or the inability to expand capacity in parallel with demand at any reasonable cost.

In an attempt to explore the issue of real but indirect costs and to illuminate some of the subtle influences on utility decision making, TBS conducted a series of interviews with company executives and technical staff. These were supplemented by interviews with a variety of environmental and other regulatory officials in various states and regions and by discussions with other knowledgeable individuals in other organizations. This research identified the qualitative consequences of environmental regulations that are not easily captured in quantitative terms.

Another new dimension in the current study is a detailed quantitative investigation into what actions the industry actually has taken and is currently planning to take to meet environmental requirements. This analysis draws on an extensive database, developed by TBS for EPA, of compliance strategies, costs, and plans as reported by utilities for 2,277 generating units, representing 96 percent of the industry's total fossil-fuel generating capacity. This database provides a solid empirical foundation for many of the assumptions concerning the average costs and prevalence of alternative strategies for complying with environmental regulations.

Perhaps even more important, the database supports a new kind of analysis appearing in Chapters IV and V--namely an investigation into the differences in total pollution control costs among units. This analysis of the industry's unit-by-unit pollution control actions and plans has two major parts. The first, called the "unit-category" analysis, focuses on the differences in costs across units coming into service at different times--and therefore subject to different environmental regulations--and burning different types of fuels--i.e., coal, oil, gas, or nuclear. This discussion appears in Chapter IV.

The second analysis of the industry's reported actions and plans, called the "regional" analysis, appears in Chapter V and focuses on the differences in costs across geographic regions. This analysis illuminates the differences in pollution control costs per kilowatt-hour (kWh) that arise from regional variations in existing air and water quality pollution control requirements, mix of generating capacity, availability and cost of low-sulfur fuels, and other factors. To the extent that utilities in a region are all affected by and respond to environmental requirements similarly, this analysis also indicates the differences among regions in the increases in consumer bills associated with pollution control strategies.

The earlier study focused essentially on the financial and economic implications of engineering analyses concerning the average construction and operating costs of various methods for controlling specific pollutants and concerning the extent to which each method would be used to comply with regulatory requirements. The sixth and last chapter of the current study, called the "national" analysis, again uses this methodology. The analysis reflects new environmental requirements, updated engineering estimates, and the latest available information concerning the industry's present condition and future trends. A 25-year time span is evaluated using TBS's computerized financial model of the industry.

Each chapter in this report is preceded by a table of contents to aid the reader in sorting through the vast amount of information covered in the study. In addition, Chapters III through VI contain introductory sections summarizing the key findings that are explored more fully in subsequent sections.

Four appendices follow the chapters. Appendix A briefly describes the Energy Database; Appendix B presents an overview of PTm(Electric Utilities); Appendix C discusses financial procedures used by the electric utility industry to account for capital expenditures. Appendix D discusses determinants of coal prices in the absence of environmental regulations and within the context of environmental regulations.

Research Methodology and Assumptions

The research methodology employed in this study is based on two quantitative tools and one qualitative tool.

The Policy Testing model of the electric utility industry, PTm(Electric Utilities), is one of a series of computer models developed by TBS to project the economic and financial implications of alternative policy options in the form of growth rates, mix of generating capacity additions, financial strategies, regulatory actions, taxation policies, economic conditions, and other influences.

The second quantitative tool, the Energy Database, is a computerized information system developed by TBS for EPA. The information was obtained from 1979 Federal Energy Regulatory Commission's Form 67s submitted by utilities to the Energy Information Administration of the Department of Energy. Included in the database are all fossil-fueled steam-electric units with a capacity of 25 megawatts (MW) or greater for which Form 67 data were available. The database provides a comprehensive foundation for the analysis of utility plant operations.

Finally, qualitative case studies of utilities explore the influences of environmental regulations on management decision making within utilities.

Although this study focuses on federal environmental regulations, the only actual cost data available reflect total pollution control costs. To the extent, therefore, that state or local requirements for air, water, or solid waste pollution control exist in the absence of federal regulations or exceed the minimum standards necessary for compliance with federal regulations, the costs identified in this analysis are not entirely attributable to federal requirements. To the extent that utilities undertake certain expenditures for reasons other than environmental compliance--for example, installing cooling towers for economic reasons--the costs identified in this analysis may have joint attributes. Where possible, the discussion identifies contributing components of costs, particularly at the unit-category level in Chapter IV.

KEY FINDINGS

During the 1970s, environmental regulations covering air, water, and solid wastes were strengthened substantially. During the same period, rapidly escalating fuel and construction costs have led to major increases in the price of electricity and, indirectly, to a marked decline in electric utilities' financial condition, as evidenced by wholesale declines in bond ratings and by stock prices well below their book values. In these circumstances, the uncertainties and costs associated with environmental regulations have come to be increasingly important to utility plans and operations.

Electric utilities are major contributors to total pollutant loadings in the environment. In 1979 pollution controls at electric utility powerplants were responsible for removing 42 percent of total potential SO_2 emissions, or 12.2 million tons, and 98 percent of total potential particulate emissions, or 45 million tons. Environmental controls on coal units contributed the dominant share of pollutants removed. Refer to page I-22 for a more detailed discussion of pollutant removals by unit type.

Nationwide in 1980, consumer charges--the average cost of electrical energy per kilowatt-hour--attributable to compliance with pollution control requirements averaged 4.0 mills per kWh (expressed in 1982 dollars). This represents an increase of 9.3 percent over base consumer charges of 42.7 mills per kWh that would be incurred in the absence of compliance costs. In 1999, consumer charges for pollution control strategies that respond to regulations in place during the period 1971-1999 are expected to average 5.0 mills per kWh, or 9.8 percent over base costs of 51.2 mills per kWh (expressed in 1982 dollars).

The expense and difficulty of achieving compliance with environmental regulations vary greatly across regions of the country, electric utility companies, and individual generating units. Some utilities have stated that environmental regulations constitute a major obstacle, especially to meeting future demand for electricity. Others have expressed no great concern. The primary influencing factors appear to be ambient air quality near powerplants, the types of fuels consumed, the local availability of low-sulfur coal, and the stringency of state implementation plans (SIPs).

To date, utilities have complied with the most costly regulations--those related to sulfur dioxide (SO_2)--primarily by increasing the quality of their fuels rather than installing equipment. In 1979, the fuel premium accounted for nearly 65 percent of the national average annualized cost of 3.88 mills per kWh for pollution control at fossil-fueled units (expressed in 1979 dollars). The premium for low-sulfur oil accounted for nearly 90 percent of total pollution control costs at oil-fired units.

Past and future strategies for compliance with SO_2 and total suspended particulate (TSP) regulations have reflected and will reflect increasingly stringent standards and result in rising capital costs for pollution control equipment. For example, for coal-fired units in service before 1972, the capital portion of pollution control costs is 0.76 mills per kWh; for units coming into service in the 1980-1984 period that are subject to new source performance standards (NSPS I) for air, the capital costs contribute an average of 5.12 mills per kWh (expressed in 1979 dollars).

During the period 1980-1999, pollution control equipment will add $87.3 billion, or 8.4 percent, to the industry's plant in-service base of $1,041.5 billion, and will add $68.2 billion, or 7.9 percent, to the industry's baseline external financing requirements of $857.6 billion (expressed in 1982 dollars). The magnitude of this financing need, combined with the financial difficulties already confronting the industry, could create significant problems for individual utilities.

In 1979, the average cost of reducing SO_2 emissions was $461 per ton. Among coal units, reducing SO_2 emissions was on average nearly twice as expensive using scrubbers as it was using low-sulfur coal. The national average cost of reducing TSP emissions was $22 per ton. This average cost is dominated by the low average cost of removing very large quantities of TSP at coal-fired units. Removal costs for future, NSPS II, units are dominated by scrubbers and are projected to be significantly greater than costs at existing units. Refer to page I-22 for more detailed information on removal costs by unit type.

When future growth in demand requires new capacity to be added, coal-fired powerplants will be the most likely choice. However, the large capital requirements associated with building plants that meet the revised new source performance standards (NSPS II) and the possible siting constraints imposed by a lack of increments in attainment areas and the cost or unavailability of offsets in nonattainment areas will hamper some utilities in their attempts to meet growth in the demand for electricity.

The following sections present a summary of key findings in each area of analysis. They conform to the organization of the full report, beginning with an overview of environmental regulations affecting the electric utility industry and ending with a discussion of national effects of those regulations. The reader is cautioned that, as this is a summary, there is no discussion of the methodological approach, assumptions, and uncertainties that are contained in each full chapter.

An Overview of Environmental Regulations Affecting Electric Utilities

Environmental regulations applicable to electric utilities are extensive, complex, and evolving over time. The regulations are extensive because the electric utility industry is an important source of air and water pollution and a major generator of solid wastes. They are complex and evolving because a multiplicity of interests, objectives, and technical and scientific developments have influenced and are influencing their development.

Although the industry traditionally has had its own programs for controlling air, water, and solid waste pollution, further requirements pertaining to each type of pollutant have evolved separately through legislative, regulatory, and legal processes at the local, state, and federal levels. The specific requirements often vary from plant to plant, sometimes even from unit to unit in a plant, depending on a variety of considerations, including a generating unit's age, location, fuel type, and technical configuration. In addition to the air, water, and solid waste regulations that are assessed in this report, the industry has to comply with other environmentally related regulations, such as noise control and the protection of endangered species and coastal zones.

In some geographic areas, it is arguable that regulations affecting local utilities would be just as strict as they are now even in the total absence of federal regulations. In some other geographic areas, it is arguable that federal requirements are the sole driving force behind some existing regulations. However, because of the complexity of the interactions among regulations, the appropriateness of these arguments cannot be determined readily. Further, responsibility for the detailed specification and enforcement of particular regulations is often delegated from one level of government to another. Thus, this study does not attempt to partition environmental requirements into those attributable to federal, state, and local initiatives.

Electric utility air pollution has been a major focus of regulation because of the large total quantity of pollutants emitted by the industry as a whole and because of the large amounts of certain pollutants emitted by some plants. The regulated pollutants are all combustion by-products. The combustion of natural gas, coal, and oil forms nitrogen oxides (NO_x); sulfur and sulfur compounds contained as impurities in coal and oil become SO_2; and other solid impurities in coal and oil emerge as particulate matter (fly ash). Despite a shift to lower sulfur fuels, the installation of considerable amounts of pollution control equipment, and changes in boiler design and operation already accomplished by 1979, the industry in that year still emitted about 17 million tons of SO_2, about 7 million tons of NO , and slightly less than 1 million tons of TSP. In the case of SO_2, the average electric utility plant has uncontrolled emissions substantially larger than other industrial sources.

During the late 1960s, Congress concluded that previous state and federal initiatives to address the problems of air pollution, including the Clean Air Act of 1964, were inadequate and, in the 1970s, passed two major pieces of legislation. The Clean Air Act Amendments of 1970 (generally known as the Clean Air Act or the Act) established a new legal framework to protect and enhance air quality and to provide oversight in the implementation of air quality control programs. The Act stated that EPA should establish nationwide national ambient air quality standards (NAAQS) and industry-specific new source performance standards. Individual states were given responsibility for the actual implementation of the Clean Air Act's provisions.

In 1977, further amendments extended the deadline for the attainment of all primary (health-related) standards. States were to prepare and submit to EPA, by January 1979, revised implementation plans for all nonattainment areas. The plans were to provide for the implementation of all "reasonably available control measures as expeditiously as practicable" for existing sources and for "reasonable further progress," demonstrated on an annual basis, toward meeting standards. Currently, the Clean Air Act is again under review by Congress.

Water regulations have affected electric utilities less than air regulations. The industry uses water primarily for cooling and, therefore, pollutants in most electric powerplant waste streams tend to be similar and not highly concentrated. However, the volumes of these streams can be great. The industry is the nation's largest industrial user of water, despite the fact that water use by steam electric utilities has decreased dramatically over the past decade. According to the Bureau of the Census, in 1975 steam electric plants used 89 billion gallons of water per day; by the year 2000 it is expected to decrease to 80 billion gallons. Even with continuing declines in usage per plant, electric utilities will account for more than one-third of the nation's total water use over the next two decades and for more than twice as much water use as all other industrial plants combined.

Current regulations to control water pollution were mandated by Congress in the Federal Water Pollution Control Act of 1972 (the Clean Water Act) as amended in 1977. The approach taken by regulations implementing the Clean Water Act differs in important respects from the approach taken by air regulations. Whereas ambient air quality standards drive regulations controlling air pollution, technology standards dominate water pollution control. Consequently, while air regulations have imposed different standards for attainment and nonattainment areas, federal regulations to control water pollution generally have not differentiated among regions of the country. States, of course, can and do impose additional water-quality-related requirements.

The basic mechanism for enforcing the requirements of the Clean Water Act is the national pollution discharge elimination system (NPDES) permit required for all point source discharges into the navigable waters of the United States. NPDES permits incorporate specific pollution control requirements based on effluent limitations guidelines that have been issued periodically by EPA. In practice, the major standards applying to electric utilities have been best practicable control technology (BPT), specifying standards to be met by July 1, 1977; best available technology economically achievable (BAT), specifying standards for toxic pollutants to be met by July 1, 1984; and NSPS, setting requirements for plants commencing construction after a given date (usually the date of proposal of the regulations containing the NSPS).

Until recently, electric utility solid waste disposal practices have received little attention relative to utility air and water pollution practices. Electric utility solid wastes include: by-products of coal combustion and flue gas cleaning such as ash and scrubber sludges; chemical wastes from metal cleaning, from degreasing, and from wastewater and makeup water cleaning; and hazardous substances (notably polychlorinated biphenyls--PCBs) contained in electrical equipment such as transformers. Three factors, however, have focused increasing attention on utility solid wastes: (1) the increasing stringency of air and water pollution regulations that have led to control techniques that themselves generate solid waste; (2) the possibility that some or all of these wastes may be designated as "hazardous" under the Resource Conservation and Recovery Act (RCRA) and therefore will require expensive disposal procedures; and (3) an increasing awareness nationwide of solid waste disposal in the wake of events at Love Canal and elsewhere.

The major federal regulations governing solid waste disposal were mandated by the Resource Conservation and Recovery Act of 1976. Under RCRA, EPA was required to develop an integrated program for managing hazardous and solid wastes. As provided by RCRA, the hazardous waste management aspect of the program would be developed initially by EPA, but authority for implementing it would be delegated subsequently to states with programs equivalent to the federal programs. Programs for managing nonhazardous solid wastes were to be developed by individual states, provided that general minimum guidelines promulgated by EPA are met or exceeded.

Though environmental programs for air, water, and solid waste are distinct in a regulatory context, they come together at individual plants. Air pollutants removed by wet systems to comply with air regulations create waste streams controlled by water regulations, which in turn generate sludges that must be disposed in compliance with solid waste regulations. The overlapping coverages of the regulations for air, water, and solid wastes dictate that electric utilities consider cross-media compliance strategies within the context of unit and plant operations. The quantitative assessment presented in this study is consistent with that approach.

<u>The Effects of Environmental Regulations on Utility Operations and Plans</u>

Environmental regulations affect both the operation of existing utility powerplants and the planning for future capacity additions. Interviews with the case study companies uncovered four major conclusions regarding their compliance activities associated with existing powerplants. First, the expense and difficulty of achieving compliance at existing powerplants varies greatly among utilities and appears to be a function primarily of the ambient air quality near powerplants, the types of fuel consumed, and the stringency of SIPs. Second, as is corroborated by the quantitative unit-level analysis discussed in Chapter IV, utilities have complied with the most costly regulations--those related to SO_2--primarily by increasing the quality of their fuels rather than by installing equipment. Third, utilities fully accept their responsibility to monitor pollutant emissions and report violations accurately to EPA or state environmental agencies. Finally, to reduce capital and operating costs, utilities have usually sought to reduce the stringency of regulations they have to meet through negotiation or litigation.

The TBS interviews also revealed a pervasive concern that financial considerations will become more influential in utility decision making and will hamper the ability and willingness of utilities to meet the capital requirements associated with capacity expansion and pollution control. The full impact of the industry's current weak financial condition has not yet been felt, in part because load growth since 1974 has fallen dramatically. Many utilities have continued the construction of powerplants already under way before the falloff in growth became apparent, but they have been able to pare back other construction programs and lower their long-run financing requirements. However, when future growth in demand requires new capacity to be added, the large capital requirements associated with building new coal-fired powerplants may be an obstacle for financially weak utilities. Perhaps as important, even utilities that have relatively high bond ratings--e.g., those with A bond ratings--will be reluctant to make investments that require the issuance of additional common stock if they expect future earnings to be inadequate. To the extent that environmental regulations contribute to the capital and operating costs of new capacity, both utilities and consumers may attempt to modify environmental requirements in an attempt to lower electricity costs and to avoid reductions in service reliability.

While some case study companies, principally those operating in areas with relatively good ambient air quality, are not greatly concerned with prevention of significant deterioration (PSD) regulations, other companies stated that, even in the absence of financial constraints, existing air environmental regulations will all but eliminate their ability to site coal-fired powerplants in the future. These companies are convinced that existing PSD regulations are unworkable and are actively working to secure passage of legislation to revise them. These utilities believe that PSD increments will be exhausted over time and that utilities will be required to obtain offsets--which may be costly or unavailable at any price. These beliefs are a point of contention with various environmental officials.

To avoid or to mitigate the financial and environmental difficulties associated with siting, building, and operating new coal-fired powerplants, the majority of the case study utilities are actively pursuing other capacity alternatives. For example, some companies are exploring the use of synthetic fuels to supplement or displace oil and natural gas. Utilities also are reconsidering historical standards of reliability with an eye toward lowering such standards and thereby slowing the rate at which new capacity needs to be added. Some of the companies studied are actively considering purchasing power to meet future demand, attempting thereby to export both some environmental and financial problems. Several of the companies are actively exploring greater use of unconventional sources of power such as the sun, the wind, and wood and are currently planning on them to contribute to future electricity supply. However, reflecting the technological uncertainty associated with these sources, these companies have contingency plans that involve more traditional sources of supply such as new coal-fired powerplants.

As an alternative to building new capacity, all the case study companies are evaluating, and some are aggressively pursuing, direct load controls, conservation programs, and new pricing structures such as time-of-day rates. The attractiveness of these alternatives depends on situational factors. Companies that currently have ample capacity tend to prefer not to restrict demand. Other companies facing the prospect of having to build new powerplants may vigorously try to hold down demand, but be unable to find cost-effective ways for doing so.

While environmental considerations may not have been the major factor in shaping the plans of the case study utilities, environmental regulations have presented them with significant challenges. Environmental regulations have increased the lead time for new powerplants and have increased the uncertainty associated with meeting all necessary permitting and licensing requirements.

Technology-forcing regulations also have increased the technological risk perceived by utilities. Some of these regulations require state-of-the-art pollution control equipment that may not perform well enough to achieve compliance and may adversely affect a plant's performance. The utilities interviewed believe that the technology-forcing approach to environmental control is undesirable because it may preclude the use of more certain and cost-effective ways to control pollutants. Utilities strongly prefer to be given performance standards, but be allowed to choose the best method for complying with them. The case study companies also expressed concern that, as new technologies are introduced, environmental standards will change, thereby creating additional uncertainty and higher costs.

Utilities have responded to the challenges presented by environmental regulations in several ways. First, they have made their environmental affairs departments an important element in the utility planning process. These departments are typically responsible for gathering and assessing information on regulatory requirements, costs, and risks and for trying to anticipate changes in environmental regulations. The departments attempt to reduce the potential adverse consequences of uncertainty about regulations by identifying key environmental issues, preparing contingency plans, and attempting to maintain as much flexibility as possible in the utilities' supply plans. Utilities also have supported lobbying efforts to change requirements from a technology-forcing orientation to an approach that focuses on meeting pollutant loading goals. Finally, utilities have initiated research and development activities that have contributed to their ability to meet existing requirements in a cost-effective manner and that develop technical expertise which can be used to support negotiations and, when necessary, litigation.

The Effects of Environmental Regulations on Electric Utility Units

The analysis of the effects of environmental regulations on steam-electric generating units is based on data compiled in the Energy Database from 1979 Form 67 submittals by utilities. The 2,277 units represent approximately 96 percent of the total capacity of fossil-fired steam-electric units reported in DOE's 1979 Inventory of Powerplants.

Distribution of Units by Fuel Type and Age

Coal-fired units account for nearly 60 percent of the capacity of units in the Energy Database (Table I-1). The remaining 40 percent of capacity is relatively evenly distributed among units that burn oil, gas, and oil and gas combined.

Electric utility units are subject to different regulatory requirements depending on their in-service dates. Eighty-six percent of the units in the Energy Database were in service by 1972 (Table I-2). Environmental compliance for these units has consisted of retrofitting pollution control

Table I-1

DISTRIBUTION OF FOSSIL-FUEL UNITS BY FUEL TYPE

Fuel Type	Percent of Units	Percent of Capacity
Coal	47	59
Oil	17	15
Gas	17	13
Gas/Oil	19	13
Total	100	100

Source: Energy Database.

equipment to comply with regulations for existing sources promulgated under the Clean Air and Clean Water Acts. Units that came into service in the 1972-1976 period, representing 9 percent of the units, have also been subject to existing source air and water regulations, but in most cases compliance for these units has consisted of installing original pollution control equipment. Finally, units that have come into service since 1976, representing 5 percent of the units, have as a rule been subject to new source standards under the Clean Air and Clean Water Acts.

Table I-2

DISTRIBUTION OF FOSSIL-FUEL UNITS BY IN-SERVICE YEAR

In-Service Year	Percent of Units	Percent of Capacity
Pre-1972	86	64
1972-1976	9	25
1976-1979	5	11
Total	100	100

Source: Energy Database.

Environmental Compliance Strategies

Strategies for compliance with SO_2 and TSP requirements among coal units reflect increasingly stringent standards. Twenty-three percent of coal capacity that came into service before 1977 either burns coal with less than 0.8 percent sulfur or has flue gas desulfurization (FGD) systems (Table I-3). The proportion of capacity in this category rises dramatically to 73 percent of 1977-1979 capacity and to 98 percent of capacity that is projected to come into service in 1980-1984. This increase reflects primarily the increasing use of scrubbers (FGD systems) from 5 percent of pre-1977 capacity, to 35 percent of 1977-1979 capacity, and to 52 percent of 1980-1984 capacity.

Table I-3

DISTRIBUTION OF COAL CAPACITY
BY REPORTED SO_2 COMPLIANCE STRATEGY

(percent of age-category capacity)

SO_2 Compliance Strategy	In-Service Year		
<0.8% Sulfur Coal	Pre-1977	1977-1979	1980-1984
With FGD	2	22	14
Without FGD	18	38	46
>0.8% Sulfur			
With FGD	3	13	38
Without FGD	77	27	2
Total	100	100	100

Source: Energy Database.

Over 96 percent of the capacity in coal-fired units has TSP collection systems whose removal efficiencies are above 98 percent (Table I-4). Although all coal units attain high levels of TSP removal, the types of equipment in place reflect evolving regulatory requirements. Units that came into service before 1972, for example, often have retrofitted electrostatic precipitators alongside older, less efficient mechanical collectors.

Table I-4

DISTRIBUTION OF COAL CAPACITY BY REPORTED TSP COMPLIANCE STRATEGY

(percent of age-category capacity)

TSP Collection Efficiency	Pre-1977	1977-1979
>98	96	97
96-98	2	2
90-95	1	0
<90	1	1
Total	100	100

Source: Energy Database.

Air pollution control strategies at oil and gas/oil units consist primarily of the use of low-sulfur oil to control SO_2 emissions. Over 60 percent of the capacity in oil-fired units burns oil with less than 1 percent sulfur by weight. A further 30 percent of this capacity burns oil with 1 to 2 percent sulfur, and less than 10 percent uses oil with more than 2 percent sulfur (Table I-5). Only 40 percent of oil and oil/gas capacity has particulate control systems and less than a fourth of these systems have removal efficiencies greater than 98 percent.

Table I-5

DISTRIBUTION OF OIL CAPACITY BY REPORTED SO_2 CONTROL STRATEGY[1]

Fuel Percent Sulfur	Percent of Capacity
<0.9	63
1-1.9	29
>2.0	8

[1]Includes gas/oil units.

Source: Energy Database.

Water pollution controls at steam-electric units are much less elaborate and costly than air pollution controls. Nonetheless, virtually all plants have central treatment facilities to treat a number of relatively low-volume waste streams simultaneously. In addition, some plants have installed ash transport water recirculation systems which are no longer required by federal regulations. Moreover, the use of cooling towers or ponds to control thermal discharges is becoming increasingly prevalent. The share of capacity with cooling systems increases from less than one-third of pre-1972 capacity to two-thirds of 1977-1979 capacity (Table I-6). This shift reflects both environmental requirements and an increasing proportion of units sited in water-constrained areas where recirculating cooling systems are used primarily for economic rather than environmental reasons.

Table I-6

DISTRIBUTION OF FOSSIL-FUEL CAPACITY BY THERMAL CONTROL STRATEGY[1]

(percent of age-category capacity)

	Pre-1972	1972-1976	1977-1979
With cooling tower or pond	26	63	66
Without cooling tower or pond	74	37	33

[1]Totals may not add to 100% due to rounding.

Source: Energy Database.

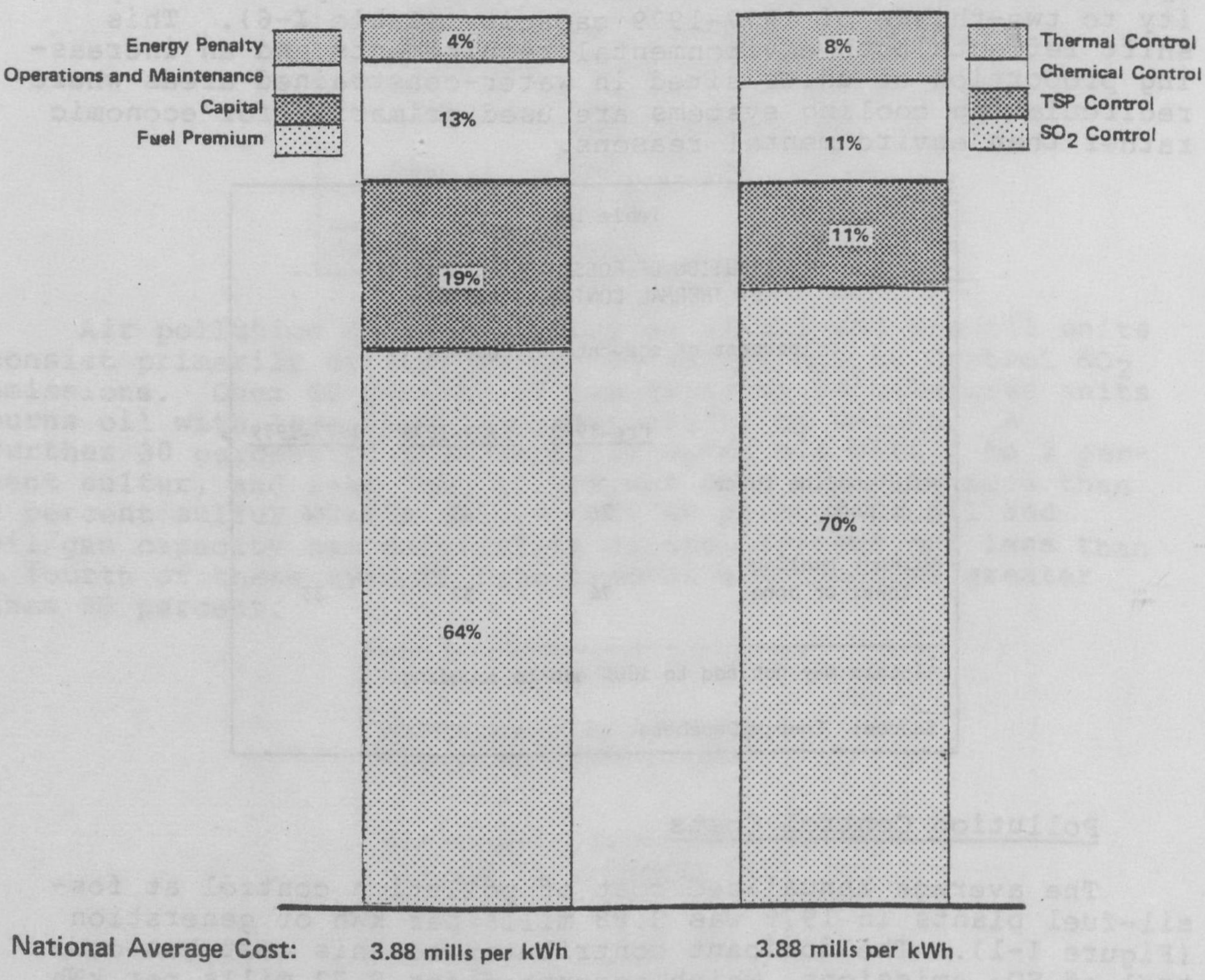
Pollution Control Costs

The average annualized cost of pollution control at fossil-fuel plants in 1979 was 3.88 mills per kWh of generation (Figure I-1). The dominant contributor to this cost was control of SO_2 emissions, which accounted for 2.72 mills per kWh or 70 percent of total pollution control expenditures. The remaining pollution control expenditures were relatively evenly divided among controls for TSP emissions and chemical and thermal discharges. By cost component, the largest single component of pollution control cost was a premium paid by utilities for low-sulfur fuels. This premium accounted for nearly 65 percent of the average cost of pollution control, and contributed more than three times as much as did capital expenditures to pollution control costs.

Figure I—1

COMPONENTS OF 1979 AVERAGE COST OF POLLUTION CONTROL FOR FOSSIL FUEL UNITS

1979 DOLLARS



Source: Energy Database.

Consumption of oil for steam generation resulted in greater pollution control expenditures in 1979 than did consumption of coal or gas because of the premium paid by utilities for low-sulfur oil (Figure I-2). The average 6.86 mills per kWh paid by utilities for low-sulfur oil was more than 3.5 times as great as the low-sulfur coal premium and it exceeded total pollution control expenditures by coal units.

Aside from the low-sulfur fuel premium, in 1979 coal units incurred greater pollution control expenditures than did units burning oil or gas. Coal units incurred average expenditures of 1.85 mills per kWh for pollution control in addition to the fuel premium; oil, gas, and gas/oil units spent 0.5 to 1.0 mills per kWh for capital and nonfuel operating costs. The major reasons for these greater costs incurred by coal units were their expenditures for scrubbers and TSP control systems.

The major trend in pollution control costs is a continuing rise in capital expenditures. Coal plants, which will increasingly dominate fossil-steam capacity, exhibit dramatic increases in pollution control capital costs over time (Figure I-3). Among pre-1972 coal units, capital costs accounted for 1979 pollution control costs of 0.76 mills per kWh. This cost increased by 270 percent to 2.81 mills per kWh for units that were subject to NSPS I regulations. In the future, with higher costs for scrubbers required for all new coal units under NSPS II regulations, capital costs will continue to increase. If eastern utilities choose to burn high-sulfur coal with high-efficiency scrubbers, a decrease in the low-sulfur coal premium may partially offset higher capital costs.

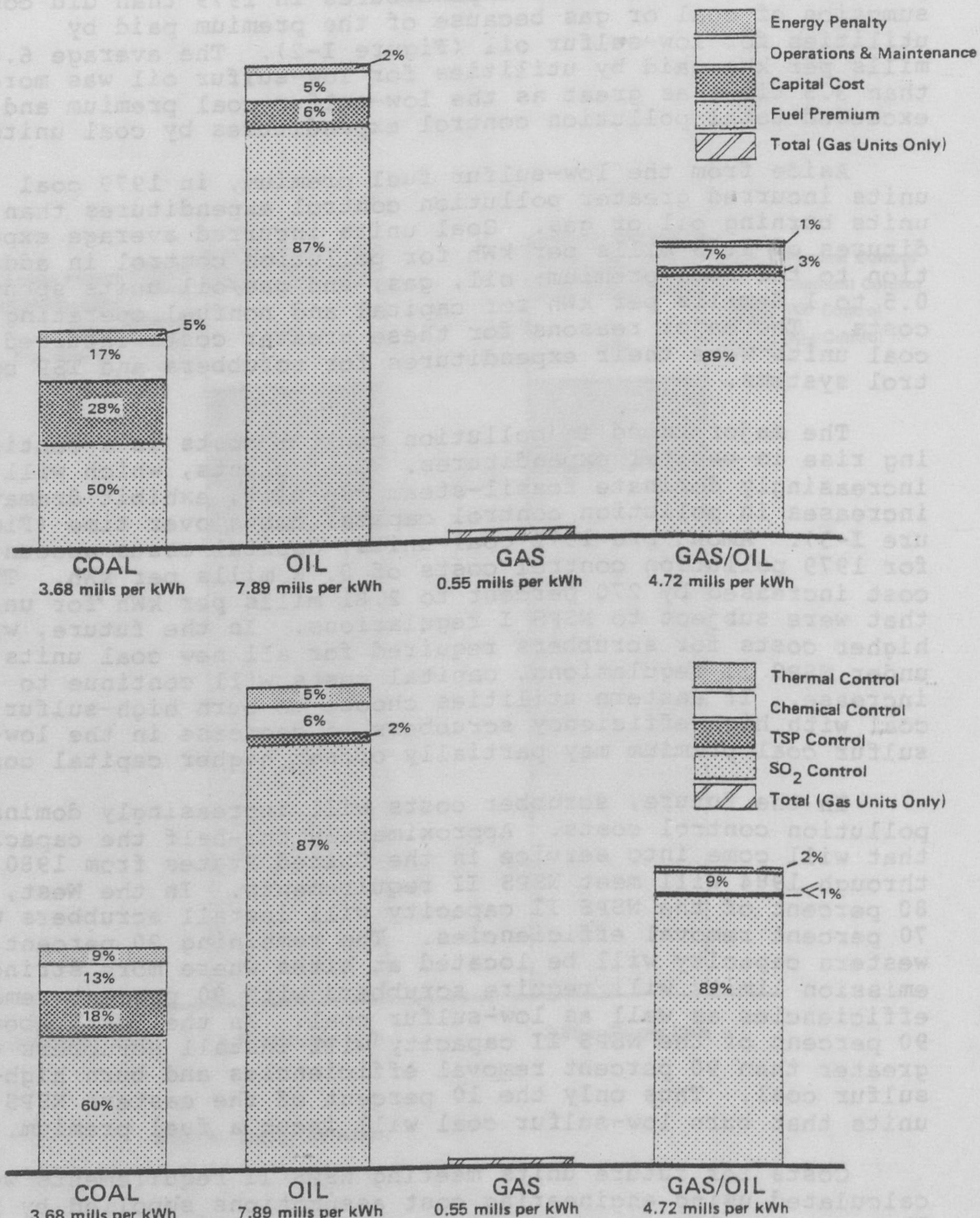
In the future, scrubber costs will increasingly dominate pollution control costs. Approximately one-half the capacity that will come into service in the United States from 1980 through 1984 will meet NSPS II requirements. In the West, 80 percent of the NSPS II capacity will install scrubbers with 70 percent removal efficiencies. The remaining 20 percent of western capacity will be located at sites where more stringent emission limits will require scrubbers with 90 percent removal efficiencies as well as low-sulfur coal. In the East, about 90 percent of the NSPS II capacity will install scrubbers with greater than 90 percent removal efficiencies and burn high-sulfur coal. Thus only the 10 percent of the eastern NSPS II units that burn low-sulfur coal will incur a fuel premium.

Costs for future units meeting NSPS II requirements were calculated using engineering cost assumptions supplied by EPA. These costs will range from 9.4 mills per kWh for western low-sulfur coal units to 13.4 mills per kWh for eastern low-sulfur

Figure I–2

COMPONENTS OF 1979 NATIONAL AVERAGE COST OF POLLUTION CONTROL FOR FOSSIL FUEL UNITS BY FUEL TYPE

1979 DOLLARS

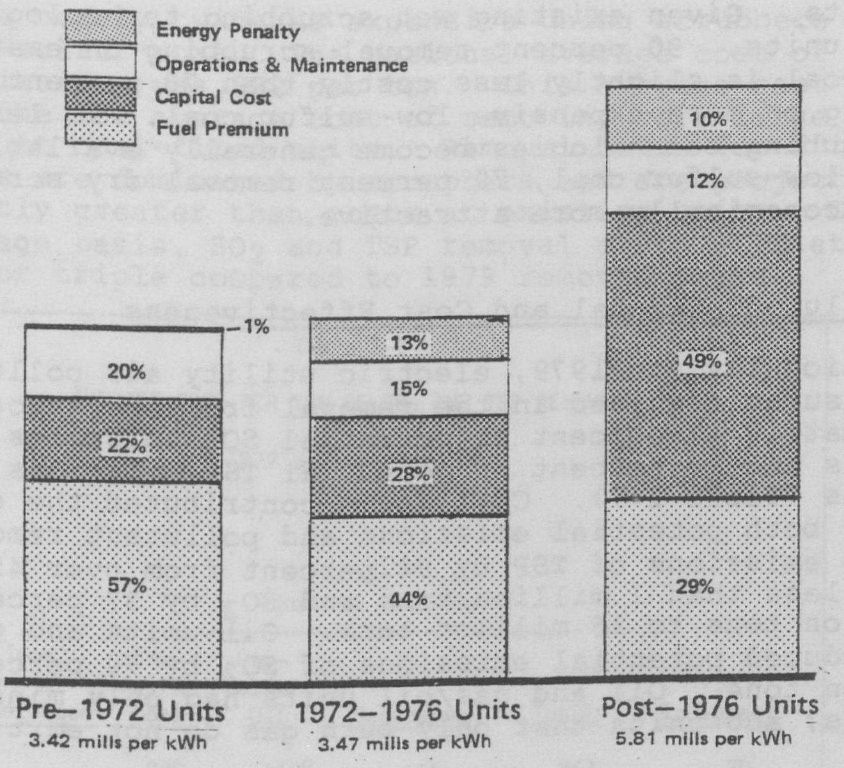


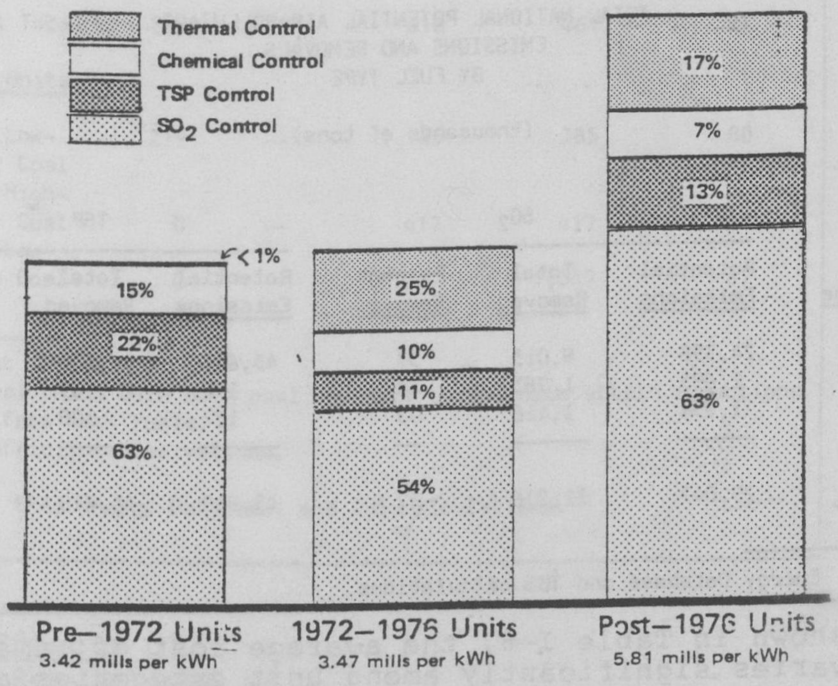
Source: Energy Database; TBS calculations.

Figure I–3

COMPONENTS OF 1979 NATIONAL AVERAGE COST OF POLLUTION FOR COAL UNITS BY AGE CATEGORY

1979 DOLLARS





Source: Energy Database.

coal units. Given existing wet scrubbing technologies for eastern units, 90 percent removal scrubbing on eastern high-sulfur coal is slightly less costly than 70 percent removal scrubbing on more expensive low-sulfur coal. If less costly dry scrubbing technologies become generally available for eastern low-sulfur coal, 70 percent removal dry scrubbing will become economically more attractive.

Pollutant Removal and Cost Effectiveness

Nationally, in 1979, electric utility air pollution control measures resulted in the removal from the atmosphere of approximately 42 percent of potential SO_2 emissions of 29 million tons and 98 percent of potential TSP emissions of 46 million tons (Table I-7). Coal units contributed the dominant share of both potential emissions and pollutant removals, reducing emissions of TSP by 98 percent from over 45 million tons to less than 1 million tons and SO_2 by 37 percent from 24 million tons to 15 million tons. Oil units and gas/oil units reduced potential emissions of SO_2 by 70 percent from 5 million tons. Oil and gas/oil units had only minor TSP emissions, and units that only burn gas do not emit SO_2 or TSP.

Table I-7

TOTAL NATIONAL POTENTIAL AIR POLLUTANT EMISSIONS AND REMOVALS BY FUEL TYPE

(thousands of tons)

	SO_2			TSP		
Fuel Type	Potential Emissions	Total Removed	Percent Removed	Potential Emissions	Total Removed	Percent Removed
Coal	24,398	9,015	37	45,651	44,775	98
Oil	2,695	1,783	68	170	143	84
Gas/Oil	1,954	1,418	73	127	100	79
Total	29,047	12,216	42	45,948	45,018	98

Source: Energy Database and TBS calculations.

As shown in Table I-8, the average cost of removing pollutants varies significantly among unit categories and pollutants. In 1979, the average cost of reducing SO_2 emissions was $461 per ton. The cost of reducing these emissions was nearly three times as great at oil-fired units as it was at coal-fired units. Among coal units, reducing SO_2 emissions was on average nearly twice as expensive using scrubbers as it was using low-sulfur coal. The national average cost of reducing TSP emissions was $22 per ton. This average cost is dominated by the low average cost of removing very large quantities of TSP at coal-fired units. Removal costs for future, NSPS II, units are dominated by scrubbers and are projected to be significantly greater than costs at existing units. On a weighted average basis, SO_2 and TSP removal costs will at least double or triple compared to 1979 removal costs.

Table I-8

AVERAGE COST PER TON OF SO_2 AND TSP REMOVAL

(1979 dollars per ton)

Fuel Type	SO_2 Removal Strategy				
1979 Generation	Low-Sulfur Coal	Low-Sulfur Oil	Scrubbers	Total	TSP Equipment
Coal	229	412[a]	418	263	20
Oil	N/A	737	N/A	737	534
Gas/Oil	N/A	742	N/A	741	b
National Total	229	721	418	461	22
NSPS II Units					
Eastern Low-Sulfur Coal	219	--	1,145	385	80
Eastern High-Sulfur Coal	0	--	417	417	47
Western Low-Sulfur Coal	0	--	1,347	1,347	67

N/A = Not applicable.
[a]Some coal units burn both coal and oil; these units attain reductions in SO_2 from both fuels.
b = Insufficient observations.

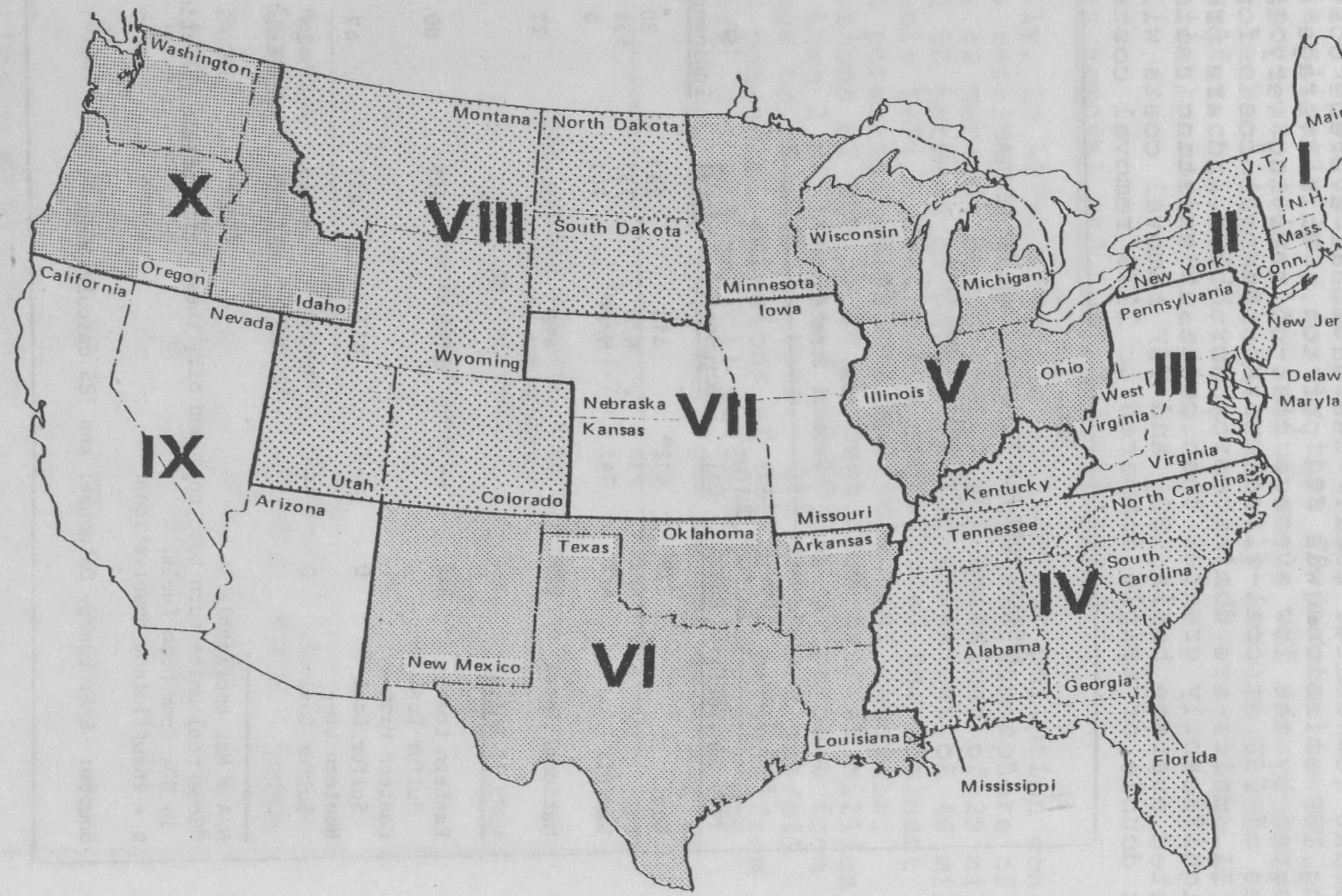
Source: EPA; Energy Database; and TBS calculations.

The Regional Effects of Environmental Regulations on the Electric Utility Industry

Each of the ten EPA regions (Figure I-4) has a unique profile of existing capacity by age of unit and fuel type and,

Figure I—4

EPA REGIONS



therefore, is affected differently by environmental regulations. Generally, units in the eastern regions are older than in the western regions. More than 30 percent of eastern capacity was installed before 1960; only 6 percent of western capacity is of that vintage. Seventy-five percent of coal-fired capacity and 45 percent of oil- and gas-fired capacity is in the East.

Each region's profile influences the most likely range of pollution control strategies for the region. The strategies, whether they involve equipment or fuels upgrading, are translated into costs that the average regional customer pays for service.

Regional variations in the average costs of compliance for unit categories capture the effects of differing fuel mixes, fuel quality, and preferred compliance strategies. These are summarized in Table I-9. Although the national average cost of pollution control across all units in 1979 was 3.88 mills per kWh, regional costs range from a high of 8.35 mills per kWh in Region I to a low of 1.07 mills per kWh in Region VI. In every region except Regions VI and VIII (which have relatively low average costs), low-sulfur fuel premiums dominate the costs.

Existing Capacity: Costs of Compliance

Oil-fired units relied exclusively on low-sulfur fuel to achieve compliance with SO_2 standards in 1979. This is reflected in the national average fuel oil premium of 6.86 mills per kWh, and substantially affects the eastern regional costs. Region I, with 99 percent of its fossil-fuel capacity in oil units, faced a low-sulfur oil premium of 7.56 mills per kWh, more than 90 percent of Region I's average pollution control costs. Without a change in capacity mix in the future, Region I's utility customers will face an even greater differential in costs if, as projected, the fuel oil premium escalates at a more rapid rate than the cost of alternative compliance methods.

The relatively high costs in Region II are driven by SO_2 control strategies at both oil-fired and coal-fired units. More than half of Region II's 1979 generation was provided by oil-fired units; one-quarter of its 1979 capacity was in

Table I-9

DETERMINANTS IN REGIONAL POLLUTION CONTROL COSTS

EPA Region	Dominant Capacity Type	Reasons for Costs (in order of relative magnitude)	Weighted Average Unit-Category Costs of Compliance (mills/kWh)
I	Pre-77 oil units	Fuel (oil) premium	8.35
II	Pre-77 coal and oil units	Fuel (coal and oil) premium; FGD capital and operating costs	6.18
III	Pre-77 coal and oil units	Fuel (coal and oil) premium; pre-72 coal FGD, TSP, and chemical control	4.36
IV	Coal units and pre-72 oil units	Fuel (coal and oil) premium; coal pre-72 TSP and chemical control	4.41
V	Coal units especially pre-72	Fuel (coal) premium; TSP control; chemical control	3.73
VI	Post-72 coal units, pre-72 gas units	Thermal and chemical control	1.07
VII	Coal units; pre-72 gas units	Fuel (oil) premium for coal units that also burn oil; TSP control	4.53
VIII	Coal units, especially post-76	TSP control; FGD for post-76 units; thermal and chemical control	2.94
IX	Pre-72 oil and gas units; pre-77 coal units	Fuel (oil) premium; thermal and chemical control for coal and oil units	4.53
X	72-76 coal units; pre-77 oil units	Fuel (oil) premium; TSP control; thermal and chemical control for coal units	2.35

Source: Energy Database and TBS calculations.

service before 1972. The costs of SO_2 control at coal units in Region II demonstrate the evolution of compliance strategies over time. In 1979, units installed before 1972 depended exclusively on improved fuel quality, while units installed after 1972 reflect the influence of NSPS I requirements in environmental standards. These units combined lower sulfur (but not compliance) coal with FGD equipment. Costs for the 1972-1976 units were no greater than for the pre-1972 units, but units installed after 1976, in meeting the NSPS I emissions limit of 1.2 pounds of SO_2 per million Btu, faced a tripling of costs for SO_2 control.

As of 1979, coal-fired capacity in Region VIII accounted for three-fourths of its total fossil-fuel capacity, with nearly one-third of the coal capacity in NSPS I units. Control costs for units with in-service dates after 1976 were 150 percent greater than the average costs for units of all vintages. The components of the high pollution control costs include TSP control systems, FGD equipment, thermal control equipment, and energy penalties and operating costs associated with the capital strategies. These costs reflect, at a minimum, the compliance requirements of the next two decades, as new coal units are subject to NSPS I, NSPS II, and at times even stricter best available control technology (BACT) requirements.

Expansion plans for utilities during the 1980s are projected to favor nuclear and coal capacity. All regions will participate in the growth of nuclear capacity, which will nearly double by 1990 if units currently under construction are completed as planned. Pollution control requirements for nuclear units resemble gas units in their emphasis on thermal and chemical control and in their low costs of compliance. Oil and gas conversions to coal will contribute to a substantial increase in coal capacity in Regions I, II, III, and IV, and new coal capacity will dominate total additions in all regions except IX and X.

New Coal-Fired Capacity: Costs of Compliance

The emphasis on new coal-fired capacity will present significant environmental concerns during the 1980s. Although NSPS I standards can be met without installing scrubbers, it is expected that eastern units generally will install FGD equipment with removal efficiencies of 85 to 90 percent and will burn high-sulfur coal. In the West, approximately one-third of all new capacity in Regions VI and VII will be scrubbed, and nearly all new capacity in Region VIII will be scrubbed.

The projected average cost of compliance for SO_2, TSP, thermal and chemical control for new 1980-1984 coal-fired capacity is 7.4 mills per kWh (in 1979 mills). The range is broad, from a low of 5.3 mills per kWh in Regions IX and X where the use of low-sulfur coal is the preferred strategy and scrubbers are rare, to a high of 8.6 mills per kWh in Region VIII where scrubbers with removal efficiency of 90 percent are combined with fuel that has less than 0.8 percent sulfur content.

Specific compliance strategies for NSPS II additions in the latter half of 1980 and beyond are difficult to predict, although scrubbers will be required on all coal-fired units. Individual units may choose a strategy of higher quality coal and 70 percent removal efficiency in the scrubber design or lower quality coal and 90 percent design removal efficiency. On the basis of the assumptions described in Chapter IV, eastern NSPS II compliance strategies are projected to cost 12.4 mills per kWh, while western compliance strategies will cost 9.4 mills per kWh.

National Issues That Affect Compliance

Several issues that are national in scope may have a bearing on future regional compliance requirements and costs. These include: regional growth patterns and their effects on emissions; PSD and regional air-quality-related values; and regional siting in attainment and nonattainment areas.

Changes in growth patterns can have a noticeable effect on air quality and on the level of control necessary to achieve and maintain the NAAQS. The Clean Air Act requires that states incorporate in their SIPs the application of appropriate controls based on growing or diminishing emissions. If industrial growth occurs at a higher than predicted rate in the Southeast or Southwest, or if conversions to coal increase SO_2 emissions in the East, powerplants may be required to meet more stringent emission limitations by installing complex and costly equipment.

Visibility impairment, particularly in the West, and acid precipitation, particularly in the East, are two air-quality-related values that may be the focus of much attention over the next few years. An important element of the PSD program is the consideration of these values during review of a permit application. To the extent that objectives in these areas change, and lead to changes in PSD requirements, compliance strategies and costs will change over time.

The technology requirement for major sources in attainment areas is less stringent than the requirement in nonattainment areas. Further, the offset requirement exists only in nonattainment areas. In the future, growth may be limited in nonattainment areas if offsets are unavailable or extremely costly, although interregional effects are difficult to quantify at this time.

The National Effects of Environmental Regulations on the Electric Utility Industry

To assess the effects of environmental regulations nationally over the next two decades, TBS examined five key indicators of economic and financial impacts: additions to plant in-service; external financing; operation and maintenance expenses; operating revenues; and consumer charges.

Pollution control regulatory coverage is typically related to the in-service or construction start date of a particular plant or boiler. In this analysis, costs are accounted for by unit in-service date. However, the year-end 1979 financial profile used for this study includes pollution control expenditures made prior to January 1, 1980. In order to determine a "baseline" projection excluding all environmental costs, these pre-1980 environmental capital costs were subtracted from the December 31, 1979, financial profile. Two distinct categories of pollution control costs are then added to the baseline projection--costs associated with pollution control equipment installed prior to 1980; and pollution control expenditures for equipment installed after 1979 plus any fuel premiums incurred after 1979.

The separation of the components of the total pollution control costs, particularly costs associated with units installed before 1980, is important for assessing the effect of specific pollution control regulations. The capital costs, and to some extent the operation and maintenance costs, associated with pre-1980 pollution control equipment cannot be altered and, therefore, can be considered "sunk." In contrast, the fuel premiums associated with pre-1980 requirements and the fuel, other operation and maintenance, and capital costs of post-1979 requirements can, to a considerable degree, change depending on the shape of future regulations. The focus of this discussion is on these "incremental pollution control" costs.

Table I-10 provides a comparison of the baseline financial projections, pre-1980 pollution control equipment costs, and incremental pollution control costs, expressed in 1982 dollars. Incremental pollution control changes in plant in-service amount to $87.3 billion over the forecast period, or approximately 8 percent of projected industry changes to plant in-service of $1,128.8 billion. Incremental external financing requirements are $70.5 billion. When pre-1980 pollution control equipment costs are included, external financing in the 1980-1999 period is reduced relative to the baseline projection by $2.3 billion because of the depreciation and retained earnings associated with the equipment already in

Table I-10

SUMMARY OF INDUSTRY CUMULATIVE EXPENDITURES
WITH AND WITHOUT POLLUTION CONTROLS

(billions of 1982 dollars)

	1980-1985	1980-1999
Changes in Plant In-Service		
Baseline	199.17	1,041.49
Pre-1980 Pollution Control Equipment	0	0
Incremental Pollution Controls	18.45	87.28
Total	217.62	1,128.77
External Financing		
Baseline	151.78	857.63
Pre-1980 Pollution Control Equipment[1]	(1.31)	(2.28)
Incremental Pollution Controls	18.17	70.46
Total	168.64	925.81
Operating Revenues		
Baseline	594.05	2,684.23
Pre-1980 Pollution Control Equipment	13.99	45.00
Incremental Pollution Controls	44.31	218.26
Total	652.35	2,947.49
Operation and Maintenance Expenses		
Baseline	404.28	1,671.88
Pre-1980 Pollution Control Equipment	8.42	35.69
Incremental Pollution Controls	39.86	154.57
Total	452.56	1,862.14
Consumer Charges[2] (mills per kWh)		
Baseline	44.35	51.15
Pre-1980 Pollution Control Equipment	0.91	0.67
Incremental Pollution Controls	3.65	4.34
Total	48.91	56.16

Note: See Chapter VI, pages VI-36 to VI-39, for a definition of the cost measures used above.

[1]While there are no plant additions for pre-1980 pollution controls in the 1980-1999 period, external financing requirements are reduced because of the greater amounts of plant in-service as of 1980 for the pre-1980 equipment. This increases depreciation and retained earnings, and reduces external financing requirements.

[2]Consumer charge figures are not cumulative, but represent the annual consumer charges for the last year of the period indicated measured in mills per kilowatt-hour.

Source: PTm(Electric Utilities).

fact on the industry's balance sheets. Cumulative pollution control operating revenues through 1999 are $263.3 billion, or 9 percent of the total of $2,947.5 billion, as shown in Table I-10. Cumulative pollution control operation and maintenance expences are $190.3 billion, slightly more than 10 percent of the total of $1,862.1 billion. Consumer charges in 1999 for pollution controls are 5.01 mills per kWh, or 9 percent of the total 56.16 mills.

Table I-11 provides a breakdown of plant additions by pollutant and time period. SO_2 controls represent $43.3 billion or about half of all the major pollution control-related expenditures over the 1980-1999 period. TSP controls account for $21.9 billion or 25 percent of total pollution control-related plant additions, while water pollution and solid waste control costs represent the remaining $22.0 billion or 25 percent. Of the total of $87.3 billion of pollution control

Table I-11

CHANGES IN PLANT IN-SERVICE ATTRIBUTABLE TO POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline Changes in Plant In-Service	199.17	1,041.49
Pre-1980 Pollution Controls Equipment	0	0
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	0	0
Fuel Premium[1]: Post-1979 Units	0	0
SO_2	8.91	43.32
TSP	5.68	21.94
Solid Waste	1.85	10.98
Water	2.01	11.04
Total Pollution Controls	18.45	87.28
Total	217.62	1,128.77

[1]Fuel premiums and other pre-1980 pollution controls do not have capital charges associated with them in the 1980-1999 period. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

plant additions, 16 percent or $13.6 billion is attributable to capacity penalties associated with new pollution control equipment.

The external financing requirements associated with pollution controls amount to $68.2 billion or about 7 percent of the industry's projected total requirement (Table I-12). The contribution to external financing requirements by pollutant corresponds closely to their contribution to plant additions. External financing requirements will be higher in the early years of the period as the industry raises capital to finance control equipment retrofits and pollution control equipment for oil-to-coal reconversions. This fact, coupled with

Table I-12

EXTERNAL FINANCING EFFECTS OF POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline External Financing	151.78	857.63
Pre-1980 Pollution Controls Equipment[1]	(1.31)	(2.28)
Incremental Pollution Controls		
Fuel Premium[2]: Pre-1980 Units	0	0
Fuel Premium[2]: Post-1979 Units	0	0
SO_2	8.78	35.21
TSP	5.41	17.24
Solid Waste	1.93	9.03
Water	2.05	8.98
Total Pollution Controls	16.86	68.18
Total	168.64	925.81

[1]While there are no plant additions for pre-1980 pollution controls in the 1980-1999 period, external financing is reduced because of the greater amounts of plant in-service as of 1980 for the pre-1980 equipment. This increases depreciation and retained earnings, and reduces external financing requirements.

[2]Fuel premiums are operating costs and do not have capital charges associated with them. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

capital constraints that currently exist in the industry, could create difficulties for individual utilities.

Pollution control costs represent $263.3 billion, or approximately 9 percent of the industry's total revenue requirements during the 1980-1999 period (Table I-13). Post-1979 SO_2 controls including all fuel premiums represent 62 percent of the total pollution control-related revenue requirements. The price premium for low-sulfur fuels alone represents the largest single component of the increase in revenue requirements--almost 40 percent. The other pollution control categories contribute less importantly to total cost increases and therefore revenue requirements. Post-1979 solid waste disposal costs, however, do rise over the period and become a significant fraction, 7 percent, of total cumulative pollution control-related revenue requirements by 1999.

Table I-13

OPERATING REVENUE EFFECTS OF POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline Operating Revenues	594.05	2,684.23
Pre-1980 Pollution Controls Equipment	13.99	45.00
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	32.70	96.45
Fuel Premium[1]: Post-1979 Units	1.19	7.76
SO_2	5.31	59.30
TSP	2.01	22.04
Solid Waste	2.15	19.40
Water	0.95	13.31
Total Pollution Controls	58.30	263.26
Total	652.35	2,947.49

[1]Fuel premiums are typically considered SO_2 costs but are shown separately here because of their large effect on total pollution control costs. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

Operation and maintenance expenses associated with pollution control equipment are expected to be $190.3 billion, or 10 percent of the total operation and maintenance expenses (Table I-14). The vast majority of pollution control-related operation and maintenance expenses reflect the premium paid by utilities for low-sulfur fuels. Costs associated with the operation and maintenance of scrubbers (SO_2 controls) installed after 1979 also represent a significant portion of the total, at 14 percent. Solid waste is the only other category for which post-1979 operation and maintenance expenses are significant, accounting for approximately 6 percent of total pollution control-related operation and maintenance expenses. Energy penalties resulting from scrubbers, TSP controls, waste disposal controls, and thermal controls installed after 1979 represent 3.4 percent of total pollution control operation and maintenance expenses, or $6.5 billion.

Table I-14

OPERATION AND MAINTENANCE EXPENSE EFFECTS OF POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline O&M Expenses	404.28	1,671.88
Pre-1980 Pollution Controls Equipment	8.42	35.69
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	34.09	100.52
Fuel Premium[1]: Post-1979 Units	1.24	8.10
SO_2	2.49	26.05
TSP	0.02	3.51
Solid Waste	1.67	11.48
Water	0.35	4.94
Total Pollution Controls	48.28	190.29
Total	452.56	1,862.17

[1]Fuel premiums are typically considered SO_2 costs but are shown separately here because of their large effect on total pollution control costs. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

Consumer charges attributable to pollution control expenditures are shown in Table I-15. The increased cost per kWh is approximately 9 percent in 1999. As is the case with other measures of the effects of pollution controls, post-1979 SO_2 controls including fuel premiums represent the single largest cost category, accounting for 57 percent of the total increase in consumer charges attributable to pollution control regulations. The remaining 30 percent is split relatively evenly between costs for controls installed as of 1979, TSP controls, water pollution controls, and solid waste controls.

Table I-15

CONSUMER CHARGE EFFECTS OF POLLUTION CONTROL REGULATIONS

(mills per kilowatt-hour in 1982 dollars)

	1985	1999
Baseline Consumer Charges	44.35	51.15
Pre-1980 Pollution Controls Equipment	0.91	0.67
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	2.12	1.00
Fuel Premium[1]: Post-1979 Units	0.13	0.17
SO_2	0.71	1.70
TSP	0.30	0.59
Solid Waste	0.26	0.49
Water	0.13	0.39
Total Pollution Controls	4.56	5.01
Total	48.91	56.16

[1]Fuel premiums are typically considered SO_2 costs but are shown separately here because of their effect on total pollution control costs. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

TBS examined two alternative scenarios in the course of this study. The summary results of that examination are presented in Figure I-5. The changes in assumptions used to develop these scenarios are:

- Reduction in the growth rate during the 1980-1999 period from 3.0 percent to 2.0 percent, and

- Nuclear prohibition after 1989, with coal in place of the nuclear additions assumed in the base case.

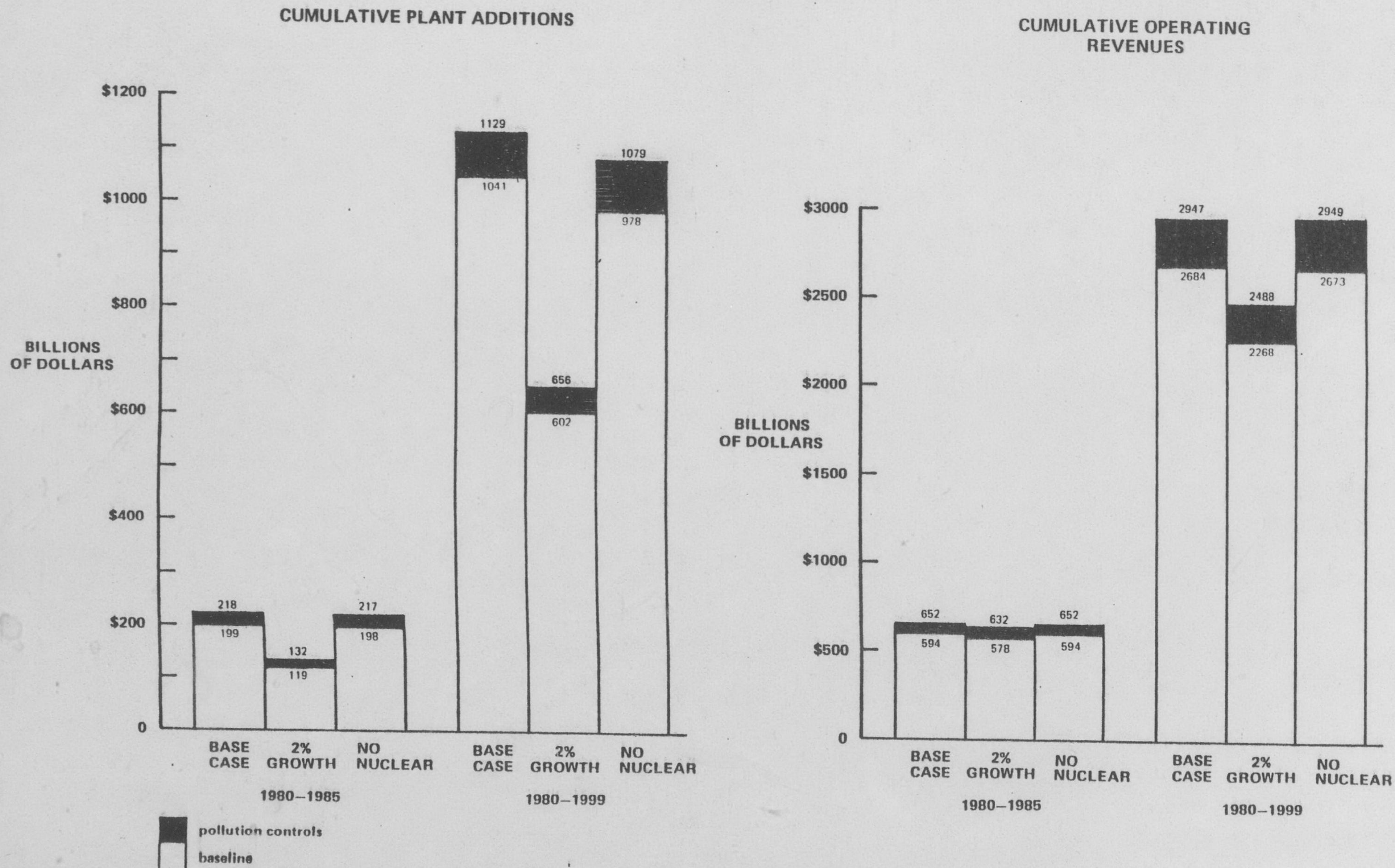
A decrease in the industry's annual rate of growth results in lower baseline plant additions and consumer charges, and lower pollution control expenditures. However, the percentage increase in consumer charges due to pollution controls is essentially unchanged from the base case.

Baseline and total plant additions are slightly lower if nuclear additions are assumed to terminate after 1989. However, cumulative industry pollution control additions to plant in-service through 1999 are slightly higher than they would be if nuclear additions were allowed to continue after 1989. Total operating revenues are virtually the same under both scenarios. Consumer charges in 1999 are also essentially unchanged under either scenario.

Figure I–5

COMPARISON OF CUMULATIVE PLANT ADDITIONS AND OPERATING REVENUES UNDER ALTERNATIVE SCENARIOS

CONSTANT 1982 DOLLARS



Source: PTm(Electric Utilities).

ENVIRONMENTAL
REGULATIONS

CHAPTER II

AN OVERVIEW OF ENVIRONMENTAL REGULATIONS AFFECTING ELECTRIC UTILITIES

CONTENTS

CONTENTS
(continued)

II. AN OVERVIEW OF ENVIRONMENTAL REGULATIONS AFFECTING ELECTRIC UTILITIES

INTRODUCTION

Environmental regulations applicable to the electric utility industry are extensive because the industry is a major generator of air, water, and solid waste pollution. They are also complex and evolving because a multiplicity of interests, objectives, and technical and scientific developments have influenced and are influencing their development.

Although the electric utility industry traditionally has had its own programs for controlling air, water, and solid waste pollution, further requirements pertaining to each type of pollutant have evolved separately through legislative, regulatory, and legal processes at the local, state, and federal levels. The specific requirements often vary from plant to plant, sometimes even from unit to unit in a plant, depending on a variety of considerations, including a generating unit's age, location, fuel type, and technical configuration. In addition to the air, water, and solid waste regulations, the industry has to comply with other environmentally related regulations, such as those that control and protect endangered species and coastal zones.

In some geographic areas, it is arguable that regulations affecting local utilities would be just as strict as they are now even in the total absence of federal regulations. In some other geographic areas, it is arguable that federal requirements are the sole driving force behind some existing regulations. However, beause of the complexity of the interactions among regulations, the appropriateness of these arguments cannot readily be determined. Further, responsibility for the detailed specification and enforcement of particular regulations is often delegated from one level of government to another. Thus, this study does not attempt to partition environmental regulations into those attributable to federal, state and local initiatives.

A number of common themes apply to air, water, and solid waste regulations. These themes are the involvement of numerous actors in the evolution of environmental regulations;

the multiplicity of health, welfare, and economic considerations to be met by the regulations; the paucity of conclusive data on how well specific regulations meet these objectives; and the tensions between flexibility in dealing with specific situations, complexity, and predictability in their design. So, in addition to discussing air, water, and solid waste regulations separately, this chapter examines how they interact.

THE CLEAN AIR ACT AND REGULATIONS IMPLEMENTING THE ACT

The electric utility industry has been a major focus of air regulation because of the large overall quantity of pollutants it emits and because of the large amounts of certain pollutants some plants emit. The regulated pollutants are all combustion by-products. For example, through combustion, natural gas, coal, and oil form nitrogen oxides (NO_x); sulfur and sulfur compounds contained as impurities in coal and oil become sulfur dioxide (SO_2); and other solid impurities in coal and oil emerge as particulate matter (TSP and fly ash).

Despite a shift to lower-sulfur fuels, the installation of considerable amounts of pollution control equipment, and changes in boiler design and operation already accomplished by 1977, the electric utility industry that year still emitted about 18 million tons of SO_2, about 7 million tons of NO_x, and about 3 million tons of total suspended particulates (TSP).[1] These amounts accounted for about 65, 31, and 25 percent, respectively, of total man-made emissions of each of these pollutants. In the case of SO_2, the average electric utility plant had uncontrolled emissions substantially larger than other industrial sources.

As reported in Chapter IV of this study (developed from 1979 utility submissions in the Energy Database), the industry emitted about 17 million tons of SO_2, about 7 million tons of NO_x, and slightly less than 1 million tons of TSP in 1979.

During the late 1960s, Congress concluded that previous state and federal initiatives to address the problems of air

[1]U.S. Department of Commerce, Bureau of the Census, "Air Pollutant Emissions by Source, 1970 to 1979," Statistical Abstract of the United States, 1979.

pollution, including the Clean Air Act of 1964, were inadequate. So in 1970, Congress passed the Clean Air Act Amendments (generally known as the Clean Air Act), which amended the preexisting law into the overall structure it retains today. The amended act established a new legal framework to protect and enhance air quality and to oversee the implementation of air quality control programs.[2] It directed EPA to establish, and give states the responsibility for implementing, nationwide National Ambient Air Quality Standards (NAAQS) for both new and existing sources of pollutants and industry-specific new source performance standards (NSPS) (see Figure II-1).

In 1977, further amendments extended the deadline for the attainment of all primary (health-related) standards. States were to prepare and submit to EPA, by January 1979, revised implementation plans for all nonattainment areas. The plans were to provide for the implementation of all "reasonably available control measures as expeditiously as practicable" for existing sources and for "reasonable further progress," demonstrated on an annual basis, toward meeting standards. The amendments also established a "prevention of significant deterioration" (PSD) program to protect air that was cleaner than the NAAQS. The amendments codified and expanded regulations issued by EPA in response to a court order, and they also changed the statutory standards under which NSPSs for powerplants were issued. Congress is again reviewing the Act.

The following section describes the major provisions of the Act, along with the major decisions taken by EPA and the courts to apply these provisions under changing conditions.

National Ambient Air Quality Standards

Promulgated by EPA in 1971, the NAAQS established ambient air quality standards for seven pollutants during the 1970s.[3] Electric powerplants emit significant amounts of three of these pollutants--SO_2, NO_x, and TSP. Although they also emit another of these pollutants, carbon monoxide (CO), this study does not discuss it because CO is predominantly associated with motor vehicle emissions.

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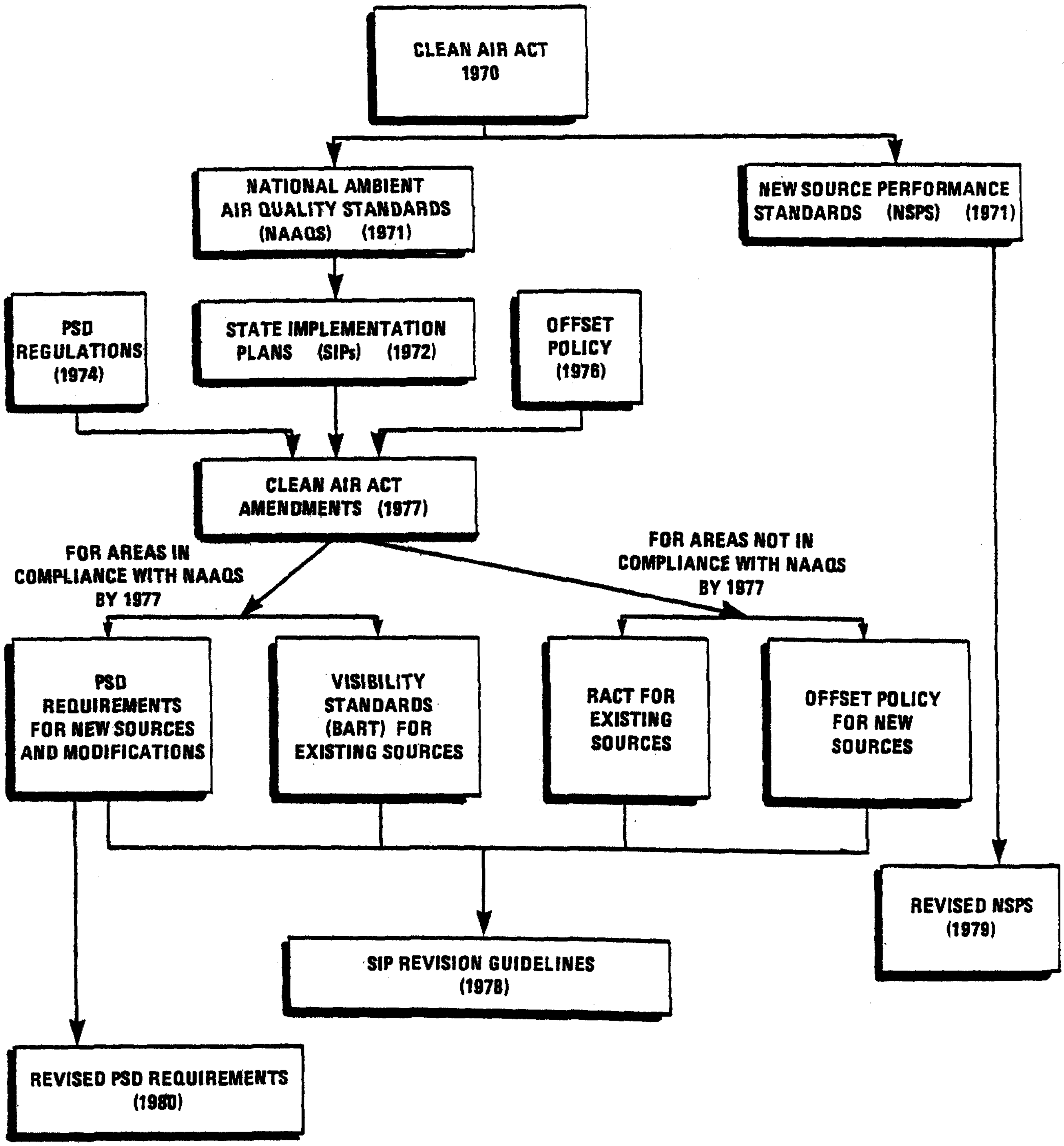
[2]The Clean Air Act (as amended), Public Law 91-604; December 31, 1970.
[3]Technical amendments to the Clean Air Act, Public Law 92-157; November 18, 1971.

Figure II—1

OVERVIEW OF FEDERAL
AIR QUALITY REGULATIONS



The NAAQS affect both new and existing plants. Primary NAAQS were designed to protect human health, "allowing an adequate margin of safety." Secondary NAAQS were established to protect "public welfare," defined as protecting such valued things as vegetation, property, and scenery. For primary and secondary NAAQS, the Agency promulgated both short-term standards to protect against acute effects of exposure to high pollutant concentrations as well as long-term standards to protect against the effects of chronic exposure to lower concentrations.

New Source Performance Standards

To ensure continuing improvements in air quality, the Clean Air Act also required EPA's Administrator to set technology-based (or performance) standards for new plants. These standards are based on the "best continuous system of adequately demonstrated technology," considering cost, energy, and nonair environmental effects. NSPS apply whether or not an area meets the NAAQS.

NSPS for the electric utilities industry were first established in 1971 and revised in 1979. The 1971 NSPS set plant emission limits that could be met either by using low-sulfur fuels or by installing pollution control equipment. However, after Congress passed the 1977 amendments to the Clean Air Act--which were intended to preserve the market for higher sulfur coals and to minimize emissions from new plants burning lower sulfur coals, especially in the West--the 1979 NSPS required plants to use pollution control equipment to reduce emissions regardless of the fuel burned.

State Implementation Plans

Under the Clean Air Act, all states must attain and maintain the NAAQS. The 1970 amendments directed them to submit state implementation plans (SIPs) to EPA for approval and promulgation before July 1972. Although it intended for these plans to lead to attainment of the primary NAAQS by mid-1975, the Act provided for a possible two-year extension to 1977.

To account for local circumstances, the country was divided into 247 air quality control regions (AQCRs). In essence the SIPs were intended to reduce overall emissions to a level that ensured that all AQCRs within each state met the NAAQS. Overall emission reductions within an AQCR would be allocated by the states among plants in the AQCR.

Attainment Policies

It is the responsibility of the states, with EPA review and approval, to determine whether areas within the state are attaining the NAAQS. The designation of an area as attainment means that controls to prevent deterioration of the air quality will be required. This section discusses the applicable attainment policies.

Prevention of Significant Deterioration

A major gap between the NAAQS and the NSPS concerned areas of the country where air quality was already cleaner than what the 1971 standards required. Under the NAAQS, air quality in these areas, some of which were pristine, could deteriorate to the level of the national standards. As a consequence, industrial growth might tend to be directed toward these regions because emission-related restrictions on growth would be less extensive. Therefore, it was feared that technology-based NSPS would not provide the framework for sufficiently protecting areas with relatively pristine air quality while not discouraging growth.

As the result of a 1972 suit that the Sierra Club brought against EPA, the U.S. Supreme Court upheld the opinions of lower courts and required the Agency to develop regulations to prevent the significant deterioration of pristine areas.[4] In December 1974, EPA issued its initial prevention of significant deterioration (PSD) regulations, which Congress later modified and incorporated into the 1977 amendments to the Clean Air Act.[5]

The PSD regulations directed the states to include in their implementation plans limitations to building or modifying sources of pollution in PSD areas. These areas were divided into three categories:

- Class I--pristine areas with the tightest controls;
- Class II--moderate-growth areas capable of tolerating some deterioration in air quality; and

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[4] Sierra Club v. Ruckelshaus, 4 ERC 1205 (1972).
[5] 39 FR 42510, 40 CFR 52.21, July 1, 1977.

- Class III--areas designated for major industrial growth where the deterioration in air quality could be greater although still subject to limits.

The PSD regulations set allowable increments, or limits for <u>increases</u> in pollutant concentrations from baseline levels in these areas (with the provision that the NAAQS be maintained).[6] They also subjected new and modifying plants to a requirement that "best available control technology" to control emissions be installed. BACT was to be determined on a case-by-case basis, but could not be less stringent than NSPS.

In 1978, EPA revised its PSD requirements to meet the new requirements. Litigation followed and resulted in the invalidation of significant portions of these regulations. The court decision resulted in major restructuring of the PSD regulations in 1980, particularly regarding explicit definition of "major modification" and "stationary source," and criteria for exclusion from full PSD review. Most important from the standpoint of electric utilities was the exclusion from full PSD review, under certain conditions, of a source that voluntarily switched to a more polluting fuel (i.e., coal conversions). This exclusion has been particularly significant in such areas as the Northeast where extensive fuel switching has occurred or is planned. An exclusion of potential future significance is that of federally mandated coal conversions and natural gas curtailments.

<u>Visibility Standards</u>

In the 1977 Clean Air Act Amendments, Congress made provisions for the protection of visibility in large national parks and wilderness areas that, for the most part, enjoy the benefits of very clean air. The Act states a policy against visibility degradation caused by air pollution from human activities and calls for controls on large stationary sources of pollution--both new and existing--that impair visibility in these Class I areas.

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[6]Abstracting from many of the complexities, existing levels are basically defined from a baseline of August 7, 1977.

Visibility is impaired by atmospheric gases and small particles either absorbing or scattering light. Powerplants produce three pollutants that cause these effects. Nitrogen oxides (NO_x) emitted from the stack turn into NO_2 gas and absorb light at the blue end of the spectrum. This, in turn, lends a brown or reddish color to the air. SO_2 emitted from the stack turns into sulfates that, together with the fine-particle component of TSP, scatter light and produce a dulling or hazy effect. Both discoloration and haze have degraded visibility in Class I areas, particularly in western areas, where the air is naturally so pristine that only a very small amount of pollution produces a perceptible effect.

In December 1980, EPA promulgated regulations to implement the visibility protection program called for by Congress. In its supporting analysis, the Agency found no existing sources that would have to add controls to protect visibility. This finding does not mean that no existing sources are impairing visibility. Rather, it means that the environmental-energy-cost-balancing approach that the Act requires in these decisions could not justify the addition of controls to those sources identified.

Nonattainment Policies

As the 1975 NAAQS compliance deadline passed and as the allowed two-year extension was also exhausted, it became apparent that the Agency would have to deal with areas that did not meet the NAAQS compliance schedule for particular pollutants. Even the limited additional pollution allowed by the NSPS would push these areas further out of compliance. The Agency responded to this problem by developing the offset policy.

Offset Policy

Originally promulgated in December 1976 and revised in 1979, the offset policy applies to new and modified facilities.[7] Under the policy, EPA will grant a permit to build a major new facility that will increase pollution in a nonattainment area for a particular pollutant if the following three criteria are met:

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[7]Public Law 95-95, Section 129(A).

First, the construction must result in a net reduction in emissions in the area. The permit applicant must provide the emissions offset internally or must arrange with local sources of pollution to reduce their emissions to more than offset the emissions from the new source. Such a reduction is unnecessary in an attainment area. Thus, a new plant in an SO_2 nonattainment area would have to negotiate an overall reduction in SO_2 emissions but would be subject only to PSD requirements for TSP.

Second, the new facility must use technology to realize the lowest achievable emission rate (LAER). Like the best available control technology (BACT), which is applied to new sources in attainment areas, LAER cannot be less stringent than NSPS (either the 1971 or 1979 NSPS, depending on a plant's commencement date). Permit writers are not, however, instructed to account for energy and economic effects in making LAER determinations, as they are in making BACT determinations. In addition, they are required to set LAER emission reduction requirements at the best level established for any plant by any state's SIP. Consequently, while BACT is often but not always equivalent to NSPS, LAER may impose more stringent requirements.

Finally, other plants in the state owned by the applicant must be in compliance with the applicable SIP guidelines.

The 1977 Amendments

When Congress enacted the 1977 amendments to the Clean Air Act, it extended until December 1982 the deadline for areas that had not yet attained the standards for the major powerplant pollutants--particulates, NO_x, and SO_2. At the same time, it required states to rewrite their implementation plans for these pollutants. States that did not submit a satisfactory implementation plan by July 1, 1979, were to be forbidden to issue permits to new major stationary sources.

The new plans would have to contain new source review procedures patterned on the offset provisions discussed above, as well as a number of other provisions, including the installation of "reasonably available control technology" on existing sources.

SIP Revision Guidelines

Implementing the 1977 amendments, the SIP revision guidelines were promulgated in 1978 to ensure nationwide attainment of the NAAQS by 1982.[8] They incorporated the offset policy for new plants in nonattainment areas, and also, in some cases, required emission reductions at existing plants. States were to issue revised SIPs conforming to the guidelines by June 1979. Until then, the offset policy would remain in effect for new plants, and the 1972 SIPs would apply to existing plants. States that did not revise their SIPs in a timely manner were to be forbidden to issue permits for new or modified major sources of air pollution.

To accomplish the objective of the guidelines, the 1977 amendments established a tracking procedure called "reasonable further progress," which had not existed in the original SIP regulations.[9] As defined by the 1977 amendments, reasonable further progress requires annual reductions in emissions of nonattainment pollutants that are consistent with the attainment of the NAAQS by 1982.

Applied to existing plants, reasonable further progress is interpreted as reasonably available control technology (RACT). This requirement has been defined as "the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility."[10] In using this language, the Agency "has made it clear that RACT calls for stringent or even 'technology forcing' requirements that go beyond off-the-shelf technological controls."[11] For certain industries (primarily emitters of volatile organic compounds), the Agency has issued RACT guidance in the form of control techniques guidance (CTG) documents describing state-of-the-art control technology. These documents, however, have not been developed for the electric utility industry. Consequently, for electric utility plants, states make case-by-case judgments of what constitutes RACT.

Attainment and Nonattainment Interactions

The offset policy for nonattainment areas and the PSD policy for attainment areas interact in two major cases: cross-boundary effects and pollutant-specific violations.

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[8] Public Law 95-95, Section 129(a).
[9] 44 FR 3284.
[10] Clean Air Act, Section 172(b)(3) (44 FR 20375).
[11] Ibid.

Cross-boundary effects increase the stringency of pollution control requirements if a source in an attainment area is subject to the requirements of a neighboring nonattainment area. As an example, a proposed source in an attainment area that contributes to an NAAQS violation in a neighboring area either would have to provide sufficient offsets to cover its contribution to the violation (but only for its contribution to the violation and not for its full emissions), or would have to control its emissions so as to prevent the contribution.

Attainment and nonattainment status are determined for individual pollutants. Consequently it is possible that a plant in a nonattainment area will be subject to PSD requirements for attainment pollutants and to offset requirements for nonattainment pollutants. Since the procedures (and the permit-issuing authority) for offset and PSD programs may differ, the level of a plant's emissions can subject it to two full sets of preconstruction reviews.

Other Clean Air Act Provisions

Several other important provisions are included in the Clean Air Act amendments. Two that have been the focus of considerable recent attention are stack height requirements and Section 125 regional coal use.

Stack Heights

In the 1977 Clean Air Act amendments, Congress stated that sources of pollution could not use smokestacks taller than good engineering practice (GEP) or other dispersion techniques in place of constant emission controls to meet air quality standards.

Emission limitations are set on the basis of ground-level ambient pollutant concentrations. A tall stack releases emissions into the atmosphere at a high level so that they can disperse and become less concentrated by the time they reach the ground than if they were released from a shorter stack. If the ground-level concentrations are lower than the legal limit, then the emission rate can be higher, and sources can avoid putting on constant emission controls.

Section 125 Regional Coal Requirements

Section 125 of the Clean Air Act grants the President the authority to prohibit large stationary sources of pollution from burning fuels other than locally or regionally available coal to meet SIP requirements. Such a prohibition can be made if EPA's Administrator or the President determines that it is necessary to prevent or minimize significant local or regional economic disruption or unemployment.

In effect, this section of the Act could potentially limit switching to lower-sulfur coal as a compliance strategy for utilities. For meeting a given emission limitation, this strategy is generally preferred by utilities to the alternative compliance option--installing sophisticated pollution control equipment (e.g., scrubbers).

Although Ohio and Illinois submitted petitions for action on Section 125, EPA determined that such action was unwarranted. One of the major factors impeding the use of 125 is the fact that it requires the Agency to make difficult distributional decisions. The absence of precise definitions for such important terms as "local," "regional," and "significant economic disruptions" makes these decisions particularly complicated.

The inherent limitations of Section 125 can best be illustrated by briefly analyzing the two potential responses that can be applied to requests for action. First, by allowing the utility to shift to lower-sulfur coal, the economic disruption can simply be allowed to occur. Here, a large portion of the costs would be borne (implicitly) by the dislocated high-sulfur coal miners and other individuals whose livelihoods depend upon the affected mines' operations.

The second alternative, whereby the utility would be required to install pollution control equipment, would distribute the costs across the utility's customers. The consequences of this choice, however, may prove to be more burdensome than those associated with the first option: consumer charges may increase considerably. In this instance, the Agency must first attempt to estimate the magnitude of the increases and then, given the statutory requirement that the final costs to consumers be taken into acount, judge their reasonableness. In addition, its application is likely to give one segment of the coal market an advantage over another, possibly resulting in miners in one state being employed at the expense of miners in another state.

Although the possibility exists that a 125 action could be taken and that the utility involved would be required to continue to burn local coal and to install additional pollution control equipment, this section of the Act has not yet been invoked.

THE CLEAN WATER ACT AND REGULATIONS IMPLEMENTING THE ACT

Water regulations have affected electric utilities less than air regulations. Because the industry uses water primarily for cooling, pollutants in most waste streams from electric powerplants tend to be similar and not highly concentrated. However, the volume of these streams can be very large.

The electric utility industry is the nation's largest industrial user of water, despite the fact that water use by steam electric utilities has decreased dramatically over the past decade. According to the Bureau of the Census, in 1975 steam electric plants used 89 billion gallons of water per day; by the year 2000, this figure is expected to decrease to 80 billion gallons.[12] Even with continuing declines in usage per plant, electric utilities will account for more than one-third of the nation's total water use over the next two decades and for more than than twice as much water use as all other industrial plants combined.

Plants with once-through cooling systems use the most water. Once-through water is taken from a water body, used to recondense spent steam that has passed through a turbine, and discharged directly back into the water body after it has passed through the condenser once. Pollutants potentially subject to control in once-through cooling water are chlorine (used to control algae growth within the condenser) and heat.

Recently, for environmental and water supply reasons, electric powerplants have moved toward recirculating cooling systems. In such systems, water used to recondense spent steam is passed through a cooling tower or (less frequently) a cooling pond. The waste stream, or blowdown, from such systems is the periodic discharge from the system needed to remove accumulated impurities. Pollutants potentially subject to control in recirculating systems are chlorine, chemical additives used to control scaling and corrosion within the system, and heat.

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[12] U.S. Department of Commerce, Bureau of the Census, "Estimated Daily Water Use: 1940 to 1975 and Projections to 2000," Statistical Abstract of the United States, 1979.

Ash transport water wastes are emitted by plants that have wet-ash-handling systems to sluice fly ash from a boiler's exhaust stack or ash from the bottom of a boiler. Pollutants potentially present in ash-handling water include total suspended solids, oil, grease, and trace elements from ash.

Metal-cleaning and low-volume wastes are a third category of powerplant waste streams. Metal-cleaning wastes result from occasional operations to remove scaling and corrosion that can accumulate on boilers and condensers at all steam electric plants. Low-volume wastes are a collection of small, intermittent streams that also are present at all plants. Wastewater from flue gas desulfurization systems is considered part of low-volume wastes. Pollutants potentially present in these waste streams include copper, iron, oil, grease, and total suspended solids, as well as chemical preparations used to clean metals.

Runoff, the final waste category, is created when precipitation falls on various powerplant components, such as coal storage, ash handling and disposal, construction, and chemical handling equipment. Powerplants are required to have runoff collection systems, and discharges from these systems are subject to effluent limitations.

In 1972, Congress passed the Federal Water Pollution Control Act. That act was amended by the Clean Water Act of 1977.[13] The approach taken by regulations implementing the Clean Water Act differs in important respects from that taken by air regulations. Whereas ambient air quality standards drive regulations controlling air pollution, technology standards under section 301 of the Act dominate water pollution control. Consequently, while air regulations have imposed different standards for attainment and nonattainment areas, federal regulations to control water pollution generally have not differentiated among regions of the country. States, of course, can and do impose additional water-quality-related requirements.

The next section discusses the technology-based standards governing the electric utility industry and other provisions where these standards are insufficient to protect the environment.

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[13] The Federal Water Pollution Control Act (P.L. 92-500) as amended by the Clean Water Act of 1977 (P.L. 95-217).

NPDES and Effluent Limitation Guidelines

The basic mechanism for enforcing the requirements of the Clean Water Act is the national pollution discharge elimination system (NPDES) permit required for all point-source discharges into the navigable waters of the United States.[14] NPDES permits incorporate specific pollution control requirements based on effluent limitation guidelines that EPA has periodically issued. These guidelines fall into the following major categories:

- Best practicable control technology (BPT), specifying standards to be met by July 1, 1977;
- Best available technology economically achievable (BAT), specifying standards for toxic pollutants to be met by July 1, 1984;
- Best conventional technology (BCT), specifying conventional pollutant standards to be met by July 1, 1984;
- New source performance standards (NSPS), setting requirements for plants commencing construction after a given date (usually the date of proposal of the regulations containing the NSPS); and
- Pretreatment standards for existing sources (PSES) and for new sources (PSNS) applying to discharges to publicly owned treatment works (POTWs).

In practice, the major standards applying to electric utilities have been BPT, BAT, and NSPS (see Table II-1). Few existing electric utility plants discharge to POTWs, and no such discharges are expected in the future. Consequently,

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[14]The NPDES permits do not cover two types of water discharges: nonpoint discharges from such diffuse sources as agricultural irrigation and runoff, and discharges to publicly owned treatment works. Both have limited applicability to the electric utilities industry.

PSES and PSNS have limited applicability. BCT standards have not been established because BAT standards cover waste streams which also contain conventional pollutants.

1974 Best Practicable Control Technology Standards

EPA promulgated BPT standards for the electric utility industry in 1974. These standards, which had a compliance deadline of July 1, 1977, applied to all the major waste streams--cooling water, ash transport water, metal-cleaning wastes, low-volume wastes, and boiler blowdown. In addition to standards for specific waste streams, the 1974 BPT regulations required all discharges to control acidity (pH) levels and prohibited any discharge of polychlorinated biphenyls (PCBs).

The technologies required to meet BPT standards were relatively straightforward. Management practices, such as increased care in the application of chlorine, could meet the limitations on chlorine discharges in cooling water; sedimentation in settling ponds could satisfy the standards for total suspended solids (TSS), oil and grease, and metals in the remaining waste streams; management practices using non-PCB chemical additives could control PCBs; and adding chemicals could enable plants to meet pH limits.

1975 Best Available Technology and New Source Performance Standards

In 1975 the Agency promulgated BAT standards and NSPS for plants beginning construction after 1974. The BAT standards originally had a 1983 compliance deadline, but the 1977 amendments extended it to 1984.

For most waste streams, the 1975 BAT and NSPS limitations reiterated BPT limits. There were some exceptions, however: the BAT and NSPS requirements were considerably more stringent for bottom-ash transport water; for fly-ash transport water, BAT was the same as BPT, but NSPS mandated zero discharge; and the 1975 BAT limited and the 1975 NSPS prohibited discharges of certain corrosion inhibitors from recirculating cooling water.

Table II-1

EVOLUTION OF WATER QUALITY REGULATIONS SINCE 1974

	WASTE STREAM						
				Recirculating Cooling Water		Once-Through Cooling Water	
Date and Regulation	Low-Volume Wastes, Boiler Blowdown, Metal Cleaning Wastes, Runoff	Bottom Ash Transport Water	Fly Ash Transport Water	Chemical Discharge	Thermal Discharge and Intake Controls	Chemical Discharge	Thermal Discharge and Intake Controls
1974 BPT	Limits on TSS, oil and grease, copper, iron; LVW: TSS, oil, grease only	Limits on TSS, oil and grease	Limits on TSS, oil and grease	Limits on chlorine	No limit	Limits on chlorine	No limit
1975 BAT	No change from BPT	Limits on TSS, oil and grease equal to 8 percent of BPT	No change from BPT	Chlorine: no change from BPT Add: limits for zinc, chromium, phosphorous	No discharge above makeup water temperature	No change from BPT	No limit
1975 NSPS	No change from BPT	Limits on TSS, oil and grease: 5 percent of BPT	Zero discharge	Same as BAT	Same as BAT	No change from BPT	No discharge above makeup water temperature
1976 316b Regulations					Best Intake Structures		Best Intake Structures
1976 *Appalachian Power v. Train*			NSPS remanded		NSPS and BAT remanded		NSPS remanded
1977 *Appalachian Power v. Train*					Intake controls remanded		Intake controls remanded
1980 Proposed Guidelines	BAT, NSPS: no change from BPT	BAT, NSPS: no change from BPT (1975 BAT and NSPS rescinded)	Zero discharge for new plants only	More stringent chlorine limits zero discharge of 129 priority pollutants	No limit established	More stringent chlorine limit	No limit established
Current Effective Requirements	1974 BPT	1974 BPT	1974 BPT	1975 BAT, NSPS	Best Engineering Judgment	1974 BPT	Best Engineering Judgment

The fundamental change incorporated in the 1975 BAT and NSPS concerned a pollutant that BPT had not regulated: heat. The BAT regulations prohibited any discharge of water from recirculating cooling systems at temperatures higher than that of the intake water. Plants with other types of systems (once-through cooling, cooling ponds, or lakes) could discharge heat only if they could demonstrate that they had been in service before the regulations were promulgated. The NSPS standards included a thermal discharge prohibition for all types of cooling systems.

Technologies to meet the additional BAT and NSPS limitations are considerably more complex than those to meet BPT. The more stringent limits on oil and grease in bottom-ash transport water require complex recirculation systems, the zero-discharge limit for fly-ash transport water at new plants calls for dry fly-ash handling (which for a new plant is no more expensive than wet handling), and thermal discharge limits in most cases require highly effective recirculating cooling systems.

1977 Pretreatment Standards

In 1977 EPA promulgated pretreatment standards for the few systems that discharge to publicly owned treatment works (POTWs). The basic principle of pretreatment standards was that pollutants that interfered with or passed through the operations of a POTW were to be controlled. Applied to electric utility discharges, this principle meant that pretreatment standards were equivalent to or less stringent than BAT or NSPS. Chlorine and oil and grease were not controlled by pretreatment standards because these pollutants could be removed by POTWs, but limits for metals were the same as those for BAT and NSPS. Pretreatment standards did not apply to thermal discharges.

Recent Developments Affecting the Effluent Guidelines

Several major developments since 1976 have altered water pollution control regulations for the electric utility industry. In July 1976, as a result of a suit brought by Appalachian Power Co., the U.S. Court of Appeals remanded to EPA the 1975 BAT and NSPS standards governing thermal discharges. Less important aspects of the 1975 regulations also remanded by Appalachian Power included the NSPS zero-discharge limit for fly-ash transport water and limits on runoff discharges.

At approximately the time of the Appalachian Power decision, the Agency signed a consent decree settling another case brought against it by the Natural Resources Defense Council (NRDC). In essence, as applied to electric utility discharges, the NRDC consent decree: (1) committed the Agency to a schedule for promulgating effluent limitation guidelines for point source categories (electric utilities were the second of 21 categories); and (2) specified 65 toxic pollutants, subsequently extended to 129 priority pollutants, that were expressly to be considered in the development of effluent limitation guidelines.

In 1977 Congress amended the Clean Water Act, incorporating the major provisions of the consent decree. The Clean Water Act amendments extended the BAT compliance date from July 1983 to July 1984, but considerably increased the scope of BAT and NSPS, reiterating the consent decree's directive that standards be set for toxic pollutants.

1980 Proposed Effluent Limitation Guidelines

In October 1980, the Agency proposed new effluent limitation guidelines for the electric utility industry required by the Clean Water Act, after the consent decree was incorporated into the Act by the 1977 amendments. Major changes from BPT standards in the proposed regulations were (1) an absolute prohibition of discharges containing the 129 priority pollutants, (2) a reduction in allowable chlorine discharges from plant cooling systems, and (3) reinstitution for new plants only of the standards for the zero discharge of fly-ash transport water, which the Court of Appeals remanded in 1976. (Runoff standards also remanded by the court had been reinstituted earlier in 1980 by an agreement between industry and the Agency.)

The 1980 proposed effluent limitation guidelines were perhaps more significant for what they did not propose than for what they did propose (see Table II-1). No controls beyond those required by BPT were required for bottom-ash transport water at existing plants. This rescinded the 1975 BAT limitation of permissible discharges to levels below those allowed under BPT. In addition although wash waters from flue-gas desulfurization were included under low-volume waste, the Agency asserted that it was reserving consideration of specific standards for this waste stream.

The 1980 proposed regulations also did not reinstitute the thermal regulation that had been remanded in 1976. In the absence of federal guidelines, individual permit writers apply in each case "best engineering judgment" (BEJ) to implement the Clean Water Act's restrictions on environmental damage from thermal discharges. Of course, individual states may impose further limitations.

Cooling Water Intake Standards

In addition to the specific technology-based effluent limitations under Section 301 of the Clean Water Act, Section 316(b) requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." In 1976 the Agency promulgated regulations implementing this section which required case-by-case examinations of the environmental effectiveness and economics of cooling-water intake structures. This way EPA could determine the best (i.e., most effective) structure whose cost was not "wholly out of proportion to the magnitude of the reduction in level of estimated damage." These regulations were remanded in 1977. So, as in the case of thermal discharges, individual permit writers implement the Clean Water Act's provisions by applying case-by-case "best engineering judgment."

Water Quality Effluent Limitations

Section 302 of the Clean Water Act provides that where technology-based standards are insufficient to "assure protection of public water supplies, agricultural and industrial uses, and the protection and propagation of a balanced indigenous population of shellfish, fish, and wildlife and allow recreational activities, effluent limitation . . . shall be established which can reasonably be expected to contribute to the attainment or maintenance of such water quality." Under this requirement applicants for discharge permits must obtain state certification that a discharge will not violate state water quality standards.

REGULATIONS CONTROLLING THE DISPOSAL OF SOLID WASTES

Until recently, how electric utilities have disposed of solid waste has received little attention relative to how they discharge pollution into air and water. Three factors, however, have focused increasing attention on utilities: (1) the increasing stringency of air and water pollution regulations that have led to control techniques that themselves generate solid waste; (2) the possibility that some or all of these wastes may be designated as "hazardous" under the Resource Conservation and Recovery Act (RCRA) and, therefore, will require expensive disposal procedures; and (3) the increasing awareness nationwide of solid waste disposal in the wake of events at Love Canal and elsewhere.

Resource Conservation and Recovery Act and Regulations Implementing the Act

The major federal regulations governing solid waste disposal were mandated by the Resource Conservation and Recovery Act of 1976. Under RCRA, EPA was required to develop an integrated program for managing hazardous and solid wastes. As provided by RCRA, the hazardous waste management aspect of the program would be developed initially by EPA, but authority for implementing it would be delegated subsequently to states with programs equivalent to the federal programs. Programs for managing nonhazardous solid wastes were to be developed by individual states, providing that general minimum guidelines promulgated by EPA were met or exceeded. Solid wastes from electric utilities include: by-products of coal combustion and flue gas cleaning, such as ash and scrubber sludges; chemical wastes from metal cleaning, from degreasing, and from wastewater and makeup water cleaning; and hazardous substances (notably PCBs) contained in electrical equipment such as transformers.[15]

RCRA Section 3004--Hazardous Waste Disposal Regulations

Under RCRA, a waste can be designated as hazardous if: (1) it fails tests specified by EPA for ignitability, corrosivity, reactivity, or toxicity; or (2) it is listed specifically as hazardous. A number of wastes and residues from powerplants--such as metal-cleaning wastes and sludges from chemical waste treatment--may fail one or more of the four

[15]Nuclear plants generate low- and high-grade radioactive wastes; however, the National Regulatory Commission (NRC), rather than EPA, regulates these wastes.

tests, and certain degreasing compounds containing halogenated solvents and PCBs have been listed as hazardous wastes.

Given their relatively small volumes of hazardous waste (assuming ash and scrubber sludge are considered nonhazardous), electric utilities in most cases find it more economical to dispose of their hazardous waste off-site. Requirements for on-site disposers of hazardous wastes are extensive, and economies of scale in meeting these requirements are available only to operators of large facilities.

RCRA requires off-site disposers to determine whether a waste is hazardous and, if so, maintain records concerning its disposition. The major single requirement for off-site disposers is the completion of a manifest, or list, specifying who generated the waste, what kind and quantity of waste was shipped under the manifest, who transported it, and what EPA-approved disposal facility was to receive it. This manifest is used (1) to transfer responsibility for a hazardous waste from the transporter to the disposal facility's operator, and (2) to track the waste through its ultimate disposition. However, RCRA clearly states that the generator has ultimate liability for the long-term integrity of the disposal facility's operations.

RCRA Section 4004--Nonhazardous Waste Disposal Guidelines

Large-volume waste from electric utilities, such as fly and bottom ash and scrubber sludge, are currently treated as nonhazardous wastes under section 4004 of RCRA. These wastes are specifically excluded by statute from the hazardous waste category pending an Agency study of the characteristics of and disposal practices for ash. Though the Agency has not made final decisions concerning disposal requirements for ash and sludge, it is likely that these wastes will continue to be treated as nonhazardous in virtually all areas.

Several important differences exist between RCRA requirements for hazardous and nonhazardous waste disposal. For hazardous waste disposal, EPA develops regulations that the states implement through EPA-approved programs. By contrast, aside from incorporating EPA's minimum criteria for solid waste facilities, the states develop their own regulations for nonhazardous waste.

Since large-volume nonhazardous wastes are likely to be disposed of on-site, electric utilities are directly affected by requirements for the design and operation of nonhazardous waste disposal facilities. The major requirements under EPA's 4004 guidelines for sanitary landfills are protection of:

- Environmentally sensitive areas--flood plains, wetlands, and critical habitats for endangered species;

- The quality of ground water drinking supplies against contamination; and

- Surface waters.[16]

State regulations meeting these guidelines vary, at times significantly, across regions of the country. In some cases, these regulations respond to regional variations in soil permeability, dependence on ground water, or coal-ash characteristics and are necessary to meet EPA guidelines. In other cases, they vary because state attitudes toward ash disposal differ.

A TBS study of fourteen major current and future coal-consuming states reveals two major sources of differences among state regulations governing ash disposal.[17] The first concerns the classification of coal ash: eight of the fourteen states treat coal ash as any other nonhazardous solid waste, four apply more stringent standards for coal ash than for other solid wastes, and two consider ash an "inert nondecomposible" material requiring less careful treatment than other solid wastes. The second difference relates to ground water protection: five states require specific measures, while the remaining states establish requirements case by case. The difference in regulations, coupled with regional variations in ash characteristics and hydrological and geological factors, results in considerable regional specificity in ash-disposal practices and costs.

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[16] Other 4004 requirements--such as daily cover, disease and vector control, and access control--are less relevant to electric utility wastes or are already met by electric utilities.

[17] Temple, Barker & Sloane, Inc., Analysis of Electric Utility and Industrial Boiler Solid Waste Disposal Practices and Costs (draft), for EPA's Energy Policy Division, Office of Policy Analysis, June 1981.

Polychlorinated Biphenyls (PCBs) Interim Control Measures

PCBs pose a somewhat different problem from other solid wastes in that concern exists about both the operation and the disposal of electrical equipment containing or contaminated by PCBs. Disposal of PCBs is difficult because of their extremely hazardous nature and because they do not readily decompose into less hazardous substances. For these reasons PCB disposal in landfills is considered environmentally unsound. Efforts are under way to develop alternative methods of disposing of PCBs. For example, two firms have been authorized to incinerate PCBs at very high temperatures.

While continuing to study the extent and the nature of the PCB problem in cooperation with industry, EPA has established a set of interim measures for inspecting and maintaining electrical transformers containing PCBs.[18] These measures establish strict requirements for operators of transformers located near food and feed products, including conducting weekly inspections, reporting and servicing leaking equipment, and maintaining records of inspections and service. For equipment not near food and feed products, quarterly inspections are required.

INTERACTIONS AMONG ENVIRONMENTAL REGULATIONS

Although environmental programs for air, water, and solid waste are distinct in a regulatory context, they intertwine at individual plants. Air pollutants removed by wet systems to comply with air regulations create waste streams controlled by water regulations, which in turn generate sludges that must be disposed of in compliance with solid waste regulations. This section points out the overlapping coverages of the regulations for air, water, and solid waste described in the previous sections and discusses some of the major cross-media effects.

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[18] Transformers containing PCBs are frequently not on utility property, although the utility owns them.

Overlapping Regulatory Coverages

Regulations affecting a specific plant depend on its fuel type, location, technical configuration, and in-service date.

As shown in Table II-2, coal-burning plants are subject to the full range of air, water, and solid waste regulations. Oil-burning plants are somewhat less affected by air regulations and as a rule do not have either the ash transport streams that constitute a major water problem or the ash and scrubber sludge that contribute to solid-waste disposal concerns. Gas and nuclear plants are affected predominately by water regulations for low-volume streams and cooling water, but not by EPA's air and solid waste regulations. (Nuclear plant emissions are also regulated by Nuclear Regulatory Commission rules not discussed in this chapter.)

Table II-2

POWERPLANT POLLUTION SOURCES
AS A FUNCTION OF PLANT FUEL TYPE

	Coal	Oil	Gas	Nuclear
Air				
SO_2	M	M	0	0
TSP	M	m	0	0
NO_x	M	M	M	0
Water				
Cooling	M	M	M	M
Ash Transport	M	m	0	0
Low-Volume	M	M	M	M
Runoff	M	m	m	m
Solid Waste				
Ash, Scrubber Sludge	M	m	0	0
Chemical	M	M	M	M
PCB	M	M	M	M

M = Major Source
m = Minor Source
0 = None

Plant location also influences the applicability of particular regulations. As noted above, air regulations vary for attainment and nonattainment areas. Within attainment areas, the applicability of Class I and II area PSD limits depends on location. Cross-boundary effects and differing attainment conditions for SO_2 and TSP in the same location can result in complex regulatory requirements for some plants. Location also affects the applicability of water regulations, but only indirectly. For example, in some areas of the country where recirculating cooling systems are more prevalent, plants are subject to standards for these systems. State solid waste regulations implementing federal guidelines vary significantly from state to state, depending on such local conditions as hydrogeology and public attitudes. Consequently location can greatly affect the standards applicable to ash and sludge disposal.

Technical design factors strongly influence the portion of water regulations that apply to particular plants. An example is the distinction between once-through and recirculating systems, which are subject to different chlorine standards under the 1980 proposed effluent limitation guidelines. Another distinction exists between plants with dry-ash handling systems and plants with wet-ash handling systems and the consequent ash transport waste streams. The applicability of air regulations does not vary as a function of plant configuration, but the 1971 and 1979 air NSPS have affected new plant designs by making construction of new cyclone boilers virtually impossible because these boilers cannot be designed to meet NO_x limitations.

As more and more plants come into service under regulatory programs established over the past decade, an increasingly critical factor determining the applicability of environmental regulations to an individual plant will be the date on which the plant "commenced construction."[19] As shown in Figure II-2, whether a plant is subject to specific air emission limitations depends on when construction of the plant began relative to the effective dates of the 1971 and 1979

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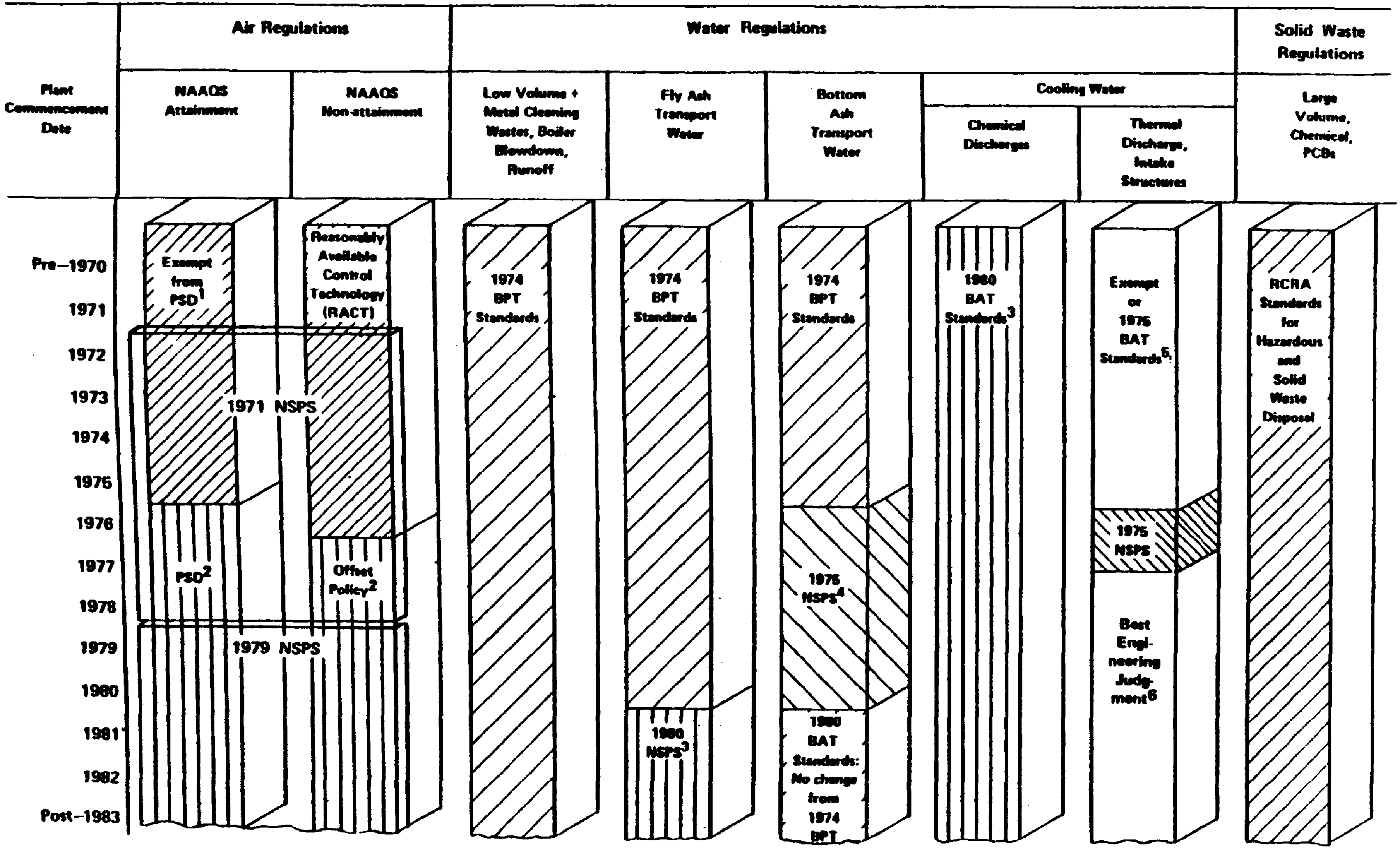
[19]Because of the effect of a plant's commencement date on the applicability of specific regulations, its definition is important. Generally, to claim that it should not be subject to regulation, a plant must demonstrate that before the effective date of the regulation it had (1) received all required permits and (2) either commenced on-site construction or established binding agreements for the plant's completion.

Figure II–2

APPLICABILITY OF ENVIRONMENTAL REGULATIONS TO EXISTING AND NEW ELECTRIC UTILITY PLANTS



[1]Plants in some areas may be subject to BART visibility requirements.

[2]PSD and Offset Policies were revised in 1977 and 1978, respectively.

[3]Proposed regulations.

[4]1975 BAT and NSPS for bottom ash transport water rescinded by 1980 NSPS, which are equivalent to 1974 BPT.

[5]1975 Thermal Standards apply to recirculating cooling systems only; other systems exempt.

[6]Regulations on intake structures and thermal discharges remanded in 1976 and 1977, respectively. No new regulations promulgated; therefore, permit writers apply case by case "best engineering judgment."

NSPS air regulations. It also depends on the PSD and offset regulations for attainment and nonattainment areas, respectively, that were in force when it received its construction permit. In general, because NSPS for water pollution control have reiterated existing plant requirements, a plant's commencement date is a less important factor in determining water regulations applicable to it. Two exceptions concern fly-ash transport water, for which a zero-discharge standard was proposed in 1980, and bottom-ash transport water, for which the NSPS promulgated in 1975 were rescinded in 1980 in favor of the 1974 BPT standards. Federal solid and hazardous waste regulations do not differentiate between new and existing facilities; however, individual state solid waste regulations may impose more stringent requirements or differentiate between existing and new facilities.

Cross-Media Effects

The cross-media effects associated with environmental regulations relate primarily to more stringent air regulations, which in turn have resulted in greater water pollution control and solid waste disposal burdens. State implementation plans to meet the NAAQS and the 1971 NSPS air regulations required fly-ash collection systems with greatly increased efficiencies. To the extent that wet-ash transport systems have been used to sluice ash from these systems, utilities have needed to comply with additional water pollution regulations. In fact, concern over water pollution control requirements has fostered a trend toward dry-ash handling.

The 1971 NSPS air regulations effectively require scrubbers for plants not using low-sulfur coal, and the 1979 NSPS require these systems at all new plants. In addition, SIPs may in effect require scrubbers at existing plants. As has been noted, the Agency has not determined how to handle wastewater from wet scrubber systems. The solid-waste disposal problems posed by scrubber sludges, however, are significant. These sludges increase the quantity of wastes to be disposed of and generally require some form of stabilization or chemical fixation before disposal.

Some water pollution control measures may also result in relatively small volumes of solid waste that require disposal as hazardous wastes. Public comments concerning the 1980 proposed effluent limitation guidelines have argued that stringent application of these guidelines to metal-cleaning and low-volume wastes may result in sludges that qualify as hazardous wastes. Since low-volume waste streams are often intermingled, utilities may face the problem of either instituting changes to segregate waste streams that do and do not generate hazardous sludges or disposing of larger quantities of sludge in facilities that meet the criteria for disposing of hazardous waste.

III. CASE STUDIES

CHAPTER III

THE EFFECTS OF ENVIRONMENTAL REGULATIONS ON THE OPERATIONS AND PLANS OF ELECTRIC UTILITIES

CONTENTS

CONTENTS
(continued)

III. THE EFFECTS OF ENVIRONMENTAL REGULATIONS ON THE OPERATIONS AND PLANS OF ELECTRIC UTILITIES

INTRODUCTION AND MAJOR FINDINGS

This chapter reviews the effects of environmental regulations on the operations and plans of electric utilities and sets environmental considerations into the context of the industry's overall business environment. During the last decade, a large number of changes have occurred in the overall business environment of utilities. On balance, the changes greatly increased the complexity, uncertainty, and financial difficulties associated with utility operations and plans. An important element in the changed business climate of utilities has been the marked increase in the scope and complexity of environmental regulations.

In response to heightened uncertainties and increased costs, utilities have adopted strategies designed to reduce their risk exposure and to alleviate their financial difficulties. To forestall further financial deterioration, utilities have sought frequent rate increases to recover as quickly as possible increases in operating and capital costs. Because of their financial constraints, many utilities have also placed increased emphasis on less capital-intensive alternatives and methods for reducing the need for new capacity. The prospect of greater uncertainty without commensurate earnings in the regulated electric utility sector has also prompted some companies to diversify into nonregulated business, and many utilities are considering similar strategies.

Environmental regulations emerging during the 1970s--covering air, water, and solid wastes--have introduced both additional uncertainty and higher costs in the siting, planning, construction, and operation of utility powerplants. Given the other difficulties affecting electric utilities, the uncertainties and costs associated with environmental regulations are having an increasingly important effect on utility operations and plans. Perhaps not surprisingly, utilities have developed plans and taken actions to reduce the costs and uncertainty associated with environmental regulations.

To understand how utilities have responded and are planning to respond to changes in their business environment, and to determine the implications of these responses for compliance with environmental regulations, TBS conducted case studies of six electric utilities. Each case study involved a series of interviews with company executives and technical staff. These were supplemented with interviews with other knowledgeable individuals in other utility companies and an industry association.

The objective of the case studies was to identify both the direct and the indirect effects and costs of environmental regulations on utility operations and plans. The research was intended first to describe obvious, direct effects such as the installation of pollution control equipment or a switch to low-sulfur fuels. TBS's research was also intended to identify and discuss any subtle, indirect costs of environmental regulations--such as additional technological uncertainty or reduced plant reliability--that increase costs, but that are not highlighted in the usual utility financial reports or in the engineering cost estimates that form the basis for the quantitative analysis in subsequent chapters. The case studies also were intended to provide EPA with candid reactions of utility executives and technical staff to environmental regulations and to highlight differences of opinion among utilities and between utilities and EPA.

Interviews with the case study companies uncovered four major conclusions regarding their compliance activities associated with existing powerplants. First, the expense and difficulty of achieving compliance at existing powerplants varies greatly among utilities and appears to be a function primarily of the ambient air quality near powerplants, the types of fuel consumed, and the stringency of state implementation plans. Second, as is corroborated by the quantitative unit-level analysis discussed in Chapter IV, utilities have complied with the most costly regulations--those related to sulfur dioxide--primarily by increasing the quality of their fuels rather than by installing equipment. Third, utilities fully accept their responsibility to monitor pollutant emissions and report violations accurately to EPA or state environmental agencies. Finally, to reduce capital and operating costs, utilities have usually sought to reduce the stringency of regulations they must meet through negotiation or litigation.

Our interviews also revealed a pervasive concern that financial considerations will become more influential in utility decision making and will hamper the ability and willingness of utilities to meet the capital requirements associated with capacity expansion and pollution control. The full impact of the industry's current weak financial condition has not yet been felt, in part because load growth since 1974 has fallen dramatically. Many utilities have continued the construction of powerplants already under way before the falloff in growth became apparent, but they have been able to pare back other construction programs and lower their long-run financing requirements. However, when future growth in demand requires new capacity to be added, the large capital requirements associated with building new coal-fired powerplants may be an obstacle for financially weak utilities. Perhaps as important, even utilities that have relatively high bond ratings will be reluctant to make investments that require the issuance of additional common stock if they expect future earnings to be inadequate. To the extent that environmental regulations contribute to the capital and operating costs of new capacity, both utilities and consumers may attempt to modify environmental requirements in an attempt to lower electricity costs and to avoid reductions in service reliability.

While some case study companies with relatively good ambient air quality are not greatly concerned with prevention of significant deterioration (PSD) regulations, other companies stated that, even in the absence of financial constraints, existing air environmental regulations will all but eliminate their ability to site coal-fired powerplants in the future. These companies are convinced that existing PSD regulations are unworkable and are actively working to secure passage of legislation to revise them. These utilities believe that PSD increments will be exhausted over time and that the utilities will be required to obtain offsets--which may be costly or unavailable at any price. These beliefs are a point of contention with various environmental officials.

To avoid or to mitigate the financial and environmental difficulties associated with siting, building, and operating new coal-fired powerplants, the majority of the case study utilities are actively pursuing other capacity alternatives. For example, some companies are exploring the use of synthetic fuels to supplement or displace oil and natural gas. Utilities also are reconsidering historical standards of reliability with an eye toward lowering such standards and thereby slowing the rate at which new capacity needs to be added. Some of the companies studied are actively considering purchasing power to meet future demand, attempting thereby to export both some environmental and financial problems. Several of the companies are actively exploring greater use of unconventional sources of power, such as the sun, the wind, and wood, and are currently planning on them to contribute to future electricity supply. However, reflecting the technological uncertainty associated with these sources, these companies have contingency plans that involve more traditional sources of supply, such as new coal-fired powerplants.

As an alternative to building new capacity, all the case study companies are evaluating, and some are aggressively pursuing, direct load controls, conservation programs, and new pricing structures such as time-of-day rates. The attractiveness of these alternatives depends on situational factors. Companies that currently have ample capacity tend to prefer not to restrict demand. Other companies facing the prospect of having to build new powerplants may vigorously try to hold down demand but be unable to find cost-effective ways for doing so.

While environmental considerations may not have been the major factor in shaping the plans of the case study utilities, environmental regulations have presented them with significant challenges. Environmental regulations have increased the lead time for new powerplants and have increased the uncertainty associated with meeting all necessary permitting and licensing requirements.

Technology-forcing regulations, such as best available control technology (BACT) and lowest achievable emission rate (LAER), also have increased the technological risk perceived by utilities. Some of these regulations require state-of-the-art pollution control equipment that may not perform well enough to achieve compliance and may adversely affect a plant's performance. The utilities interviewed believe that the technology-forcing approach to environmental control is undesirable because it may preclude the use of more certain and cost-effective ways to control pollutants. Utilities strongly prefer to be given performance standards, but to be allowed to choose the best method for complying with them. The case study companies also expressed concern that, as new technologies are introduced, BACT and LAER standards will change, thereby creating additional uncertainty and higher costs.

Utilities have responded to the challenges presented by environmental regulations in several ways. First, they have made their environmental affairs departments an important element in the utility planning process. These departments are typically responsible for gathering and assessing information on regulatory requirements, costs, and risks and for trying to anticipate changes in environmental regulations. The departments attempt to reduce the potential adverse consequences of uncertainty about regulations by identifying key environmental issues, preparing contingency plans, and attempting to maintain as much flexibility as possible in the utilities' supply plans. Utilities also have supported lobbying efforts to change requirements from a technology-forcing orientation to an approach that focuses on meeting pollutant-loading goals. Finally, utilities have initiated research and development activities that contribute significantly to their ability to meet existing requirements in a cost-effective manner and that develop technical expertise that can be used to support negotiations and, when necessary, litigation.

RESEARCH METHODOLOGY

Six case studies were conducted to gather in-depth information on the effects of environmental regulations on utility operations and plans. Each case study comprised on-site interviews of a utility's management and staff in a number of functional areas, including finance, capacity planning, powerplant operations, engineering, and environmental affairs; a review of public and internal company documents relating to the company's business operations and environmental activities; and on-site interviews of state public utility commissions (PUCs) and state environmental and siting agencies. The case studies were supplemented with interviews with environmental experts in an industry association, regional EPA staff members, and other utility executives.

TBS informed the case study companies that their identities would be kept confidential to enable them to be complete and candid in their responses. Therefore, to preserve confidentiality, this chapter does not provide detailed information that would associate responses with a particular company.

The case studies were conducted in five regions of the United States to reflect the broad range of business situations and environmental concerns characteristic of the electric utility industry. The companies were selected to provide diversity along a number of dimensions, including: demand growth, existing capacity fuel mix, financial condition, and existing air quality. This diversity ensured that a wide variety of the major topics of environmental interest were faced by one or more of the case study companies. These topics include: compliance strategies for existing powerplants of all the major fuel types; oil-to-coal conversions; PSD, nonattainment, and visibility regulations; and the siting of new powerplants. Of course, despite the diversity of the case study situations, six case studies cannot be viewed as capturing the full range of responses to environmental regulations in the electric utility industry.

THE BUSINESS ENVIRONMENT OF ELECTRIC UTILITIES

To provide the background necessary for an understanding of electric utility decision making and actions vis-a-vis environmental regulations, this section reviews the most important influences on electric utilities and discusses how changes in those factors have affected and will affect utility decision making. The considerations influencing utility investment decisions and strategies for compliance with environmental regulations include: the objectives, rate regulatory environment, and financial condition of utilities; federal and state energy regulation; and the market for electricity.

The Objectives, Rate Regulatory Environment, and Financial Condition of Utilities

A utility's objectives typically are to provide adequate and reliable electric service at reasonable cost to its customers, to provide a reasonable rate of return to its investors, and to comply with societal objectives and regulations. Differences in the interests of consumers, investors, and society can result in conflicts between utility objectives and therefore can require utilities and their regulatory commissions to make tradeoffs between objectives. For example, consumers' rates can be reduced by allowing the reliability of electric service to deteriorate or by lessening the stringency of environmental controls. A balancing of objectives requires a consideration of the effects of decisions not only on current consumers, but also on future consumers. For example, decisions to lower returns to investors may result in lower rates for consumers in the short run, but may lead to higher costs for future consumers.

Because utilities are monopolies, state (and to a lesser degree, federal) commissions have historically been given the regulatory authority to ensure that utilities do not exploit their monopolistic power. Regulatory commissions exercise their authority by regulating the level and structure of a company's rates which, in turn, are key determinants of a utility's revenues. The appropriate level of revenues is commonly interpreted as the level that allows a company to serve its customers and to provide its shareholders with an opportunity to earn returns commensurate with those available on investments of comparable risk.

A fundamental regulatory problem is that PUCs tend to determine rates on the basis of procedures that do not accurately reflect costs during the period in which the rates are in effect. In an inflationary environment, these procedures have generally resulted in electric rates that have been inadequate to cover costs and to provide an acceptable rate of return. As a result, in the last decade, most major electric utilities have persistently failed to earn rates of return consistent with those required by investors in common stock.

There is also considerable debate about whether PUCs adequately adjust allowed returns to correspond to the risks of particular projects, a debate with obvious implications for the willingness of utilities to invest in state-of-the-art technologies. Utilities are concerned that PUCs will not reward their stockholders for the successful undertaking of risky projects, but will force them to bear most of the unfavorable consequences of an unsuccessful outcome. If an economically attractive but risky project proves successful, the PUC can hold the utility's rate of return constant and pass on the economic benefits to consumers in the form of rates lower than they otherwise would have been. If the project proves to be unsuccessful, the PUC can reject it as an allowable component of the cost of service, thereby reducing the rates of return realized by company investors.

Mainly because of inadequate returns, the financial health of the electric utility industry has declined precipitously over the last decade and, as a result, many utilities have become unable or reluctant to undertake new financings. Inadequate returns have contributed to a general decline in electric utility bond ratings, an important determinant of a company's cost of debt and ability to access the credit markets. From 1975 to 1979, Moody's Investor Service, a major bond rating agency, lowered utility bond ratings 41 times while only raising utility bond ratings 17 times. Insufficient returns have also resulted in common stock market price to book value ratios (MBRs) of less than one for almost all utilities. For example, in early May 1981, 97 of the 100 utilities included in Salomon Brothers' utility common stock studies had MBRs of less than one. An MBR of less than one means that sales of new common shares dilute the common stock book value per share and tend to depress earnings per share, dividends per share, and the market price per share. Thus, existing shareholders in companies with MBRs of less than one tend to resist the issuance of common stock--and investments necessitating such issues.

In response to inadequate rates of return and their strained financial condition, utilities have aggressively been seeking higher rates from their PUCs and some utilities have diversified into unregulated businesses. Utilities are filing for rate increases more frequently and are requesting higher allowed rates of return. However, several of the utilities studied are pessimistic about the chances of attaining adequate rates of return and improving their financial health. This lack of optimism stems from the intense pressure on PUCs to insulate consumers from the enormous increases in fuel, construction, and debt and equity financing costs during the last decade. In an attempt to improve their profitability, some utilities have also diversified into unregulated businesses and many utilities are considering doing so. However, diversification into businesses other than the production and transmission of electricity may be precluded for some utilities by the Public Utility Holding Company Act. PUCs can also influence utility diversification activities through the ratemaking process. Moreover, many utilities are concerned that PUCs may use unregulated profits to subsidize electric rates, thereby reducing the potential gains from diversification.

The prospect of continuing financial strains and inadequate returns has led most of the case study utilities to place increased emphasis on the capital cost of a project. This emphasis has led electric utility managements to explore alternatives that reduce the need for additional capacity, to select less capital-intensive methods for meeting particular needs, and to resist environmental regulations that require large capital outlays. Examples of alternatives that reduce or defer the need for building new capacity include: purchasing power instead of building new capacity, extending the operating lives of existing powerplants, adopting conservation programs to reduce the need for new capacity, and relaxing reliability criteria relative to historical levels.

The increased weight accorded to capital spending requirements may result in the selection of alternatives that have higher long-run costs for consumers than more capital-intensive alternatives. For example, a company may not be willing or able to convert an existing oil-fired generating unit to coal, even though the conversion would result in lower costs to consumers, if it cannot get adequate returns on the required capital investment or if it cannot raise capital. Similarly, purchases of power, while avoiding capital costs, may be more expensive for consumers than the construction of new powerplants. The ability of utilities to avoid capital costs, while passing along fuel and purchased power costs to consumers via automatic fuel adjustment clauses, is by no means unconstrained. PUCs can identify opportunities for utilities to lower future costs and can employ blandishments or threats, or both, in rate cases to enable and motivate utilities to undertake such investments.

Although favorable financing, tax, and regulatory rules for pollution control equipment can mitigate many of the adverse effects of such equipment on a utility's financial condition, they do not fully eliminate the bias against capital investment when returns on investment are insufficient. For example, some pollution control equipment can be financed using tax-exempt debt financing (industrial revenue bonds) issued by municipal authorities. However, because the pollution control bonds are backed by the credit of the utility (and typically carry a lower bond quality rating than the utility's other bonds because they have lower priority than first mortgage debt), they cannot always be issued by utilities having a weak credit rating. Moreover, even if pollution control financing is available, the lower cost of such debt, while improving a utility's interest coverage ratios, produces interest savings that are passed on to consumers and not retained by investors. As another example of an attempt to alleviate financing problems, many PUCs and the Federal Energy Regulatory Commission allow more favorable accounting treatments for pollution control equipment than for other utility expenditures, e.g., by including capital expenditures for pollution control in the rate base during construction. Many PUCs also permit normalization accounting for various tax expenses associated with pollution control equipment, even when they do not generally allow normalization for other types of expenditures. These approaches can improve a utility's financial condition by increasing internal cash flow. The improvement in financial condition tends to reduce the riskiness of earnings but does not increase the level of earnings and, consequently, may not entirely eliminate any existing bias against capital-intensive investment decisions.

The rate regulatory environment and the financial condition of electric utilities have important implications for utilities' responses to environmental regulations. The rapid rate of increase in environmental and non-environmental costs in the last decade has intensified utilities' resistance to more stringent environmental regulations. Reflecting their objective of providing low-cost service to their customers and reasonable rates of return to their investors, utilities tend to resist costly environmental requirements just as they try to control other cost increases--such as increased fuel prices, higher construction costs, and higher wage rates. Moreover, given the public and political pressures on PUCs to try to hold costs down, increases in cost may not be covered by increases in rates, adding to the utilities' difficulties in providing an adequate rate of return to investors. To help alleviate these problems, utilities resist costly environmental regulations, especially those having large capital costs.

Federal and State Energy Regulation

In recent years the scope of federal and state energy regulation has increased dramatically, further constraining electric utilities in their choices as to the amounts, types, and locations of powerplants. Reflecting the federal government's desire to reduce reliance on foreign oil, the Powerplant and Industrial Fuel Use Act (FUA) was passed in 1978. FUA has effectively eliminated new oil- and gas-fired units as an alternative for new baseload capacity, restricted the use of gas prior to 1990, and prohibited the use of gas in existing baseload units after 1990. FUA also authorizes the Department of Energy (DOE) to prohibit the use of oil and gas in certain existing oil- and gas-fired units. Even without the statutory limitations imposed by FUA on the use of oil and gas as boiler fuels, the current high cost of oil and gas makes them economically unattractive as fuels for new baseload powerplants compared with, for example, coal-fired powerplants.

Federal action and inaction have also helped remove nuclear powerplants as an alternative for capacity expansion. Increasing concern over the safety of nuclear powerplants and the disposal of nuclear wastes over the last ten years introduced uncertainties that are so great that few, if any, utilities believe new nuclear powerplants to be a viable capacity expansion option before the 1990s. Regulatory requirements have become increasingly stringent over the last decade and are viewed by utilities as likely to become even more stringent as a result of the accident at Three Mile Island. The resultant tightening of regulatory requirements increases the cost of complying with safety requirements, introduces the possibility of unknown but potentially costly design modifications, and increases the possibility of costly delays in licensing and constructing new facilities. Perhaps even more important, obtaining public acceptance of sites for new nuclear powerplants, while difficult before, is likely to become even more difficult. The lack of a federal program for disposing of nuclear wastes introduces further uncertainty as to the ultimate cost of nuclear power.

In addition to increased federal constraints on utility actions, some state regulatory agencies have also introduced further constraints by becoming more directly involved in utility investment and operating decisions. In recent years, a number of PUCs and state siting agencies have sought to encourage investment in unconventional energy sources, the conversion of oil- and gas-fired units to coal, and the institution of conservation programs. Some have also sought to discourage the development of certain types of capacity such as nuclear powerplants. PUCs often have the authority to certify utility proposals for new powerplants and can influence utility investment plans by delaying or denying certification of projects. PUCs can also influence utility decisions through their ratemaking authority. For example, one PUC explicitly ties utility rates to the achievement of conservation goals. Similarly, in a number of states, siting agencies have the authority to approve powerplant sites and thereby can affect a utility's investment plans. Criteria used by PUCs and siting agencies to evaluate utility proposals generally include the need for a new powerplant, environmental impact, compliance with laws and regulations, and such social goals as oil displacement and conservation.

Market Uncertainties

Utility investment decisions also have been importantly influenced by uncertainties associated with forecasting the demand for electricity, the cost of oil, and the rate of inflation. In attempting to provide adequate service at reasonable costs to future consumers, utilities have to project the need for generating capacity 10 to 15 years in the future because of the increasingly long lags involved in the site selection, permitting, design, and construction of a new powerplant. Unfortunately, coincident with the increase in the length and uncertainty of construction lead times, increased difficulties in forecasting demand have arisen. Since the mid-1970s, the growth in demand for electricity has sharply declined in amount and has greatly increased in uncertainty. Steep rises in oil and other operating and construction costs in the last decade have resulted in rapid increases in the price of electricity. Customers have responded by cutting their usage and doubtless will continue to respond, but in ways that are still hard to predict. In addition to reducing their energy usage, customers may increasingly turn to natural gas or, especially in the case of larger customers, turn to unconventional energy sources and cogeneration projects.

The recent declines in demand have led to an excess of total industry capacity, although much of the apparent excess capacity in many regions is oil-fired and has been rendered economically obsolete by the spectacular increase in oil prices since 1973. As a result of the decline in demand growth, the financial difficulties of many utilities will be reduced over time because the need for new capacity is reduced. However, in many instances it is more economical to complete new capacity under construction than to cancel or delay it, so that many companies will continue to face high near-term external financing requirements.

The changing patterns of demand have also increased the risks faced by some utilities. There have been several recent instances where PUCs have questioned whether consumers should bear the costs of facilities cancelled due to the drop in demand. Moreover, utilities that delay the operational date of powerplants already substantially completed may also face significant financial strains because consumers usually do not contribute to the financial carrying costs of construction work in progress (CWIP).

In addition to the uncertainties in forecasting demand, utilities' investment decisions are further complicated by uncertainty in future energy prices and the general rate of inflation. For example, the economics of converting existing powerplants from oil to coal are critically dependent on future oil prices which, in turn, are extremely difficult to predict. The general increase in price levels over the last decade not only has contributed importantly to the deterioration of the electric utility industry's financial condition, but also has introduced additional uncertainty in the planning, financing, building, and operating of new powerplants.

The increased uncertainties in forecasting demand, oil prices, and inflation--and PUC response to some of the attendant consequences--obviously exacerbate the difficulties involved in complying with environmental regulations. In an era where forecasting is particularly difficult, utilities naturally do not welcome the time lags and uncertainties in the lead times for new powerplants introduced by environmental regulations.

EFFECTS OF ENVIRONMENTAL REGULATIONS ON EXISTING POWERPLANTS

Environmental regulations affect existing powerplants directly by requiring more pollution control equipment or higher quality fuels than utilities would install or use in the absence of regulations and indirectly by influencing the economics of different operating lives of powerplants and of conversions of oil- and gas-fired powerplants to coal. This section first reviews the ways in which utilities have achieved compliance at existing powerplants, the costs and problems associated with compliance to date, and possible future compliance problems. It then discusses the influence of environmental regulations on utility decisions about the operating lives of existing powerplants and the environmental issues associated with different powerplant lives. Finally, the section reviews the impact of environmental regulations on the oil displacement activities of the case study companies.

Compliance at Existing Powerplants

Four general conclusions regarding compliance activities for existing powerplants emerged from interviews with the case study utilities. First, the expense and difficulty of achieving compliance at existing powerplants varies greatly among utilities and appears to be a function primarily of the ambient air quality near the powerplants, the stringency of the applicable state implementation plans, the type of fuel consumed by the powerplants, and the local cost premiums for low-sulfur fuels. Second, as is corroborated quantitatively in Chapter IV, utilities have complied with the most costly regulations--those related to sulfur dioxide (SO_2)--primarily by increasing the quality of their fuels rather than by installing equipment. Third, utilities fully accept their responsibilities to monitor pollutant emissions and report violations accurately to EPA or state environmental agencies. Lastly, in order to minimize additional capital and operating costs, utilities seek to reduce the stringency of the regulations they have to meet, especially when those regulations require state-of-the-art equipment or when they are thought to be poorly formulated or costly relative to their benefits. Some utilities that face nonattainment air quality problems assert that the cost of complying with stringent regulations is sometimes so large that they effectively have no choice but to resist the regulations to protect the interests of their shareholders and customers.

In comparison with the other utilities, one case study utility has more willingly sought to comply with environmental regulations and to operate units as cleanly as reasonably possible. The company recognizes that its willingness to comply leads to higher consumer costs, but adopted this approach primarily because it reflected the desires of citizens and state regulators to protect scarce water supplies and striking scenic vistas. The company was able to take this approach in part because its rate regulatory environment allowed it to meet its environmental objectives without seriously compromising the interests of its investors or jeopardizing its capacity expansion plans. Company officials and state regulators believe that the company's efforts to control pollution and avoid conflicts with regulators is also a good business policy. The company's willingness to comply has resulted in a good working relationship between the company and its state environmental regulators and has prompted these regulators to permit emission variances or relax standards when the company encountered significant design or operating problems with pollution control equipment.

A detailed discussion of the compliance approaches adopted by the case study utilities, and the costs and problems associated with these approaches, is presented below. The discussion is organized by the four major pollutants subject to emission limits: SO_2, nitrogen oxides (NO_x), particulates, and water pollutants.

Sulfur Dioxide

Compliance with SO_2 regulations can be achieved through using low-sulfur fuel oil and coals, by installing flue gas desulfurization (FGD) systems (often called "scrubbers"), or both. Either method can significantly increase generating costs because low-sulfur fuels command a price premium and scrubbers entail capital and operating costs. If both methods are used, there is a tradeoff between the sulfur content of the fuel and the percentage of SO_2 in the flue gas that must be removed. For example, to meet a given SO_2 standard, low-sulfur fuels require less effective, and therefore less costly, scrubbing systems than high-sulfur fuels.

As noted above, the case study companies for the most part complied with SO_2 regulations for existing powerplants by switching to lower sulfur fuels. They have generally regarded scrubbers as a compliance method of last resort because the incremental cost of lower sulfur fuels has been outweighed by the decreases in powerplant reliability and efficiency and by increases in capital, fuel, other operations, maintenance, and sludge disposal costs that are due to scrubbers.

In isolated instances, scrubbers are the only way or the most economical way for existing plants to comply with SO_2 regulations. One case study company installed scrubbers because it had a favorable contract for high-sulfur coal that made it more economic to install the scrubbers. This company also noted that another company, one not included in the case studies, may in the future be forced to install scrubbers on some of its existing oil-fired powerplants because fuel oil with a sulfur content low enough to meet stringent SO_2 standards being considered by a local environmental authority is generally not available. Another case study company installed scrubbers in its coal-fired units, mainly as original equipment, to meet a state requirement for scrubbers.

The latter company's experience tends to confirm some of the other companies' concerns about FGD systems. Although the scrubbers were designed to achieve removal efficiencies in excess of environmental requirements, the advanced design of the scrubbers has led to operating and design problems and to actual removal efficiencies below the original state standards. The company has successfully negotiated with environmental regulators to resolve many of these problems. Because the company approach to environmental regulations is viewed as positive, its regulators have agreed to significant delays in the design and construction of scrubber modules. Moreover, the company was allowed a relaxation of sulfur dioxide standards after its installed equipment could not continuously meet the original standards. Largely because this company's regulators have permitted variances and allowed the company to operate units while repairing scrubbers, scrubber reliability problems have not significantly affected the reliability of the company's generating units.

Achieving compliance with SO_2 regulations by switching to higher quality fuels requires careful control of the fuel's sulfur content. The variation in sulfur content, especially for coal where sulfur content can vary substantially within a mine, can create compliance problems because emission standards are based on time periods (averaging times) often as short as one day, and sometimes less. If a quantity of fuel with significantly above-average sulfur content is burned for a large portion of the averaging time, an emission violation can occur.

Utilities usually try to deal with sulfur variability and potential emission violations by specifying maximum sulfur contents in their contracts with suppliers. To reduce the risk of poor performance by coal suppliers, some companies routinely inspect the suppliers' coal mines prior to signing a contract, test coal samples before and after shipment, and often use trial contracts to confirm the ability of a supplier to meet contract specifications. To meet coal specifications, suppliers--including those mines owned by the utilities--will often blend high- and low-sulfur coals and in some cases will physically clean high-sulfur coal. In deciding whether to purchase low- or high-sulfur coal, the lower purchase cost of high-sulfur coal must be weighed against the cost of cleaning.

Nitrogen Oxides

The costs of controlling NO_x emissions for existing powerplants generally have been small because they can usually be controlled by relatively inexpensive changes in burner and boiler designs. One of the case study companies--even though located in a state with numerous Class I PSD areas, excellent air quality, and relatively stringent state standards--achieved compliance through burner design changes and by cycling combustion gases to the boiler. However, where NO_x emissions have caused relatively severe air problems, utilities have had to resort to dispatching powerplants on the basis of NO_x emissions during periods of high ambient air NO_x concentrations. Dispatching to control NO_x may increase a utility's total annual energy costs if it increases the loading of less efficient powerplants.

A possible future tightening of NO_x emission standards by some states is of significant concern to some utilities because a further tightening of standards could require the installation of expensive, and as yet not commercially proven, catalytic reduction systems. At least one state faced with poor ambient air quality has already attempted to require powerplants in some localities to reduce NO_x emissions below reductions already achieved through changes in burner design. A number of utilities have taken legal actions to preclude tightening NO_x standards. Utilities have argued that the need for further reductions in NO_x emissions has not been adequately demonstrated and the impact of further reductions on the emission of other pollutants has not been studied. Moreover, one utility indicated that some proposed visibility regulations would require stringent control of NO_x emissions and would, if promulgated, impose such costs that a number of utilities would have little recourse other than to initiate legal challenges to the regulations. It was also noted that many utilities may be more inclined to contest visibility regulations than other regulations because visibility regulations are based on aesthetics, rather than health effects.

Other utilities do not anticipate a tightening of NO_x emission standards either because of new state initiatives or because of existing federal visibility requirements in their service territories. Although the cause of visibility problems is subject to considerable debate, one company stated that it does not believe that NO_x emissions from powerplants contribute significantly to visibility problems in its state. Furthermore, it believes that methods of NO_x control, other than burner and boiler design changes, simply are not available at any reasonable cost and, as a result, will not be required.

Particulates

Particulate emissions can be controlled by limiting the ash content of the oil or coal being burned or by installing an electrostatic precipitator, baghouse, or mechanical collector. In designing compliance strategies, utilities consider the tradeoff between the costs of fuels with alternative ash and sulfur contents and the removal efficiencies and costs of equipment. A number of case study companies noted that the performance of precipitators declines with decreasing amounts of SO_2 in effluent streams. According to these sources, the use of low-sulfur fuels or scrubbing systems to control SO_2 emissions necessitates the use of high-performance precipitators or baghouses or, where possible, the routing of effluent streams through precipitators before scrubbing. However, one case study company questioned the practical importance of the interactions of total suspended particulates (TSP) and FGD systems. According to this company, the interactions of precipitators and scrubbers are not a significant problem for most existing powerplants and should be no problem for new powerplants.

The case study companies expressed no great concern over the requirements for controlling particulates at oil-fired powerplants. This attitude reflects the relatively low levels of cost and technological problems associated with controlling particulates from oil-fired powerplants, compared with those for SO_2 and for particulates from coal-fired powerplants. The case study utilities' compliance strategies generally involve switching to higher quality fuels, although one company also reduced the output range of one of its powerplants and another company installed a precipitator on an oil-fired unit to achieve compliance.

Particulate emissions represent a greater problem at coal-fired powerplants because of the high percentage of ash in most coals. One case study utility installed electrostatic precipitators as original equipment at each of its coal-fired units to meet state particulate regulations, which were somewhat more stringent than federal regulations. Another case study utility had to retrofit precipitators at a number of its major coal-fired units to meet state implementation plans (SIPs) promulgated pursuant to federal legislation. The companies also noted that other utilities have been required to add precipitators to oil-fired powerplants that have been converted to coal.

A number of utilities expressed particular concern about the costs of a tightening of particulate emissions requirements over time. One utility described the experiences of a neighboring utility to provide an example of how changes in emission standards over time can contribute significantly to capital costs. As a result of a SIP change initiated by the state, the utility was forced to add higher efficiency precipitators at one of its large coal-fired powerplants, at a cost of well over $100 million, after only five years of operation with the powerplant's original precipitator. The case study utility also cited the experience of another company whose state environmental agency tried to increase the stringency of its particulate emission standards by an order of magnitude after a company demonstration test showed that the more stringent standard could be achieved--at least in the short run and so long as there were no further reductions in allowed sulfur emissions that would affect the precipitator's efficiency.

Water Pollutants

Water regulations place limits on thermal emissions, water intake damage to marine organisms, and the emission of pollutants contained in waste streams. Thermal emissions can be reduced with cooling towers or offstream cooling systems such as spray ponds. Water intake damage can be reduced through improved design of water intake facilities. Effluent wastes can be controlled with wastewater treatment facilities or by reducing the use of water pollutants.

The costs of complying with water regulations have generally not been large relative to air costs, reflecting the fact that controlling water pollutants typically requires less sophisticated control systems than those used to control SO_2. Some of the companies were able to avoid expensive retrofits for water intake and discharge systems by demonstrating minimal environmental impacts, as permitted under Sections 316a and 316b of the Clean Water Act (involving effects of water intake technology on marine organisms and involving thermal discharge, respectively). One of the companies noted that, because it had originally installed water pollution control equipment in powerplants that exceeded the existing state control requirements, it was able to avoid costly retrofits when more stringent federal regulations emerged. However, one case study company noted that another utility has had to install costly off-stream cooling systems and sophisticated wastewater treatment facilities at its coal-fired units to meet state and federal effluent regulations and to reduce water consumption.

In addition to direct capital, fuel, other operations, and maintenance costs, water permit requirements can lead to higher power production costs by restricting the use of water pollutants. For example, chlorine or other biocides are commonly used in noncirculating cooling systems to reduce organic growth on condenser tubes. Restrictions on the use of these biocides tend to necessitate more frequent reductions in a powerplant's output to allow physical cleaning of the condenser and to result in additional organic growth which reduces powerplant efficiency.

Extending the Operating Lives of Existing Powerplants

Utilities concerned about siting problems or financial constraints have considered and are considering extensions of the remaining operating lives of existing powerplants, even if such extensions could result in higher consumer costs. Environmental regulations have increased the economic attractiveness of such extensions by increasing the costs and risks associated with building new coal-fired powerplants and other capacity expansion alternatives. Moreover, by continuing to operate an existing powerplant, a utility can postpone siting and other environmental difficulties and can reduce its capital outlays for new powerplants. The case study companies did not provide any examples of actual decisions to extend the operating life of a powerplant. However, one PUC staff member believed that siting difficulties resulting from environmental regulations and economic considerations will make such extensions a necessity in his state--a state characterized by poor air quality.

Extending the operating life of an existing powerplant can necessitate additional environmental controls if equipment modifications result in a net increase in pollutant emissions of sufficient size to classify the changes as a major powerplant modification. In some circumstances, utilities may be able to avoid a net increase in emissions by using higher quality fuels. In other circumstances it may be necessary to install pollution control equipment at the powerplant or, alternatively, at other nearby generating units.

EPA is concerned that stringent new source requirements will cause utilities to delay the retirement of existing powerplants that do not meet the standards for new sources, thereby increasing total pollutant loadings. However, with respect to the case study companies, no consensus was apparent concerning the environmental impact of extending the useful life of an existing powerplant. The environmental effects, of course, depend on the difference in pollutant emission rates between the existing powerplant and the new powerplant whose construction is deferred. Despite the increasing stringency of requirements applicable to new powerplants, the retirement of old powerplants is not always environmentally advantageous. According to utility managers, extending the life of an existing oil-fired powerplant rather than constructing a new coal-fired powerplant can result in either a net increase or decrease in SO_2 emissions, depending on the situation.

Oil Displacement

A national energy policy goal is to displace oil consumption to reduce the nation's dependence on foreign oil. Utilities can displace oil by converting existing oil-fired units to coal, by displacing generation from oil-fired units with power from new coal-fired or nuclear units or from unconventional sources of energy, and by substituting coal-oil mixtures for oil. This section reviews the factors influencing utilities' decisions to reduce their consumption of oil, including the role that environmental regulations have played in those decisions.

The decisions to take actions that displace oil depend on a number of economic, financial, and technical considerations. Many prospective conversions are uneconomical because the units were not originally designed to burn coal and would require major or total boiler rebuilding to do so. Some reconversions of coal-capable units have been precluded by site-specific technical problems, such as lack of adequate space for fuel handling and storage. Financial constraints can also be a factor. Some utilities may decide not to undertake conversions or the construction of new coal-fired powerplants to displace oil because of the large capital investments involved. Environmental regulations may also discourage conversions and the construction of new coal-fired units for oil displacement by adding to the capital costs and risks of such projects and by increasing unit operating and maintenance costs.

Despite all the factors inhibiting oil displacement, flexibility in implementing environmental regulations has led to some conversions from oil to coal. One case study company described successful conversions undertaken by two other companies, not included in the case studies, where the companies and various regulatory bodies acted in concert to reduce both the cost and the uncertainty associated with environmental regulations. The first company was able to achieve major fuel cost reductions without incurring the environmental cost increases associated with a full PSD review because the Department of Energy issued a prohibition order that precluded the continued use of oil at this unit. As a result of the prohibition order, the company could meet the applicable sulfur dioxide regulations by using low-sulfur coal, rather than a scrubber. However, the company did add precipitators to the converted units.

The second company taking action on oil displacement converted an oil-fired powerplant based on projected cost savings that were protected through negotiation. Before the conversion, the company negotiated with EPA and its state environmental agency for assurances that environmental requirements for the powerplant would remain unchanged in the future. The state agency agreed to exert its best efforts to place the burden of any changes in pollution control requirements onto new powerplants and EPA informally indicated its support of this agreement. The company also negotiated with EPA for the elimination of a requirement to install scrubbers. EPA dropped its demand for scrubbers based on a company commitment to maintain SO_2 emissions equal to or below those previously emitted by the unit. The installation of a precipitator was required, but its costs are much less than expected fuel cost reductions.

Some of the case study companies are pursuing alternatives to displace oil other than converting boilers from oil to coal. A number of companies are investigating unconventional sources of energy such as wind, solar, and synthetic gas. One of the companies, located in an urban area, is studying the economics of constructing a synthetic gas manufacturing facility to supply one of its oil-fired units, rather than converting the unit to coal. The company believes that displacing the oil with synthetic gas may be the most economical alternative for three reasons. First, converting the powerplant to burn coal would be much more expensive than making the minor modifications necessary to burn gas. Second, there is inadequate space at the plant site for coal handling and storage and for a scrubbing system, making conversion very costly if not impossible. Third, the company expects the costs of controlling pollutants at the synthetic gas manufacturing stage to be substantially less than controlling pollutants at the coal-burning stage, thereby making synthetic gas more economical. In addition to economic considerations, the company noted that the urban location of the powerplants being studied would create substantial public opposition to converting the powerplant from oil to coal.

Some case study companies are also analyzing the use of coal-oil and coal-water mixtures in powerplants that were not originally designed for coal and that would be prohibitively expensive to convert. One company that hopes to convert some of its oil-fired units to coal-oil mixtures indicated that it anticipates having to install precipitators, but expects that it can avoid the need to install scrubbers by controlling the sulfur content of its coal-oil mixtures. Other companies are concerned that the use of coal-oil and coal-water mixtures may be precluded by technical problems related to boiler designs. In addition, they may be precluded by insufficient space at powerplant sites for the addition of scrubbers and precipitators or baghouses that would be required by state regulations.

ELECTRIC UTILITY CAPACITY PLANNING AND ENVIRONMENTAL REGULATIONS

Many factors, including environmental regulations, influence capacity decisions. The discussion is organized into four parts. The first part presents a general description of the capacity planning process in the case study companies. The second part discusses the companies' efforts to anticipate and manage the costs and risks associated with environmental regulations. The third part reviews the case study companies' evaluation of non-coal capacity alternatives. The fourth part discusses the coal-fired powerplant alternative.

Background on the Capacity Planning Process

Capacity planning is the process of determining a strategy for expanding and modifying company facilities to meet projected electricity demand. It includes the determination of the amount, type, location, and timing of additions to a company's generation (and related transmission) facilities, as well as modifications to or retirement of such facilities.

The case study companies to some degree coordinate their own generation capacity planning with that of other companies. The degree of coordination depends first on the scale of a company. If a company is itself large, it may by itself be able to exploit the economies of scale and diversify operational and financial risks. The degree of coordination depends also on geographical factors and on the availability of other companies for whom joint activities would be beneficial. The degree of interaction may also depend on a welter of other considerations, such as regulatory constraints or regional attitudes concerning public and private power companies.

The benefits of coordinated planning and operations, if any, tend to be exploited because there typically is a considerable exchange of information on demand forecasts and capacity requirements between companies. This takes place through regional electric reliability council activities, industry association meetings (such as those organized by the Edison Electric Institute or the Electrical Power Research Institute), or a variety of informal gatherings (such as those hosted by investment banking firms).

In addition, some companies have formed formal power pools or coordinating groups. In New England and in the Pennsylvania-New Jersey-Maryland region, for example, central pool staff dispatch the units owned and operated by the member companies. In New England, the pool also determines the capability requirements (capacity or firm contracts for capacity owned by others) of each member and levies penalties if a company falls short of meeting its demand with an adequate reserve margin. In the Ohio area, on the other hand, the coordinating group does not dispatch its members' units, but rather serves as a vehicle for companies to plan, construct, and operate jointly owned facilities.

Although some of the companies in the case study sample are members of relatively highly centralized power pools, the capacity planning processes of the companies studied are basically similar. A company starts the process by examining short- and long-term forecasts of demand. It then typically formulates several different capacity expansion plans that meet its forecast of average and peak electricity demands, giving due consideration to the reliability of generation and the uncertainty of demand. The company may consider joint ownership of large powerplants to realize the economies of scale associated with such powerplants and to match the size of capacity additions with its needs. Next, each potential expansion plan is screened with respect to a set of criteria that reflect the company's objectives and priorities. For the plans that pass the screening tests, detailed capital and operating costs are then calculated and evaluated in terms of their financial requirements and effects on consumer prices. Since the resultant electricity prices may change demand, a company may have to revise its load forecast and capacity expansion plans. Thus, the process is iterative, although many elements of the analysis are prepared concurrently using detailed computer simulation models. Reflecting the importance of investment decisions, senior management at each company is heavily involved in each step of the process.

Environmental Planning

The case study utilities have modified and augmented their capacity planning processes in an attempt to reduce the costs and uncertainties associated with environmental regulations. All the case study companies have environmental departments that help to develop feasible approaches to expanding capacity and provide ongoing advice on the effects of environmental requirements on the feasibility and costs of each approach. Their activities include providing information on specific environmental requirements, on the costs and risks associated with compliance strategies, and on possible regulatory changes. They also engage in detailed environmental planning, including participating in the search for acceptable project sites, identifying critical environmental problems that may force project cancellation, and planning various permitting and licensing activities. These planning activities are often initiated many years in advance of actual plant construction in order to secure necessary environmental approvals and to protect against unexpected delays.

Despite their careful planning, all of the case study companies believe that delays related to environmental approvals have increased their planning and construction time spans and, therefore, have increased their capacity expansion costs. However, none of the companies has performed the detailed analysis needed to establish the magnitude of the costs of environmentally related delays.

One company confronted with a particularly complex set of federal, state, and local requirements has developed a systematic program for strategic environmental forecasting and planning. Key elements of this program include summarizing the company's current environmental difficulties, examining trends in environmental regulations, and forecasting the company's environmental setting. This information provides a basis for designing action programs to address critical environmental problems and influence the course of regulatory developments.

Environmental planning has played an important role in shaping some companies' capacity plans. The type, siting, and size of powerplants have all been affected by environmental considerations. In at least one instance, the planned in-service dates of powerplants have also been affected; one company has forecast a relaxation in the environmental requirements it has to meet and, as a result, has delayed the planned in-service dates of its conventional capacity expansion alternatives.

Some companies have increased their spending on environmental research and development as part of their strategy for dealing with environmental regulations. They view these efforts as extremely important, not only for developing cost-effective ways to achieve compliance, but also for providing technical information that can be used to support efforts to change environmental regulations.

The case study companies plan for environmental contingencies in a number of ways. Companies generally prepare and apply for multiple sites for an individual project. One company designed a powerplant's pollution control facilities to exceed the prevailing environmental requirements to protect itself against future changes in environmental regulations and to reduce the risk of compliance problems. While this strategy resulted in initial costs higher than they needed to be, in the long run it resulted in considerable savings when regulations did become more stringent. However, this approach may result in costs that are higher than necessary if the stringency of environmental regulations for a specific powerplant remain unchanged or are increased even beyond the capabilities of the powerplant's pollution control equipment. One company has tried to hedge against regulatory changes by securing coal supply options for coals of various qualities. The case study companies also try to reduce the potential adverse consequences of regulatory delays by spreading their risks over more plants, for example, by making arrangements for purchased power and by participating in the joint ownership of powerplants. One company is seeking to increase its flexibility by developing unconventional sources of energy because some of them have shorter lead times and fewer environmental and siting problems than conventional capacity alternatives.

Non-Coal Power Supply Alternatives

This section reviews the major factors influencing the case study utilities' selection of ways to meet future demand other than by the construction of coal-fired plants. The alternatives discussed include conventional baseload units fueled by oil, gas, and nuclear fuel, unconventional sources of energy, and purchased power. In addition, the alternatives of changing power system reliability criteria and conservation and load management programs are discussed.

Because of the importance of coal as a capacity alternative and because of the substantial impact of environmental regulations on coal-fired powerplants, the alternative of building new coal-fired powerplants is discussed separately in a later section.

Oil- and Gas-Fired Powerplants

FUA eliminates new oil- and gas-fired baseload units as capacity expansion alternatives. Some of the case study companies also indicated that they would not construct such baseload units, even if this legislation were repealed, because increasing oil and gas prices and supply uncertainties have made new oil- and gas-fired units unattractive in comparison with new coal-fired baseload units. Although FUA also restricts the use of gas in existing baseload units, several companies expressed an interest in continuing to burn gas in existing gas-fired units or in converting oil-fired units to gas because such actions would reduce or at least not increase their reliance on foreign oil and would avoid the capital costs and environmental difficulties associated with coal.

Nuclear Powerplants

All of the case study companies have rejected the option of starting new nuclear powerplants before the 1990s, although the utilities plan to complete nuclear units presently under construction. New nuclear units have been rejected despite the fact that the companies believe that the cost of nuclear power is competitive with coal-fired powerplants, especially after factoring in the costs of dealing with the air and solid waste pollution problems associated with coal-fired powerplants. The companies have rejected nuclear power in large part because of uncertainties stemming from political and public opposition to nuclear power, which opposition can lead to the denial or delay of necessary permits and costly construction delays or cancellations. The utilities noted that the long lead times associated with new nuclear units, estimated to be 10 to 15 years, create unacceptably large financial risks. Furthermore, the absence of a federal policy for the disposal of nuclear wastes creates uncertainty as to the methods to be used for disposal of wastes, the location of waste disposal sites, and, ultimately, the cost of waste disposal. Utilities are also highly adverse to the risks associated with NRC regulations. These risks include possible shutdowns, additional capital costs for equipment changes, operating license suspensions, and increased operating costs stemming from regulatory changes.

Unconventional Capacity Alternatives

The prospect of a continuation of increasing energy costs and a desire to reduce dependence on foreign oil has motivated many utilities, especially those with oil-fired powerplants, to explore so-called "unconventional" technologies. These include those that use wind, direct sunlight, wood, and geothermal energy for generating power. They also include well-known power-producing technologies such as cogeneration and low-head hydro. However, despite the new interest in these technologies, unconventional capacity alternatives are expected to contribute only modestly to total capacity requirements. Moreover, even the companies interested in such technologies have contingency plans for conventional capacity alternatives in the event that problems preclude the development of unconventional alternatives at reasonable costs.

Some case study companies with a heavy dependence on oil generation are actively studying or pursuing selected unconventional alternatives, not only because they have potentially attractive economics, but also because they have fewer environmental problems. Unconventional alternatives typically involve smaller amounts of capacity, thereby increasing planning flexibility; they are politically popular; and they might reduce capital requirements per kilowatt relative to conventional plants. Unfortunately, some unconventional alternatives are expected to remain uneconomic in the near-term, and possibly for the long-term. In addition, some unconventional alternatives also have their environmental difficulties. One company noted that a neighboring company's geothermal project has been significantly delayed as a result of public and regulatory concern about the project's site in a pristine area.

Some companies are trying to improve the economics of unconventional capacity alternatives. One case study company is actively encouraging vendors to develop new technologies by providing a market for their products. It has also directly committed funds to increase its own research and development. Another company is trying to improve the economics of an unconventional project through DOE support.

Purchased Power

Purchased power can be an attractive way for a utility to meet future demand because it typically does not require a capital investment and because purchased power costs are usually passed through directly to consumers. Other reasons for purchasing power include increased flexibility in capacity planning, displacement of oil, and the avoidance of environmental difficulties for the purchaser.

Sellers of power to other utilities are motivated by the favorable economics of making better use of their capacity. Sellers of power often enter into sales contracts for specific time periods, after which they expect to use the powerplant to meet increased demand in their own service territory. These time periods may be for a number of years. In some instances, the contract may run for the life of a unit.

Three major factors have caused most of the case study companies to consider only moderate purchases of power. First, opportunities to purchase power tend to be limited in amount and may become more limited as the industry's reserve margins and excess transmission capacity decline. Second, purchased power may become less available as individuals or organizations in states that currently export power exert efforts to inhibit the movement of power out of their states to avoid increased levels of air and water pollution. Third, PUCs may disallow purchased power expenses if such power is more costly to a company's consumers than power from additions to the company's capacity.

The net impact of purchases of power on the environment depends on situational factors. In addition to changing the geographic location of the emission of pollutants, purchases of power may increase or decrease the total level of emissions of various pollutants. The net effect depends on the characteristics of the seller's powerplants and the generation alternatives available to the buyer.

Synthetic Fuel for Powerplants

The high cost of oil, the risks of a heavy dependence on foreign oil, and the environmental problems associated with coal have prompted two of the case study utilities to consider the use of synthetic fuels. One of the companies is participating in a demonstration project involving the use of methanol as a boiler fuel. It is also considering a multi-company project to produce synthetic gas from coal, but is concerned because synthetic gas transported over state lines might be subject to the Federal Energy Regulatory Commissions's priority rules for gas use, and therefore might be an undependable source. Another case study company believes that a combined-cycle powerplant fueled with synthetic gas may be its most economical long-term capacity expansion alternative, given the relatively stringent environmental standards and the high costs of low-sulfur coal in the company's service area. Nonetheless, this company is concerned about the technological and environmental risks associated with a commercial-size synfuels plant, which would be an order of magnitude greater than current demonstration plants. One alternative being considered to help alleviate these problems is to build many small manufacturing units in place of one large unit.

The other four case study utilities, while monitoring synfuels developments, have expressed little current interest in synfuels for several reasons. First, synthetic fuels are presently not cost-competitive relative to conventional oil and natural gas and may remain uncompetitive in the future. Manufacturing and using synfuels in either existing or new powerplants are viewed as even more likely to remain economically unattractive when compared with building new coal-fired powerplants. Second, some of the companies interviewed were concerned that their state regulatory commissions would not adequately reflect in their rate decisions the increased technological and environmental risks associated with developing and using synfuels. Third, the companies consider the possibility of changes in environmental regulations for synfuels manufacturing, which have not yet been promulgated, to be a significant source of uncertainty.

Power System Reliability

Generally, the case study companies view reducing reliability standards in order to postpone capacity additions as an alternative of last resort because of the strong adverse public reaction that would be likely to result from significant reductions in the quality of service. Given the sensitivity of consumers to service reliability, both utilities and their PUCs tend carefully to monitor the frequency and duration of service outages.

Even though a high level of reliability continues to be a primary objective of each of the companies, their histories and expectations of inadequate returns have led some of the case study companies to lower or to consider lowering their historical reliability standards to postpone capacity additions. To reduce its capital spending, one company, despite a relatively strong current financial position, is carefully evaluating whether it can lower its current reliability criteria without incurring strong adverse customer reaction. Another company's poor financial condition has already led it to reduce its reliability criteria for its transmission and distribution network. However, the company has not changed its reliability criteria for generation capacity planning because generation shortfalls affect much larger numbers of customers and are less easily remedied than transmission and distribution problems. Another company stated that it might be unable to finance any capacity additions necessitated by increases in demand beyond the modest growth it currently forecasts. The company indicated that, if demand growth increased and its regulators did not take steps to improve its financial condition, it would be forced to let reliability decline.

Conservation and Load Management

The increasing cost of producing electricity and building new capacity has stimulated substantial interest in conservation and load management programs. A number of the case study companies are implementing ambitious conservation programs to reduce their capital expenditure requirements, environmental problems, oil consumption, and consumer costs. These programs include customer education programs, customer energy audits, promotion of solar water and space heating, assistance in designing energy-efficient buildings, and expanded use of interruptible rate structures. One company also has a program to install insulation at customer sites. However, some of the case study companies have undertaken only minor conservation efforts because they have not been able to identify cost-beneficial opportunities for major programs. In addition, one of these companies, which currently has a large reserve margin, is not interested in pursuing a major conservation program because reductions in demand could lead to short-term declines in profitability.

Two of the case study companies are planning, or have partly implemented, load management programs. These programs are designed primarily to reduce peak demand (i.e., flatten the pattern of demand), although they may also reduce energy demand. Reduced peaking allows a company to meet a larger portion of its demand with baseload units, which are more efficient than peaking units, and reduce its total capacity requirements. The two companies' load management programs primarily focus on the use of alternative rate schedules, such as time-of-use rates, and on experimental testing and development of load management devices, such as energy storage systems, the use of solar energy at the customer site, and the remote cycling of air conditioners, electric water heaters, and other devices.

Other case study companies are also experimenting with load management systems, but these companies have not been able to justify significant programs on a cost-benefit basis due to the shape of their demand pattern. For example, one of these companies has a relatively even pattern of demand because its large and highly interconnected service territory results in a diversification of weather-related demand and because it has a relatively important industrial load.

Coal-Fired Powerplants

For two reasons, most of the case study companies view coal-fired units as the primary alternative for baseload capacity expansion--despite the significant environmental problems associated with coal. First, the companies have rejected the alternative of new nuclear units and FUA and economic considerations have eliminated new oil- and gas-fired powerplants as alternatives. Second, opportunities to meet increases in baseload demand with the remaining alternatives are limited; many of them, moreover, are in an early stage of technological development and are presently uneconomical.

Coal-fired powerplants, even if economically attractive, require large capital investments and present significant environmental problems. The environmental problems include problems in achieving compliance, the possibility of retrofit requirements, siting difficulties, the technological risks associated with pollution control equipment, and problems in securing high-quality coal. The requirements for pollution control equipment also add substantially to the capital cost of new coal-fired powerplants.

The range of choices made by the case study companies regarding new coal-fired powerplants reflects their differing economic, financial, and environmental circumstances. A number of the companies plan to meet increases in baseload demand primarily with new coal-fired units because they result in the lowest total customer costs. Although these companies are concerned about the capital cost of new units, financial concerns and environmental regulations have not proven to be critical constraints. Other companies are aggressively pursuing unconventional sources of energy and have relegated new coal-fired units to a contingency alternative for the long term, despite the fact that new coal-fired units could potentially be used as an economical means of displacing oil. These latter companies have relegated new coal-fired powerplants to a contingency role primarily because of the capital expense of such units and secondarily because of difficulties stemming from stringent environmental regulations. Lastly, as previously discussed, one company believes that a combined cycle plant fueled by synthetic gas may prove to be a more economical alternative than new coal-fired powerplants largely because of the pollution control costs associated with coal in its service area.

The remainder of this section provides a more detailed discussion of the environmental issues associated with coal. The discussion covers pollution control requirements for new coal-fired powerplants, utility concerns about technology-forcing regulations, and siting difficulties. Utility concerns regarding fuel prices and fuel quality are discussed at length in Appendix D.

Environmental Requirements

New coal-fired units are subject to federal and state environmental regulations. As discussed in Chapter II, federal regulations include new source performance standards (NSPS), PSD, and nonattainment regulations. PSD regulations apply to regions where the air is cleaner than the National Ambient Air Quality Standards (NAAQS) for at least one criteria pollutant. Powerplants sited in PSD regions are required to employ best available control technology (BACT) for controlling of emissions and to remain within the PSD air increments. Nonattainment regulations apply to areas that violate NAAQS for at least one criteria pollutant. These regulations require the utilities to use lowest achievable emission rate (LAER) pollution control technology and to secure enough emission offsets so that there is a net reduction in total pollutant loadings. BACT and LAER are determined on a case-by-case basis and must be at least as stringent as NSPS. Since NSPS, BACT, and LAER requirements often force a utility to employ an advanced level of pollution control equipment, they are frequently referred to as technology-forcing regulations.

For a number of the case study companies, state regulations are somewhat more restrictive than federal requirements. The stringency of a SIP is generally a function of the state's ambient air quality and the environmental desires of the public and the state's political leaders. The stringency of a SIP for electric utilities also depends in part on the extent to which a state has placed the burden of pollution control on electric utilities, as opposed to other industries and activities (e.g., transportation by automobile). In designing SIPs, states essentially take an inventory of sources of pollution and then allocate the burden of controlling pollution, taking into consideration the technical and financial ability of different industries to reduce pollutant loadings and the effect of different control strategies on employment and other socioeconomic variables.

One state's promulgation of standards more stringent than federal requirements reflects a number of specific concerns. First, the regulations were designed to compensate for what was viewed as reluctance on the part of EPA to require advanced levels of control technology under NSPS. Second, the regulations were designed to be stringent to provide an incentive for utilities to develop pollution control technologies. Third, this state's regulators were concerned that the uniform national standards, promulgated in the early 1970s, provided an impetus for industry to move from other states to exploit the state's air resources. Finally, the water regulations affecting the state's utility plants were designed to conserve scarce water resources to allow industrial growth.

Three case study companies currently building new coal-fired powerplants have sited these plants in PSD regions. These companies do not view environmental requirements as critical obstacles, although they result in significant capital and operating costs. Two companies expect that BACT for the control of sulfur dioxide and particulate emissions will require relatively advanced scrubbers and precipitators and coals of at least moderate quality. The third company, which is subject to state environmental requirements which are somewhat more stringent than federal requirements, expects to achieve compliance through the installation of state-of-the-art pollution control equipment including a dry scrubber, baghouse, cooling tower, and a zero discharge wastewater treatment system. In addition, the company plans to meet NO_x requirements by contructing and installing boilers and burner tips designed to control NO_x emissions.

Of the three case study companies with powerplants under construction, two were able to avoid or reduce the impact of BACT standards. One company successfully litigated for the exemption of a powerplant under construction from PSD regulations that would have required the installation of a scrubbing system. Scrubbers would have increased the capital cost of the powerplant by approximately 20 percent and the company believed it could meet air quality standards at a lower cost by using low-sulfur coal. The other company reduced the impact of BACT standards at one powerplant by obtaining its PSD permit before PSD regulations took full effect. The third company, which has more willingly sought to comply with environmental regulations, has successfully negotiated with environmental agencies for the relaxation of environmental standards on the basis of difficulties in designing and operating its pollution control equipment.

Technological Concerns

EPA's adoption of technology-forcing regulations for new powerplants reflects the idea that the most cost-effective way to achieve a clean environment is to require stringent pollution controls for new sources. Although EPA is concerned that stringent requirements for new sources may encourage utilities to delay the retirement of relatively dirty, existing powerplants, stringent new source requirements are intended to ensure an increasingly clean environment as existing powerplants are replaced by new plants. EPA's requirement of advanced technology for new powerplants also recognizes that installing pollution control equipment during the construction of new plants is much less costly than the retrofitting of existing plants and that this equipment can be used for a relatively long period of time.

The case study utilities are generally concerned about the costs and risks of pollution control technology for new coal-fired powerplants. A number of the companies argue that the technology-forcing nature of BACT and LAER creates significant technological risks and uncertainties and unnecessarily increases costs. For example, LAER standards can be changed by EPA or state environmental agencies even for plants already under construction. Thus, as new pollution control technologies are developed, utilities can be forced to adopt equipment close to or at the state-of-the-art, creating uncertainty as to the cost and reliability of the equipment. In response to this line of reasoning, one state environmental agency argues that the long lead time for new coal-fired powerplants will provide enough time to further develop pollution control technologies, thereby increasing their reliability. This agency attempted to ensure that one utility meet its standards by requiring the utility to leave sufficient space in a new unit during its construction to allow the installation of any of a number of technologies. The agency believed that the technologies would be sufficiently developed by the end of the construction period to meet its standards with a high degree of reliability.

Largely because of the costs and risks associated with pollution control technologies, one case study company relegated the alternative of a new coal-fired powerplant to a contingency status. This company is subject to relatively severe technological requirements imposed by state and federal regulations. EPA requires pollution control technology that will meet its LAER standards for new powerplants in nonattainment areas and the company's state regulations require a level of technology for all new powerplants that is usually equivalent to LAER technology even in attainment areas. LAER requirements for new coal-fired powerplants in the company's service territory include the use of state-of-the-art scrubbers, precipitators, and combustion equipment to control nitrogen oxide. According to the utility, the cost of these systems, plus closed cycle cooling, could account for 50 percent of the total capital cost of a new coal-fired powerplant. The company is also concerned that the combination of pollution control systems could significantly degrade a powerplant's reliability. In fact, one state siting commission pointed out that no powerplant in the world presently operates with all three air pollution control systems at an advanced level of technology.

The company that has more willingly sought to comply with environmental regulations is also concerned about the potential for significant operating problems with state-of-the-art pollution control equipment, but hopes to avoid significant decreases in unit reliabilities. The utility's state environmental regulators may assist the utility in its efforts to maintain unit reliabilities by continuing to allow it to operate a powerplant while repairing the plant's scrubbing system. Even assuming that reliability problems do not necessitate further investment in backup pollution control equipment or generating capacity (or both), this company estimates that the total capital cost of pollution control equipment will approximate 30 percent of the total costs of a new coal-fired plant.

As is discussed further in Chapter VI, EPA also places the total cost of pollution control equipment at about 30 percent of total powerplant costs. EPA believes that scrubber reliability problems will not be significant once a utility gains experience with a new scrubber. However, EPA's projection of minimal reliability problems is based on expectations of highly reliable scrubbing systems, while the company's hope for minimal reliability problems is based in part on its regulators' allowing emission variances.

Siting Difficulties

The process used by the case study utilities in selecting potential sites for new powerplants is generally the same, although the details of each company's specific procedures and selection criteria vary somewhat. The first step in the process typically involves a scanning of the company's region to identify a relatively large number of potential sites with sufficient space, water, and transportation to support a plant. One case study company initially identified 40 potential sites; another company identified 12 sites. In the second step, the potential sites are culled on the basis of rough estimates of each site's economics and its possible environment problems.

In evaluating the relative economics of sites, factors such as distance from load centers, the need for new transmission facilities, adequacy of transportation links for fuel, and availability of water are considered. Sites in nonattainment areas or with inadequate PSD increments are screened out. In effect, the second step of the process attempts to identify knockout factors. The third step in the process typically involves detailed economic and environmental analyses of from three to six sites. From these candidates, companies often select not only the site that appears to have the lowest expected costs and risks, but also one or two backup sites.

The case study utilities generally agree that siting a coal-fired powerplant in an area subject to nonattainment regulations is nearly impossible due to difficulties in securing sufficient offsets. Although PSD regions are far more prevalent than nonattainment areas, a significant number of counties in some states are nonattainment areas. Moreover, offsets in rural nonattainment areas are often difficult to secure because their poor air quality is caused by wind transport of pollutants. Offsets in urban areas are considered generally to be too expensive, too diffuse, or simply unavailable in amounts sufficient to support a new coal-fired baseload unit. One company noted that industries with a potential for offsets are likely to save offsets for their own use.

The difficulty in locating new powerplants in nonattainment areas and the greater number of PSD areas have led utilities to focus their siting efforts on PSD areas. Although PSD regulations have not yet prevented any of the case study companies from constructing new coal-fired powerplants, these regulations present significant obstacles and, in the view of some companies, may in the future preclude the construction of such plants in some regions. Required modeling of powerplant emissions is becoming very complex because of increased overlapping of emissions from different powerplants in some industrialized areas and the proximity of many sites to mountains in nonindustrialized areas. Contests between utilities and environmental agencies over the acceptability of models can cause significant delays and possibly result in project cancellation. More importantly, inadequate PSD increments may eliminate preferred sites or limit the size of a new powerplant at a specific site, with a resultant loss of economies of scale.

The case study companies are divided on the issue of whether PSD increments will become a significant constraint in the future. About half of the companies stated that PSD increments may become a significant constraint as electric utility and other industrial growth exhausts many of the existing PSD increments. Potential siting constraints stemming from insufficient air increments appear to be caused mainly by relatively poor ambient air quality. Some companies believe that they will be forced to deal with severe environmental constraints as early as the mid-1980s as they plan for powerplants that will commence operation in the 1990s. For example, one case study company stated that there are no PSD increments left in its service territory large enough to support a large coal-fired powerplant. In addition, an industry observer has pointed out that, because of the state's poor ambient air quality, California may only have an "environmental carrying capacity" of a few thousand megawatts--equivalent to about one large coal-fired powerplant. One case study company predicted that the utility industry's resistance to environmental regulations will be much greater in the future as a greater number of utilities encounter the siting and compliance difficulties associated with new powerplants. The company believes that the present level of resistance has been reduced by recent declines in demand growth that have resulted in the cancellation or postponement of many utilities' construction programs.

The other case study companies do not view PSD increments as a serious constraint to the siting of large, new coal-fired units. This view is shared by some EPA officials who believe that no acceptable evidence that PSD increments have prevented or will prevent the siting of a powerplant has been presented. The case study companies holding this view generally have relatively good ambient air quality in and around their service territories. One utility, in a state with relatively pristine air quality and numerous Class I PSD areas, does not view PSD increments as a serious siting constraint because the large size of the state and the stringent control of emissions from new powerplants contribute to a large number of potentially acceptable sites. For this utility, water and coal sources are more critical constraints to siting new coal powerplants.

Another case study utility that does not view PSD increments as a serious constraint holds this view because of the relatively good ambient air quality of its service territory. This utility's state environmental agency observed that the use of high-sulfur fuel oil since the 1974 oil embargo resulted in emissions per megawatt greater than or equal to what is expected from new coal-fired powerplants with precipitators and scrubbers. Therefore, the eventual replacement of existing oil-fired powerplants with new coal-fired powerplants could increase the air increments available to the operation of new powerplants to meet increases in demand. This utility also noted that another utility was able to use an offset approach to enlarge a PSD increment so that it could site a new coal-fired unit at an existing powerplant location. The proximity of the location to a Class I PSD area and emissions from the existing powerplant resulted in exhausting a PSD increment, which precluded additional coal-fired units unless offsets could be used. With the consent of EPA, the utility enlarged the air increments to permit siting by taking steps to reduce the sulfur dioxide and particulate emissions of the existing powerplant. Particulate standards for the existing units were determined in conjunction with those of the new units and plans were established for reducing the sulfur content of the coal supply for the existing units as the new units were placed in service.

The regulatory process for siting a new powerplant is complex, typically involving a number of state and federal agencies, and can introduce uncertainty as to whether and when approval will be given for the necessary permits. Recognizing these problems, many states and EPA have taken steps to streamline the siting process. However, some states do not have central siting authorities and some state regulators are not convinced that they are effective. One executive in a state without a central siting agency argues that they create additional siting complexity and delays and dilute the authority of other state regulatory agencies. In this state, agencies can reject sites, but do not formally approve sites. Therefore, utilities are responsible for selecting acceptable sites. Nonetheless, a number of states have implemented "one-stop" permitting procedures whereby their siting agency coordinates all of the permitting and licensing activities necessary for a new powerplant or major modification of an existing powerplant.

The effectiveness of one-stop permitting procedures varies by state. One company has found its state's procedures to be very effective. It credits this effectiveness to its siting agency's efficient implementation of a one-stop procedure, a statutory permitting time limit, and the assignment of one hearing officer who is responsible for a siting request until it has been acted upon. Using this approach the company was able to site a large coal-fired powerplant in less time than the statutory permitting time limit. Another state that established a one-stop permitting process tried to give its siting agency the authority to make tradeoffs between environmental concerns and other siting criteria in order to increase both the speed and effectiveness of response. The siting agency has, however, encountered significant unwillingness on the part of environmental agencies to agree to the tradeoffs it considers necessary for the siting of coal-fired powerplants in a state characterized by relatively poor air quality. The state environmental agency takes the position that it cannot allow tradeoffs that violate its state implementation plan.

EPA is concerned about the efficiency and effectiveness of state permitting procedures and is encouraging and trying to assist states in their efforts to improve their procedures. Increased state permitting effectiveness is seen as improving the ability of states to assume additional environmental responsibility and as leading to improved coordination between EPA and state regulatory agencies. Improved procedures can also reduce permitting time delays, complexity, and uncertainty. EPA surveyed and summarized state efforts to revise procedures and distributed the results to the states in the January 1982 report "Streamlining the Environmental Permitting Process: A Survey of State Reforms" (by TBS for EPA's Office Management, June 1982). Furthermore, EPA is developing consolidated regulations for streamlining applications for facilities that require a permit under national pollution discharge emission system (NPDES), PSD, Resource Conservation and Recovery Act (RCRA), and underground injection control (UIC) programs. Although primarily for EPA's use in cases where EPA is the permitting agency, the consolidated regulations are intended to serve as a model for state procedures.

UTILITY RECOMMENDATIONS FOR IMPROVING ENVIRONMENTAL REGULATIONS

The case study utilities have offered a variety of recommendations for improving environmental regulations. These recommendations relate to formulating, administering, and changing existing environmental regulations. A recommendation common to all three areas is that greater emphasis should be placed on the use of cost-benefit and cost-effectiveness approaches and analyses.

Formulating Environmental Regulations

All of the case study companies recommend that EPA and state and local environmental agencies employ cost-benefit and cost-effectiveness analyses more extensively in their design and administration of environmental regulations. Cost-benefit analyses weigh the economic, health, and welfare benefits of pollution control and the economic, energy, and social costs of pollution control. Unfortunately, as the companies recognize, it is sometimes extremely difficult to quantify benefits, as well as some costs. Quantifying the benefits of a cleaner environment is difficult not only because of data unavailability, but also because of conceptual difficulties in defining the benefits associated with, for example, unspoiled vistas. In fact, some decision makers argue that cost-benefit analysis is in too primitive a state of development to qualify for a central role in decision making. Cost-effectiveness analyses avoid the problem of measuring the benefits of pollution control by focusing more narrowly on the costs and efficiencies of alternative pollution control strategies. For this reason, many utility executives would place more reliance on cost-effectiveness measures than on cost-benefit measures.

Some executives in one of the case study companies believe that public pressure for regulatory change will result in greater use of cost-benefit approaches in the setting and administering of environmental regulations and in less regulatory resistance to conventional baseload capacity expansion alternatives. They believe that increases in electricity prices, in part due to environmental costs, and decreases in reliability, due to siting and financing difficulties, will focus public attention on regulatory costs and will result in public pressure for less costly regulation.

Another unanimous recommendation for the formulation of environmental regulations is that regulators not change the environmental compliance requirements for a powerplant after it is constructed. This recommendation emerges because retrofits are generally more expensive than the installation of pollution control equipment during powerplant construction. It also reflects utility concerns about changes in environmental requirements that could result in plant shutdowns or expensive changes in operations.

Lastly, a number of companies have recommended that EPA strengthen the factual and scientific research used as the basis for designing new regulations. Many companies believe that an inadequate understanding of the effects of pollutant emissions has led EPA to adopt environmental standards with an overly wide margin of safety for the protection of human health and welfare. In their view, more complete research on the effects of powerplant emissions would allow EPA to more properly balance costs and benefits in its formulation of regulations and standards, thereby avoiding costly margins of safety not justified by their benefits.

Administering Environmental Regulations

The case study companies recommend a greater emphasis on cost-benefit and cost-effectiveness approaches and analyses also in the administration of regulations. The companies generally believe that an overly strict administration of environmental regulations by EPA and state environmental agencies results in unnecessarily high costs, although they also noted some instances where regulators have been flexible. As an example of overly rigid administration, one company noted that it was required to install a water cooling system at an ocean site despite the fact that, in its view, thermal emissions resulted in minimal, if any, harm to the environment. On the other hand, the companies provided two examples of cases where other companies had successfully negotiated for compliance strategies at what they believe to be a higher level of cost-effectiveness. In one example, a company reached a compromise with EPA that permitted it to install a "helper" cooling system, to be used at certain times of the year, in place of more expensive cooling towers. In the other example, a company was able to achieve what it saw as a reasonable level of cost-effectiveness in its treatments of wastewater by negotiating for the elimination of a proposed third stage of a wastewater treatment facility. The third stage, a polishing pond, would have slightly increased the effectiveness of the facility, but at a cost of over 15 percent of total facility costs. The company's state environmental agency supported elimination of the third stage on the basis of cost-effectiveness and EPA agreed to the elimination, but on the basis of site limitations. Unfortunately, despite eliminating the complexity of a third stage, the utility has had significant operating problems with the facility because even the two-stage process was a state-of-the-art design; the utility may be forced to replace it.

Some EPA officials believe that a greater emphasis on cost-benefit and cost-effectiveness analyses in administering environmental regulations may conflict with some industry recommendations to reduce uncertainty in the determining of environmental standards. These officials argue that, in a broad sense, EPA can either establish and enforce rigid emission or technology standards, thereby reducing utility uncertainty as to the specific standards they will be required to meet, or it can be flexible in its determination of standards in specific cases, thereby introducing greater uncertainty into utility environmental planning.

A number of companies support the use of emission tradeoffs since it creates opportunities for less costly compliance strategies. One company is lobbying for greater state regulatory support of emission tradeoffs since it believes that future compliance problems may present opportunities to use tradeoffs effectively.

EPA officials are concerned that situations may arise where emission reductions that would have occurred in the absence of tradeoff policies will be used to offset requirements for controlling of emissions. However, EPA allows a variety of offsets and is working to encourage their use. First, under PSD regulations, utilities can effectively avoid BACT requirements by "netting" pollution emission increases and decreases within a powerplant. In addition, utilities can "bubble" offsets external to a powerplant to preclude retrofit requirements, although the use of such offsets is limited by ambient air quality standards and PSD and nonattainment regulations. Third, EPA allows companies to "bank" (inventory) offsets and awards credit for emission reductions beyond those required. To encourage offsetting, EPA is promoting offset markets and is conducting workshops for offset traders. EPA also encourages states to formulate SIPs that facilitate offsetting.

Many of the case study companies also commented on or recommended changes in the administrative procedures and staffing of environmental agencies. They suggested that EPA increase its delegation of authority to the regional EPA offices and staff these offices with more knowledgeable and experienced people. These recommendations stem from the complaint that the inability of regional EPA employees to supply information or make major decisions has resulted in significant project delays. Many of the utilities have also observed that members of EPA's staff tended to be inexperienced and, as a result, tended to be unrealistic in their desires and expectations. They noted that a high degree of turnover has contributed to the inexperience of the staff.

One case study company recommended that the operating procedures for EPA and state environmental agencies be changed to increase the level of state decision making and decrease EPA's "second guessing" of a state agency's decisions. To facilitate site permitting, this company also recommends that utilities be allowed to inventory sites and that state siting agencies be given greater authority to make tradeoffs between environmental and other siting factors in their approval of sites.

Changing Environmental Regulations

Reflecting a variety of concerns about environmental regulations, and their desire that regulators place greater emphasis on cost-benefit and cost-effectiveness approaches, the case study companies recommend a number of changes in existing environmental regulations. Many of them recommend longer averaging times in the national ambient air quality standards and a greater allowance for emissions in excess of these standards. Increased averaging times would reduce the costs associated with controlling the variances in fuel quality and allow relaxation of pollution control equipment design and fuel quality standards. One case study utility recommends that regulators not classify emissions in excess of air quality standards as violations if these events occur infrequently. Another case study utility pointed out that a greater allowance for emissions greater than standards is almost mandatory since a certain level of emissions peaking cannot be avoided without incurring extreme capital and operating costs. Some utilities also believe that existing scientific evidence on the health effects of pollutant emissions does not justify a regulatory system effectively based on peak emissions. EPA is concerned, however, that longer averaging times may result in increased pollutant loadings. Some companies may have lowered their average rate of pollutant emissions to reduce or compensate for emission rate peaks that otherwise would have violated standards based on short averaging times. An increase in averaging times may allow these companies to increase substantially their average emission rates by allowing more frequent or more numerous emission rate peaks.

Many of the case study utilities recommend that PSD regulations immediately be rescinded or altered to reduce limitations imposed by air increments, monitoring and modeling difficulties, lengthy preconstruction review times, and the sheer complexity of the regulations. Specific suggestions for improvement include enlarging PSD air increments and developing state plans for allocating PSD increments, rather than having them available on a first-come-first-serve basis. Many utility executives also believe that PSD regulations are redundant or illogical based on the argument that established primary and secondary ambient air quality standards should be sufficient to protect human health and welfare. However, according to EPA staff, this view reflects a narrow interpretation of the objectives of the PSD program. While the PSD program is intended in part to protect human health and welfare, it is also designed to protect air quality in areas of special national or regional interest and to preserve existing clean air resources while allowing economic growth.

The utilities were almost unanimous in their belief that PSD regulations will be revised, at least as they apply to some regions, as a result of the difficulties and expense associated with complying with such regulations. One industry observer believes that exhaustion of PSD increments in some areas in the late 1980s or early 1990s will force either the enlargement of PSD increments or the repeal of the increment system.

Although none of the case study utilities had specific recommendations regarding visibility regulations, they noted that a number of western utilities recommend that existing visibility regulations be rescinded or made less stringent and that new visibility regulations not be considered until further research has been completed. The western utilities are particularly concerned about the possibility that either existing or proposed visibility regulations will require costly reductions in NO_x emissions.

Some electric utility industry executives also advocate the abandonment or modification of technology-forcing regulations to counteract what they perceive to be two major problems. First, technological decisions and constraints imposed by EPA may be based more on developments in control technologies than on cost-benefit and cost-effectiveness considerations. Second, technology-forcing regulations may discourage technological innovation and improvements. Utilities and vendors of pollution control equipment may be reluctant to invest in research and development for specific technologies due to the risk that competing technologies will be chosen as LAER or BACT technologies, thereby eliminating their market. This risk is exacerbated by the fact that LAER does not have to be chosen on the basis of cost-effectiveness. One utility recommends that EPA not change BACT and LAER standards for specified time periods to reduce the risk of technological developments becoming obsolete as a result of regulatory changes.

Some EPA officials and a number of utilities disagree about the use of technology-forcing regulations. The EPA officials believe that utilities have little incentive to develop more advanced control technologies in the absence of regulations that force such developments. In contrast, while accepting that there is some need for a continual tightening of standards, some utilities argue that a much more positive and effective regulatory approach to encouraging technological innovation and the installation of state-of-the-art pollution control equipment is to provide economic incentives for such activities.

The changes to existing regulations recommended by the case study utilities address many, but not all, of the major concerns espoused by electric utility industry organizations. For example, the Edison Electric Institute has advocated two changes to the Clean Air Act that did not surface in TBS's interviews. First, BACT, LAER, and NSPS requirements should be replaced with one set of NSPS requirements to eliminate uncertainty and reduce the time and efforts associated with environmental regulation. Second, to encourage oil displacement, voluntary coal conversions should be exempted from new

IV. GENERATING UNIT EFFECTS

CHAPTER IV

EFFECTS OF ENVIRONMENTAL REGULATIONS ON ELECTRIC UTILITY UNITS

CONTENTS

CONTENTS
(continued)

IV. EFFECTS OF ENVIRONMENTAL REGULATIONS ON ELECTRIC UTILITY UNITS

INTRODUCTION AND MAJOR FINDINGS

This chapter examines strategies for and costs of compliance with environmental regulations for individual electric generating units. The objectives of the chapter are, first, to determine average costs for pollution control incurred by fossil steam units and, second, to compare compliance strategies and costs among units. Such an analysis permits an identification of unit-level costs that would otherwise not be apparent in an aggregate analysis that includes a large number of minimally affected units.

The analysis in this chapter is based on data compiled in the Energy Database concerning the characteristics, environmental compliance strategies, and costs as of December 1979 of steam-electric generating units burning fossil fuels for which a Form 67 was submitted to the Department of Energy (DOE) in 1979.[1] These 2,277 units have a capacity of 395,868 MW, which represents approximately 96 percent of total capacity of fossil-fired steam-electric units reported in DOE's 1979 Inventory of Powerplants.[2] Units not included in the analysis are primarily those in plants with capacities of less than 25 MW that do not submit Form 67s.

Distribution of Units by Fuel Type and Age

Coal-fired units account for nearly 60 percent of the capacity of units in the Energy Database (Table IV-1). The remaining 40 percent of capacity is relatively evenly distributed among units that burn oil, gas, and oil and gas combined.

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[1] Form 67s, "Steam-Electric Plant Air and Water Quality Control Data," summarize unit-level pollution control data and are submitted annually to DOE. For a description of the Energy Database see Appendix A.

[2] U.S. Department of Energy, Inventory of Powerplants in the United States, December 1979.

Table IV-1

DISTRIBUTION OF FOSSIL-FUEL UNITS BY FUEL TYPE[1]

Fuel Type	Percent of Units	Percent of Capacity
Coal	47	59
Oil	17	15
Gas	17	13
Gas/Oil	19	13

[1]Totals may not add to 100 percent due to rounding.

Source: Energy Database.

Eighty-six percent of the units in the Energy Database were in service by 1972 and thus predate the 1971 Clean Air Act and the 1972 Clean Water Acts (Table IV-2). Environmental compliance for these units has consisted of retrofitting pollution control equipment to comply with regulations for existing sources promulgated under the Clean Air and Clean Water Acts. Units that came into service in 1972-1976 have also been subject to existing source air and water regulations, but in most cases these units have not been required to retrofit pollution control equipment as they generally were designed taking air and water regulations into account. Finally, units

Table IV-2

DISTRIBUTION OF FOSSIL-FUEL UNITS BY IN-SERVICE YEAR[1]

In-Service Year	Percent of Units	Percent of Capacity
Pre-1972	86	63
1972-1976	9	25
1976-1979	5	12

[1]Totals may not add to 100 percent due to rounding.

Source: Energy Database.

that have come into service since 1976 have as a rule been subject to new source standards under the Clean Air and Clean Water Acts.

Environmental Compliance Strategies

Strategies for compliance with sulfur dioxide (SO_2) and total suspended particulates (TSP) requirements among coal units reflect increasingly stringent standards. Only 23 percent of coal capacity that came into service before 1977 either burns coal with less than 0.8 percent sulfur and/or has flue gas desulfurization (FGD) systems (Table IV-3). The proportion of capacity in this category rises dramatically to 73 percent of 1977-1979 capacity and to 98 percent of capacity that is projected to come into service in 1980-1984. This increase reflects primarily the increasing use of scrubbers from 5 percent of pre-1977 capacity, to 35 percent of 1977-1979 capacity, and to 52 percent of 1980-1984 capacity.

Table IV-3

DISTRIBUTION OF COAL CAPACITY
BY REPORTED SO_2 COMPLIANCE STRATEGY

(percent of age-category capacity)

SO_2 Compliance Strategy	In-Service Year		
<0.8% Sulfur Coal	Pre-1977	1977-1979	1980-1984
With FGD	2	22	14
Without FGD	18	38	46
>0.8% Sulfur			
With FGD	3	13	38
Without FGD	77	27	2
Total	100	100	100

Source: Energy Database.

Coal units of different vintages also reflect different TSP requirements. Over 96 percent of the capacity in units in all age categories has TSP collection systems whose removal efficiencies are above 98 percent. Units that came into service before 1972, however, have frequently retrofitted electrostatic precipitators alongside older, less efficient mechanical collectors.

Air pollution control strategies at oil and gas/oil units consist primarily of the use of low-sulfur oil to control SO_2 emissions. Over 60 percent of the capacity in oil-fired units burns oil with less than 1 percent sulfur by weight. A further 30 percent of this capacity burns oil with 1 to 2 percent sulfur, and less than 10 percent uses oil with more than 2 percent sulfur (Table IV-4). Particulate emissions are reduced both by burning low-sulfur oil (because it is a higher-quality fuel with fewer impurities) and by installing TSP control equipment. However, only 40 percent of oil and oil/gas capacity has particulate control systems and less than a fourth of these systems have removal efficiencies greater than 98 percent.

Table IV-4

DISTRIBUTION OF OIL CAPACITY BY REPORTED SO_2 AND TSP CONTROL STRATEGY[1]

SO_2 Control		TSP Control Equipment	
Fuel Percent Sulfur	Percent of Capacity	TPS Collection Efficiency (%)[2]	Percent of Capacity
<0.9	63	>98	8
1-1.9	29	90-98	17
>2.0	8	<90	14
		No equipment	60

[1]Includes gas/oil units.
[2]One percent reported TSP equipment but did not specify control efficiency.

Source: Energy Database.

Water pollution controls at steam-electric units are much less extensive than air pollution controls. Virtually all plants have central treatment facilities to treat a number of relatively low-volume waste streams simultaneously. In addition, some plants have installed ash transport water recirculation systems which are no longer required by federal regulations.

The use of cooling towers or ponds to control thermal discharges is becoming increasingly prevalent. The share of capacity with cooling systems increases from less than one-third of pre-1972 capacity to two-thirds of 1977-1979 capacity (Table IV-5). This shift reflects both environmental requirements and an increasing proportion of units sited in water-constrained areas where recirculating cooling systems are used primarily for economic rather than environmental reasons.

Table IV-5

DISTRIBUTION OF FOSSIL-FUEL CAPACITY BY THERMAL CONTROL STRATEGY[1]

(percent of age-category capacity)

	Pre-1972	1972-1976	1977-1979
With cooling tower or pond	26	63	66
Without cooling tower or pond	74	37	33

[1]Totals may not add to 100% due to rounding.

Source: Energy Database.

Pollution Control Costs

The average annualized cost of pollution control at fossil-fuel plants is 3.88 mills per kWh of generation (Figure IV-1), although differences in plant age, capacity, fuel type, control strategies, control levels, and other important variables lead to a range of less than 1 mill/kWh to nearly 8 mills/kWh. The dominant contributor to the average cost is control of SO_2 emissions, which accounts for 2.72 mills per kWh or 70 percent of total pollution control expenditures of 3.88 mills/kWh. The remaining pollution control expenditures are relatively evenly divided among controls for TSP emissions and chemical and thermal discharges. By cost component the largest single component of pollution control cost is a premium paid by utilities for low-sulfur fuels. This premium accounts for nearly 65 percent of the average cost of pollution control, and contributes more than three times as much as do capital expenditures to pollution control costs.

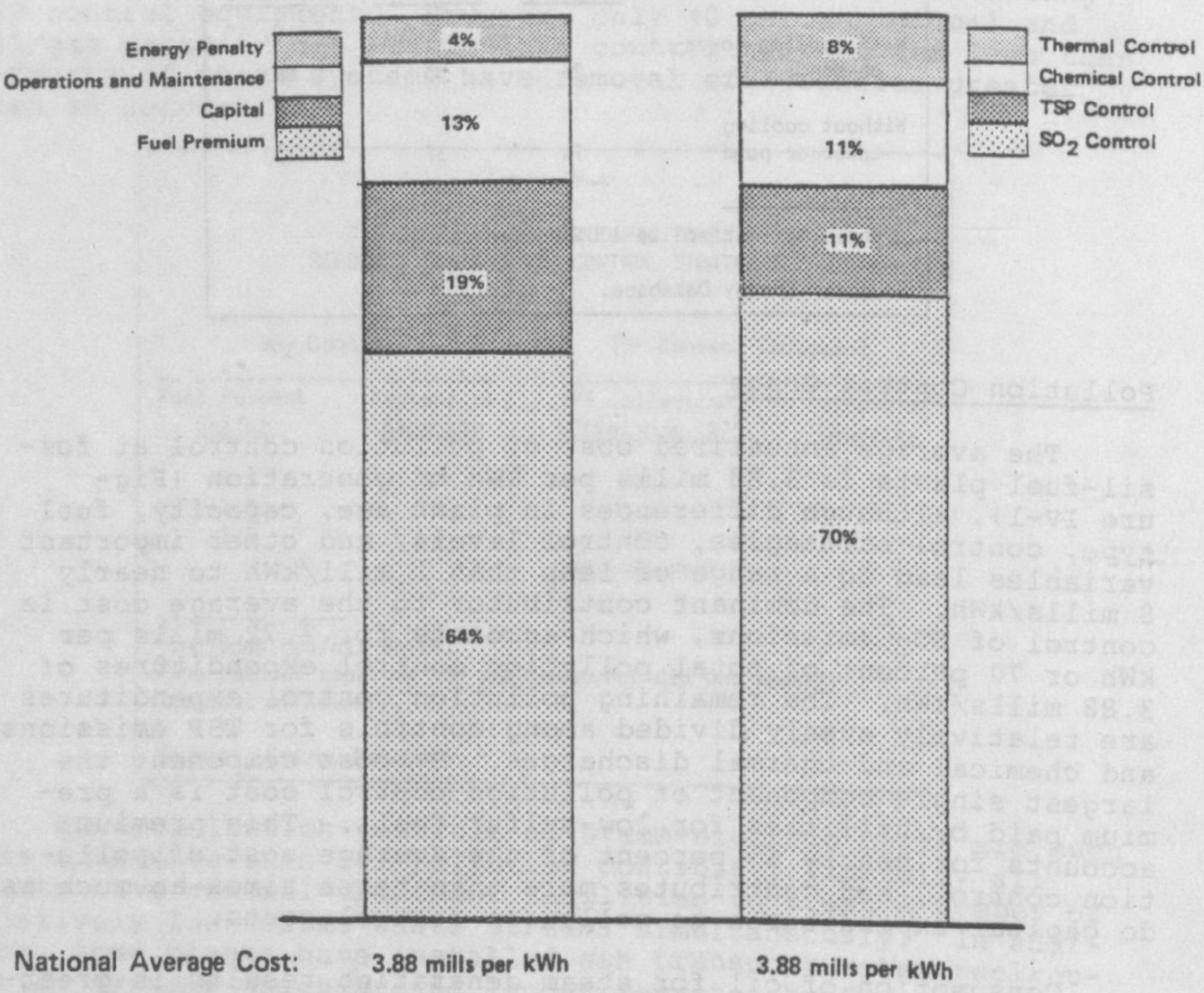
Consumption of oil for steam generation results in greater pollution control expenditures than does consumption of coal or gas because of the premium paid by utilities for low-sulfur oil (Figure IV-2).[3] The average 6.86 mills per kWh

[3]There are a number of ways of calculating the fuel premium. Nonetheless, even if the methodology used in this report somewhat overstates the oil premium, this basic conclusion holds under alternative methods of calculating the premium.

Figure IV–1

COMPONENTS OF 1979 AVERAGE COST OF POLLUTION CONTROL FOR FOSSIL FUEL UNITS

1979 DOLLARS

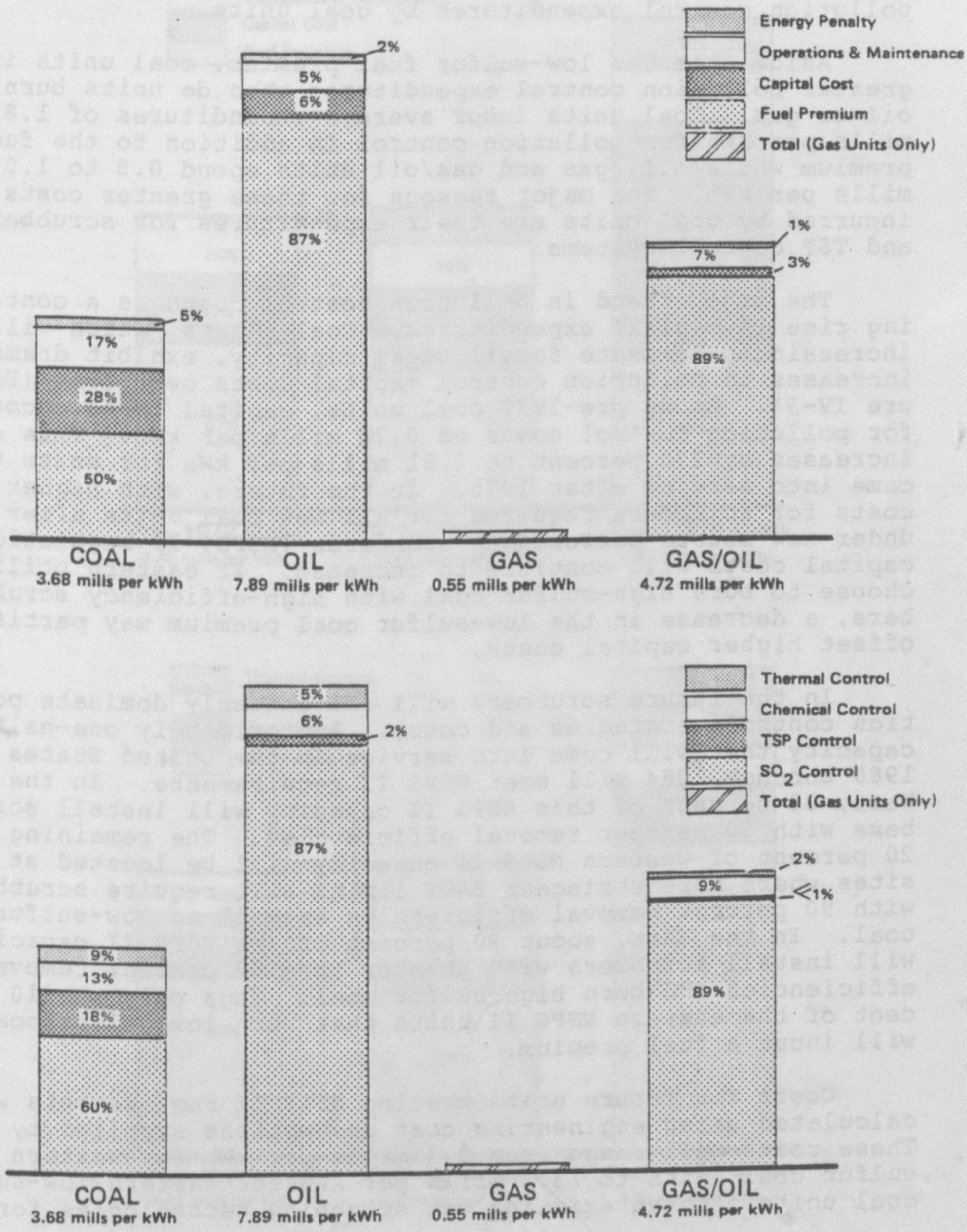


Source: Energy Database; TBS calculations.

Figure IV–2

COMPONENTS OF 1979 NATIONAL AVERAGE COST OF POLLUTION CONTROL FOR FOSSIL FUEL UNITS BY FUEL TYPE

1979 DOLLARS



Source: Energy Database; TBS calculations.

paid by utilities for low-sulfur oil is more than 3.5 times as great as the low-sulfur coal premium and it exceeds total pollution control expenditures by coal units.

Aside from the low-sulfur fuel premium, coal units incur greater pollution control expenditures than do units burning oil or gas. Coal units incur average expenditures of 1.85 mills per kWh for pollution control in addition to the fuel premium while oil, gas and gas/oil units spend 0.5 to 1.0 mills per kWh. The major reasons for these greater costs incurred by coal units are their expenditures for scrubbers and TSP control systems.

The major trend in pollution control costs is a continuing rise in capital expenditures. Coal plants, which will increasingly dominate fossil-steam capacity, exhibit dramatic increases in pollution control capital costs over time (Figure IV-3). Among pre-1972 coal units, capital costs account for pollution control costs of 0.76 mills per kWh. This cost increases by 270 percent to 2.81 mills per kWh for units that came into service after 1976. In the future, with higher costs for scrubbers required for all new coal units after 1985 under new source performance standards (NSPS) II regulations, capital costs will continue to increase. If eastern utilities choose to burn high-sulfur coal with high-efficiency scrubbers, a decrease in the low-sulfur coal premium may partially offset higher capital costs.

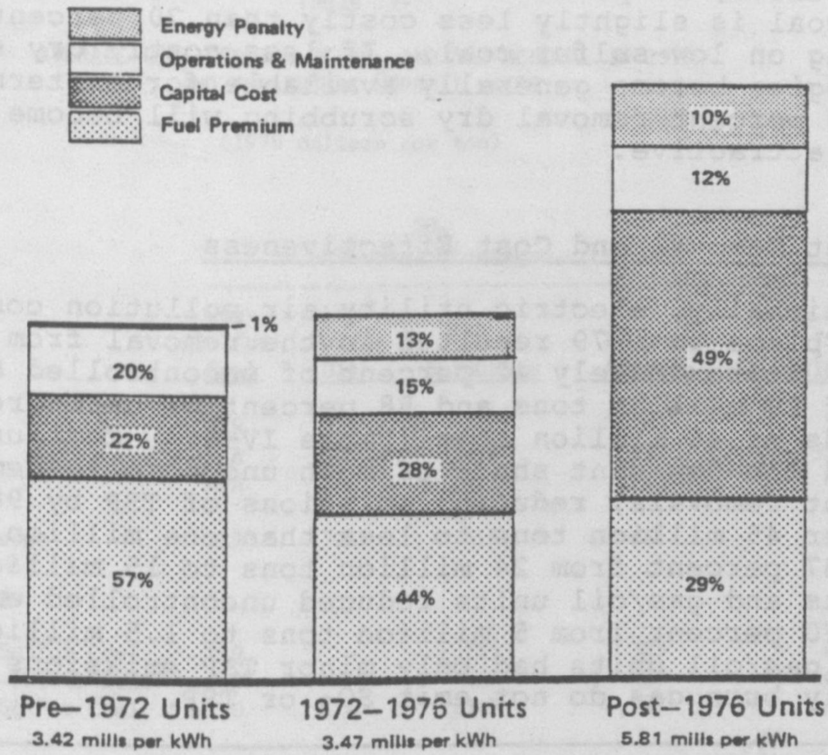
In the future scrubbers will increasingly dominate pollution control strategies and costs. Approximately one-half the capacity that will come into service in the United States from 1980 through 1984 will meet NSPS II requirements. In the West, 80 percent of this NSPS II capacity will install scrubbers with 70 percent removal efficiencies. The remaining 20 percent of western NSPS II capacity will be located at sites where more stringent BACT limits will require scrubbers with 90 percent removal efficiencies as well as low-sulfur coal. In the East, about 90 percent of the NSPS II capacity will install scrubbers with greater than 90 percent removal efficiencies and burn high-sulfur coal. Thus only the 10 percent of the eastern NSPS II units that burn low-sulfur coal will incur a fuel premium..

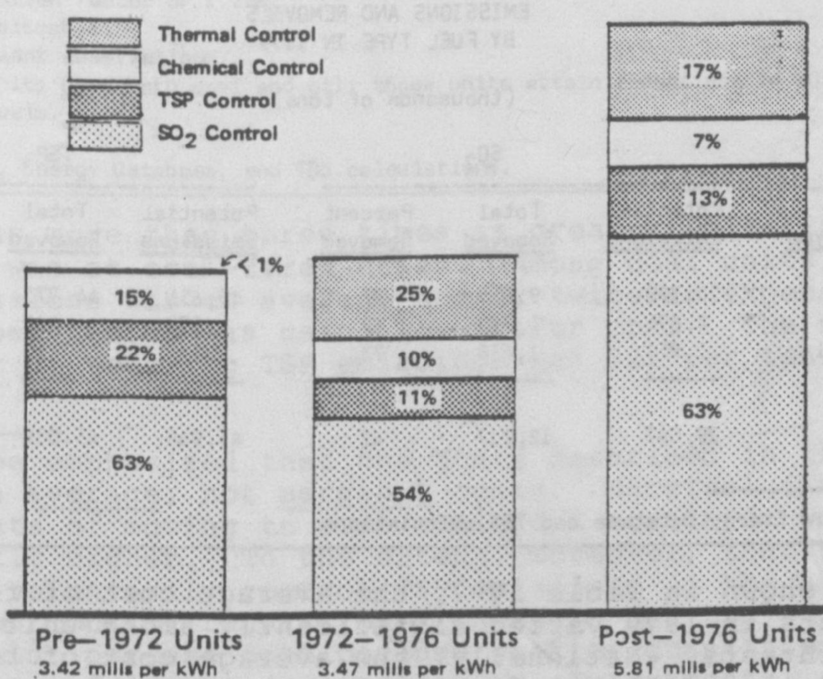
Costs for future units meeting NSPS II requirements were calculated using engineering cost assumptions supplied by EPA. These costs will range from 9.4 mills per kWh for western low-sulfur coal units to 13.4 mills per kWh for eastern low-sulfur coal units. Given existing wet scrubbing technologies for

Figure IV-3

COMPONENTS OF 1979 NATIONAL AVERAGE COST OF POLLUTION FOR COAL UNITS BY AGE CATEGORY

1979 DOLLARS





Source: Energy Database; TBS calculations.

eastern units, 90 percent removal scrubbing on eastern high-sulfur coal is slightly less costly than 70 percent removal scrubbing on low-sulfur coal. If less costly dry scrubbing technologies become generally available for eastern low-sulfur coal, 70 percent removal dry scrubbing will become economically more attractive.

Pollutant Removal and Cost Effectiveness

Nationally, electric utility air pollution control measures in place in 1979 resulted in the removal from the atmosphere of approximately 42 percent of uncontrolled SO_2 emissions of 29 million tons and 98 percent of uncontrolled TSP emissions of 46 million tons (Table IV-6). Coal units contributed the dominant share of both uncontrolled emissions and pollutant removals, reducing emissions of TSP by 98 percent from over 45 million tons to less than one million tons and SO_2 by 37 percent from 24 million tons to 15 million tons. Oil units and gas/oil units reduced uncontrolled emissions of SO_2 by 70 percent from 5 million tons to 1.5 million tons. Oil and gas/oil units had only minor TSP emissions and units that only burn gas do not emit SO_2 or TSP.

Table IV-6

TOTAL NATIONAL POTENTIAL AIR POLLUTANT EMISSIONS AND REMOVALS BY FUEL TYPE IN 1979

(thousands of tons)

	SO_2			TSP		
Fuel Type	Potential Emissions	Total Removed	Percent Removed	Potential Emissions	Total Removed	Percent Removed
Coal	24,398	9,015	37	45,651	44,775	98
Oil	2,695	1,783	68	170	143	84
Gas/Oil	1,954	1,418	73	127	100	79
Total	29,047	12,217	42	45,948	45,018	98

Source: Energy Database and TBS calculations.

As shown in Table IV-7, the average cost of removing pollutants in 1979 varied significantly among unit categories and pollutants. Nationally, the average cost of reducing SO_2 emissions was $461 per ton. The cost of reducing these

Table IV-7

AVERAGE COST PER TON OF SO_2 AND TSP REMOVAL IN 1979 AND FOR FUTURE NSPS II UNITS

(1979 dollars per ton)

Fuel Type	SO_2 Removal Strategy				
1979 Generation	Low-Sulfur Coal	Low-Sulfur Oil	Scrubbers	Weighted Average	TSP Equipment
Coal	229	412	418	263	20
Oil	N/A	737	N/A	737	534
Gas/Oil	N/A	742	N/A	742	a
National Average	229	721	418	461	22
NSPS II Units					
Eastern Low-Sulfur Coal	219	-	1,145	385	80
Eastern High-Sulfur Coal	0	-	417	417	47
Western Low-Sulfur Coal	0	-	1,347	1,347	67

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

N/A = Not applicable.

a = Insufficient observations.

[1]Some coal units burn both coal and oil; these units attain reductions in SO_2 from both fuels.

Source: EPA, Energy Database, and TBS calculations.

emissions was more than three times as great at oil-fired units as it was at coal-fired units. Among coal units, reducing SO_2 emissions was on average nearly twice as expensive using scrubbers as it was using low-sulfur coal. The national average cost of reducing TSP emissions was \$22 per ton.[4] This

[4]It should be emphasized that the costs described in this chapter are average, not marginal costs. Marginal (incremental) costs of moving to more stringent standards would be significantly higher. To the extent, moreover, that utilities would voluntarily control TSP emissions in the absence of pollution control regulations, the cost per ton of TSP removal would increase both because smaller quantities of TSP would be removed in response solely to environmental regulations and because costs would be based on the marginal costs of control systems whose efficiency exceeds the levels that would be adopted voluntarily.

average cost was dominated by the low average cost of removing very large quantities of TSP at coal-fired units. Removal costs for future, NSPS II, units are dominated by scrubbers and are projected to be significantly greater than costs at existing units. On a total national average removal cost basis, SO_2 and TSP removal costs will at least double or triple.

The unit-level analysis is described below in three sections. The first section discusses the research approach and data sources used in the analysis. The second section contains a description of the unit categories selected for analysis and highlights the strategies used by units in each category to meet environmental regulations. The third section contains the results of the cost analysis, comparing pollution control costs both among unit categories and within these categories. In this third section, unit-level costs that may be incurred under future regulations are also discussed. The final section of the chapter discusses quantities of pollutants removed and the costs per ton of removal.

RESEARCH METHODOLOGY AND DATA SOURCES

The unit-level analysis is based on actual compliance strategies and costs for fossil-fired steam electric units. These data are compiled in the Energy Database from Form 67 submittals to the Department of Energy for 1979 and were validated extensively prior to including them in this study. The analysis was performed in four steps. First, units in the Energy Database were categorized according to the two parameters that most significantly affect their environmental compliance strategies and costs--fuel type and age. Next, strategies used by units in each category to comply with environmental regulations were examined. Third, 1979 compliance costs at the individual unit level were determined on the basis of reported environmental expenditures and, in a limited number of instances, engineering cost estimates. Finally, unit-level costs for units that will be coming into service in the future were estimated from engineering cost estimates provided by EPA.

The Energy Database contains 2,277 units with a capacity of 395,868 MW, representing approximately 96 percent of the total fossil-fuel-fired generating capacity in the United States. The analysis of industry compliance strategies is based on this full database. Data compiled in the Energy Database were validated for reasonableness and consistency and compared with external sources such as DOE's Generating Unit Reference File, for 1979, and Cost and Quality of Fuels, for 1979, and the National Coal Association's Steam Plant Factors. In most instances it was possible to correct anomalous entries in the Database (generally unreasonable heat rates that indicate incorrectly reported fuel consumption or generation of electricity). Form 67s for units representing approximately 8 percent of fossil-fuel capacity, however, contained incomplete or anomalous data that could not be verified. Where necessary, these units were eliminated from the analysis and, consequently, the results presented in this chapter are based on a sample of at least 88 percent of total capacity.[5]

Environmental compliance strategies and costs vary with a unit's age and the type of fuel it uses. For this reason the units in the Energy Database were allocated among 12 unit categories based on fuel type and plant age. Four fuel categories--coal, gas, oil, and gas/oil--and three age categories --units in service before 1972, between 1972 and 1976, and after 1976--were selected. The distribution of units and capacity among these categories is shown in Table IV-8.

Table IV-8

DISTRIBUTION OF UNITS BY UNIT CATEGORIES

In-Service Year	Coal		Oil		Gas		Gas/Oil		Total Fossil		Nuclear	
	Units	MW	Units	MW	Units	MW	Units	MW	Units	MW	Units	MW
Pre-1972	898	141,377	312	29,212	330	36,800	417	45,201	1,957	252,590	18	8,642
1972-1976	108	60,437	48	19,251	34	11,862	20	7,616	210	99,166	40	34,806
1977-1979	72	32,734	22	10,341	12	3,855	4	371	110	47,301	12	10,247
Total	1,078	234,548	382	58,804	376	52,517	441	53,188	2,277	399,057	70	53,695

Source: Energy Database for fossil-fuel data and Generating Unit Reference File (GURF DOE) for nuclear fuel data.

[5]The analysis of compliance costs was performed on a smaller sample representing approximately 69 percent of the total capacity in the Database, of which 9 percent was eliminated because of anomalous data. Subsequent to the completion of the cost analysis described in this chapter, Form 67 data for the remaining units were compiled in the Energy Database. An analysis of cost data for these remaining units indicates that there are no substantial differences between these units and those on which this chapter's cost analysis is based.

Units in the Energy Database do not fall neatly into fuel categories: only one-third burn exclusively coal, oil, or gas.[6] Consequently it was necessary to develop a number of decision rules to allocate units among the four fuel categories.

All units that burned appreciable quantities of coal in 1979 were considered coal units. These units, as shown in Table IV-8, account for one-half of the units and nearly 60 percent of the capacity. Frequently these units burn some oil or gas as starter fuel. Fewer than 2 percent of the coal-fired units also burn oil or gas beyond that used for start-up.

Coal-fired units that also burn oil or gas were not differentiated in the analysis for two major reasons. First, given the high cost of burning oil or gas as compared with that of coal, units capable of burning coal can be expected to use coal as their fuel source to the maximum extent possible. Second, in terms of environmental compliance, these units are more similar to other coal units than to oil or gas units.

Because of their distinct differences in environmental compliance costs, units burning oil and gas are differentiated. Oil-fired units, which account for 15 percent of the total capacity, incur significant environmental compliance costs as a result of burning low-sulfur oil. They also incur some costs to operate TSP control systems. By contrast, gas-fired units, which make up 13 percent of total capacity, have low compliance costs because, unlike oil and gas units, they are not affected by TSP, SO_2, and certain chemical standards.

A further 13 percent of the total capacity consists of units that burn a combination of oil and gas, with neither fuel accounting for more than 95 percent of the unit's total. As oil units, these units bear significant environmental compliance costs. To the extent that they burn gas, however, their average costs per kilowatt-hour are diluted by the very

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[6] Units in the Energy Database fall into seven fuel categories which were compressed into the four categories used in this analysis: 270 units with 40,768 MW burn coal exclusively; 528 units with 149,823 MW burn coal and oil; 116 units with 18,882 MW burn coal, oil, and gas; 164 units with 25,075 MW burn coal and gas; 347 units with 51,763 MW burn oil exclusively; 227 units with 20,443 MW burn gas exclusively; and 625 units with 88,766 MW burn oil and gas.

minor compliance costs they incur when they burn gas. Because there is no ready way to disentangle the oil and gas costs that gas/oil units bear, this analysis considers them in a single mixed category.

Nuclear units do not submit Form 67s and are regulated primarily by the Nuclear Regulatory Commission. For these reasons compliance strategies and costs for nuclear units are not considered separately in the unit-level analysis. Both strategies and costs, however, are similar to those for gas units because nuclear units are not affected by EPA air regulations, and nuclear unit waste streams affected by EPA water regulations are similar to those for gas units.

The analysis divides the steam-electric units into the following age categories:

- Units in service before 1972. These units antedate regulations under the Clean Air and Clean Water Acts and have complied with these regulations by retrofitting pollution control equipment.

- Units with in-service dates between 1972 and 1976. These units do not qualify as new units for regulatory purposes, but generally were designed taking air and water regulations into account.

- Post-1976 units. These units are generally considered new sources under both air and water regulations. They do not fall, however, under the revised new source performance standards for air, which apply only to units beginning construction after September 18, 1978.

On the average the in-service dates for pre-1972 units are in the early 1960s and those for 1972-1976 and post-1976 units are in the midpoints for their age categories.

UNIT COMPLIANCE STRATEGIES

As noted in Chapter II federal environmental regulations affecting the electric utility industry have focused on air pollution resulting from SO_2 and TSP emissions and on water pollution caused by chemical and thermal discharges. Until recently NO_x emissions and electric utility solid wastes have not been the subject of major regulatory attention, although EPA will most likely direct increasing attention to both areas.[7]

A utility's financial condition, its fuel purchasing arrangements, and its anticipation of future developments, as well as a unit's age and fuel type, can affect its choice of environmental compliance strategies. In the case of utilities facing financial constraints, the compliance strategy selected may not always minimize annualized costs. Such utilities may have to adopt a strategy that minimizes capital requirements, rather than total annual revenue requirements. For example, a capital-constrained utility earning an inadequate return on its investments may be unable to finance an investment in scrubbers and may have to burn low-sulfur coal instead. Existing fuel contracts also affect compliance strategies. Utilities with long-term arrangements for high-sulfur coal supplies are more likely to pursue an equipment-intensive strategy than utilities without such contracts. Utilities anticipating more stringent future requirements may incur higher costs than required in the short run in order to avoid future expenses for retrofitting pollution control equipment.

Air Pollution Control Strategies

Air pollution controls, implemented through state implementation plans, for existing units in nonattainment areas must comply with reasonably available control technology (RACT) for units that commenced construction prior to the 1971 NSPS I date. In this analysis, in-service dates of 1976 or earlier are considered existing units with respect to NSPS I requirements. Standards under RACT are determined on a case-by-case basis and depend both on local environmental conditions and on economic considerations. All units that commenced construction after 1971 have generally been required to comply with technology-based performance standards established by EPA in 1972. These standards specify emission limits for air pollutants that may be met either by burning cleaner fuels

[7]Two trends apparent in the Energy Database are the decreasing use of cyclone boilers, which are characterized by very high NO_x emissions, and increasing use of lined solid waste disposal facilities. Cyclone units were widely installed in the 1960s and early 1970s, but have been virtually discontinued in later units. The use of lined disposal facilities is projected to increase by 50 percent for units reporting future plans in their Form 67s.

or by installing pollution control equipment. In this analysis, units with in-service dates of 1977 and later are considered new units subject to NSPS I requirements.

New source performance standards established in 1979 for plants commencing construction after mid-1978 (NSPS II) specify both emission limits and emission reductions that require pollution control equipment. New units in areas that meet national ambient air quality standards are also subject to best available control technology (BACT) requirements. New units in areas that do not meet national standards are subject to lowest achievable emission rate (LAER) requirements. Both BACT and LAER incorporate NSPS as a minimum requirement; however, in specific instances they may be more restrictive than NSPS.

Coal-Fired Unit Strategies

Coal units are potentially major sources of SO_2 and TSP as well as of NO_x emissions. Controls of these emissions have involved the installation of pollution control equipment for SO_2 and TSP control as well as the use of coal with lower sulfur contents for SO_2 control. To date major steps have not been taken to control NO_x emissions, although trends in boiler design reflect a need to reduce NO_x emissions.

SO_2 Control. Approximately 23 percent of the capacity in coal-fired units that came into service before 1977 meets the NSPS I requirement of 1.2 pounds of SO_2 per million Btu. For post-1976 capacity, this figure has risen dramatically to 82 percent, indicating that most units that have come into service since 1976 have been affected by NSPS I. Coal-fired units are relying increasingly on pollution control equipment to control SO_2 emissions. While only about 4 percent of the coal capacity in service before 1977 has flue gas desulfurization (FGD) systems (scrubbers), approximately 36 percent of the capacity that began operating in 1977-1979 has scrubbers, and about 52 percent of the capacity that will come into service in 1980-1984 will use them (see Tables IV-9, IV-10, and IV-11).

Table IV-9

REPORTED SO_2 COMPLIANCE STRATEGIES
PRE-1977 COAL UNITS

FGD Scrubber Efficiency (%)	Sulfur Content of Fuel (percent): <0.8 Units	<0.8 (MW)	0.8-2.0 Units	0.8-2.0 (MW)	>2.0 Units	>2.0 (MW)	Total Units	Total (MW)
96-100	2	(288)	3	(466)	0	(0)	5	(754)
90-95	0	(0)	2	(462)	3	(1,316)	5	(1,779)
70-89	9	(1,831)	0	(0)	20	(1,727)	29	(5,557)
< 70	6	(2,433)	0	(0)	1	(147)	7	(2,590)
Total with FGD	17	(4,562)	5	(928)	24	(5,189)	46	(10,679)
Total without FGD	174	(35,693)	373	(74,559)	413	(80,883)	960	(191,135)
Total	191	(40,255)	378	(75,487)	437	(86,072)	1,006	(201,814)

Source: Energy Database.

Nearly three-quarters of the 1977-1979 capacity that does not have scrubbers burns low-sulfur coal. These units, primarily located in the West, meet the NSPS I standards which specify emissions limits but not SO_2 control equipment removal efficiencies. The remaining units (approximately 18 percent of post-1976 coal-fired capacity) do not comply with NSPS I limitations. Some of these units were commenced before 1971 but did not come into service until after 1976 and are not affected by NSPS I standards. Others are currently violating the limits, but in most cases are on EPA-approved compliance schedules.

Coal units coming into service in the future will meet increasingly stringent standards. Forty-eight percent of the capacity coming into service in 1980-1984 will meet the NSPS II requirements and all remaining post-1979 units will meet NSPS I standards.[8] As shown in Table IV-11, future units will increasingly rely on FGD systems to comply with SO_2

[8] NSPS II standards apply to units commenced after 1978. Some of these units will come into service in 1980-1984 while other units coming into service in 1980-1984 will be subject to NSPS I because construction on them commenced before 1979.

Table IV-10

REPORTED SO_2 COMPLIANCE STRATEGIES
1977-1979 COAL UNITS

FGD Scrubber Efficiency (%)	Sulfur Content of Fuel (percent) <0.8 Units	<0.8 (MW)	0.8-2.0 Units	0.8-2.0 (MW)	>2.0 Units	>2.0 (MW)	Total Units	Total (MW)
96-100	0	(0)	0	(0)	0	(0)	0	(0)
90-95	2	(1,059)	0	(0)	3	(2,109)	5	(3,168)
70-89	8	(2,705)	2	(510)	3	(1,208)	13	(4,423)
<70	7	(3,528)	1	(280)	1	(12.5)	9	(3,820)
Total with FGD	17	(7,292)	3	(790)	7	(3,329)	27	(11,411)
Total without FGD	30	(12,350)	9	(5,786)	6	(3,188)	45	(21,323)
Total	47	(19,642)	12	(6,576)	13	(6,517)	72	(32,734)

Source: Energy Database.

Table IV-11

REPORTED SO_2 COMPLIANCE STRATEGIES
1980-1984 COAL UNITS

FGD Scrubber Efficiency (%)	Sulfur Content of Fuel (percent) <0.8 Units	<0.8 (MW)	0.8-2.0 Units	0.8-2.0 (MW)	>2.0 Units	>2.0 (MW)	Total Units	Total (MW)
96-100	0	(0)	0	(0)	0	(0)	0	(0)
90-95	3	(2,062)	0	(0)	10	(5,781)	13	(7,843)
70-89	3	(1,315)	4	(2,603)	2	(999)	9	(4,917)
<70	0	(0)	0	(0)	0	0	0	(0)
Total with FGD	6	(3,377)	4	(2,603)	12	(6,780)	22	(12,760)
Total without FGD	38	(11,315)	2	(510)	0	0	40	(11,825)
Total	44	(14,692)	6	(3,113)	12	(6,780)	62	(24,585)

Source: Energy Database.

standards. Fifty-two percent of the coal-fired capacity coming into service in the 1980-1984 period will have FGD systems. With the exception of a few western units that meet stringent PSD limits, units with FGD systems that burn medium-to low-sulfur coal will have scrubbers with removal efficiencies of 70 to 80 percent. Conversely, units that burn high-sulfur coal will have scrubbers whose removal efficiency is 90 percent or greater. This split reflects the sliding scale standard contained in the NSPS II regulations which allows plants burning low-sulfur coal to install scrubbers with 70 percent removal efficiencies, but requires 90 percent removal efficiencies at units burning high-sulfur coal.

All but one of the eastern units coming into service from 1980 through 1984 and meeting the NSPS II limits will burn high-sulfur coal. This fact indicates that, given current scrubber technologies and costs, plants locating in the East do not have an incentive to burn low-sulfur coal to avoid a 90 percent scrubbing requirement. For these eastern units the fuel premium associated with low-sulfur coal outweighs potential savings from the use of less costly FGD systems with 70 percent removal efficiencies.

TSP Control. Strategies for complying with TSP standards reflect a tightening of standards similar to that observed in SO_2 controls, although the shift from earlier to later compliance strategies is less dramatic. In the mid-1970s, electrostatic precipitators with collection efficiences greater than 98 percent were retrofitted on units and operate in conjunction with older mechanical collection systems. Units that have come into service since 1972 generally have been built with high-efficiency electrostatic precipitators; the most recent units have electrostatic precipitators or baghouses with collection efficiencies of 99.6 percent. As a result, about 96 percent of the capacity that came into service before 1977 now has TSP collection systems with removal efficiencies greater than 98 percent and about 97 percent of the post-1976 capacity has such systems (see Table IV-12).

Future SO_2 and TSP Controls on Existing Units. Data in the Energy Database concerning future compliance actions for units that currently are in operation indicate that 76 percent of coal-fired units are in compliance with current SO_2 standards and 87 percent with TSP standards. As shown in Table IV-13, one-fourth of the units that are not in compliance with SO_2 standards will meet the standards by changing fuels, while slightly less than one-fourth will retrofit scrubbers. More than two-thirds of the units that do not comply with TSP

Table IV-12

REPORTED COAL UNIT
TSP COMPLIANCE STRATEGIES

TSP Collection Efficiency (%)	Pre-1977 Units Number of Units	Pre-1977 Units MW	Post-1976 Units Number of Units	Post-1976 Units MW
>98	797	182,542	59	26,936
95-98	49	3,660	1	650
90-95	42	2,705	0	0
<90	44	2,027	1	235
Total[1]	932	190,934	61	27,821

[1]75 units with 15,793 MW of capacity did not report TSP control efficiencies.

Source: Energy Database.

standards will retrofit more efficient TSP control equipment. In addition, as also shown in Table IV-13, some units will be derated or retired to comply with air regulations and a relatively small number of units will seek legal remedies--variances or litigation.

Oil-Fired Unit Strategies

Oil-fired units emit both SO_2 and TSP in lesser quantities than do coal-fired units. Control of SO_2 emissions at oil-fired units is achieved exclusively through the use of low-sulfur oil while particulate emissions are decreased both by burning low-sulfur oil and by installing TSP control equipment. Although the use of low-sulfur oil also results in decreased TSP emissions, it is a much more costly method of TSP control than installing electrostatic precipitators. Consequently, oil-fired units burn low-sulfur oil primarily to reduce SO_2 emissions and reductions in TSP emissions from low-sulfur oil are incidental to SO_2 control.

Nearly 30 percent of oil-fired capacity burns oil that contains less than 0.3 percent sulfur by weight and over 60 percent of the capacity burns oil with less than 1.0 percent sulfur. Units that burn very low sulfur oil are frequently older units located in heavily industrialized and populated areas that have not met the National Ambient Air Quality Standards (Table IV-14).

Table IV-13

FUTURE SO_2 AND TSP COMPLIANCE STRATEGIES BY EXISTING COAL UNITS[1]

Strategies	SO_2 (percent of units)	TSP (percent of units)
Currently in Compliance	76	87
Will Change Fuel	6	0
Will Retrofit Pollution Control Equipment	5	9
Derate or Retire	2	2
Legal Remedy	4	1
Not Specified	7	1

[1]An additional 2 percent of units will use lower sulfur fuels and install scrubbers; these units are listed as installing equipment.

Source: Energy Database.

Table IV-14

REPORTED SO_2 COMPLIANCE STRATEGIES OIL UNITS[1]

Percent Sulfur in Fuel	Number of Units	Capacity (MW)
<0.3	185	30,183
0.3-0.4	146	17,029
0.5-0.9	179	23,224
1.0-1.4	135	17,349
1.5-1.9	110	15,550
2.0-2.5	60	6,917
>2.5	8	1,740
Total	823	111,992

[1]Includes gas/oil units that burn substantial quantities of oil.

Source: Energy Database.

Particulate control systems, which are present at all coal units, exist only on approximately 40 percent of oil-fired capacity (see Table IV-15). Since uncontrolled TSP emissions from oil combustion are lower than those for coal combustion, removal efficiencies for TSP control systems are generally lower for oil-fired than for coal-fired units. Less than 10 percent of oil-fired capacity has systems with removal efficiencies greater than 98 percent and nearly one-half have efficiencies of less than 90 percent.

Table IV-15

REPORTED TSP COMPLIANCE STRATEGIES
EXISTING OIL UNITS

Tsp Collection Efficiency (%)	Number of Units	Capacity (MW)
>98	34	9,128
96-98	51	7,886
90-95	77	11,688
<90	96	15,655
Total with TSP control[1]	274	45,526
Total without TSP control	549	66,466
Total	823	111,992

[1]Includes 16 units with 1,169 MW reporting TSP controls but not reporting control efficiencies.

Source: Energy Database.

Water Pollution Control Strategies

The water discharges from electric utilities are regulated by two general categories of environmental regulations--chemical and thermal. The promulgation in late 1974 of effluent limitation guidelines required new and existing units to control chemical pollution by using best practicable control technology (BPT). Occasionally since then the Agency has attempted to revise the 1974 guidelines. However, legal challenges and reevaluations of regulations by the Agency itself have precluded all but a few substantive changes in the regulations. In addition, since 1977 the courts have remanded federal thermal discharge regulations, and consequently, the implementation of Section 316(a) of the Clean Water Act, which requires thermal pollution controls, has been up to individual permit writers applying best engineering judgments on a case-by-case basis.

More and more electric utilities are using cooling towers or ponds to control thermal discharges. While less than 30 percent of the steam-electric capacity that has been in service since before 1972 has cooling towers or ponds, more than 60 percent of the post-1976 capacity uses these systems (Table IV-16). This increasing use of thermal control systems is not solely due to environmental requirements. Recent capacity additions have been heavily concentrated in the West where water-supply constraints frequently require the use of cooling towers. Siting for units located in the East has also been determined increasingly by other considerations such as air quality. Consequently, it has become more difficult to locate sites that have plentiful cooling water and meet other siting criteria.

Because the Form 67s offer no data concerning strategies and costs of compliance with chemical discharge guidelines, it was not possible to identify unit-level compliance strategies by using the Energy Database. Instead, for purposes of the cost analysis TBS assumed that all units meet the 1974 BPT guidelines which require sedimentation of bottom- and fly-ash transport water, removal of oil and grease from various low-volume waste streams at a central treatment facility, and minimization of cooling-water chlorine discharges through management practices. This approach somewhat understates costs because some units have complied with requirements for recirculation of bottom-ash transport water established in 1975 but rescinded in 1980. The cost analysis is not sensitive to the assumption that all units meet BPT limits because the cost of these systems on a unit basis is approximately one-fourth that of a recirculating cooling system and an even

Table IV-16

TRENDS IN COOLING TOWER USE

Technology	Pre-1972 Units	Pre-1972 Capacity(MW)	1972-1976 Units	1972-1976 Capacity(MW)	1977-1979 Units	1977-1979 Capacity(MW)
Coal-Fired Units						
With cooling tower or pond	201	38,999	82	45,112	55	21,404
Without cooling tower or pond	660	101,063	21	11,119	12	11,329
Oil-Fired Units						
With cooling tower or pond	14	925.8	17	5,917	13	6,927
Without cooling tower or pond	298	28,286	31	13,334	9	3,414
Gas-Fired Units						
With cooling tower or pond	213	25,680	22	7,945	9	2,516
Without cooling tower or pond	117	11,120	12	3,917	3	1,339
Gas/Oil Fired Units						
With cooling tower or pond	107	7,833	8	1,788	4	371
Without cooling tower or pond	310	37,368	12	5,828	0	0
Nuclear Units						
With cooling tower or pond	4	2,375	15	13,299	6	5,175
Without cooling tower or pond	14	6,268	25	21,507	6	5,071

Source: Energy Database (coal, oil, and gas units) and GURF (nuclear units).

smaller fraction of the cost of TSP or SO_2 control systems. The cost of recirculation systems for ash transport water, on the other hand, is substantial and to the extent that utilities have complied with this requirement they have incurred costs for water pollution control that are higher than those imposed by current regulations.

Solid-Waste Control Strategies

The electric utility industry is expected to generate greatly increased volumes of solid wastes over the next decade for two reasons. First, new coal capacity, which generates large amounts of solid waste, will displace oil and gas capacity. Second, since air regulations are becoming increasingly stringent, TSP and SO_2 removed from stack gases will ultimately become fly ash and scrubber sludge requiring disposal. However, to the extent that dry SO_2 scrubbing becomes a generally accepted technology, smaller quantities of more easily handled dry residues will require disposal.

Compliance with solid waste regulations will vary as a function of natural conditions and local regulations. Currently, utility solid wastes are regulated by individual state regulations. In the future utility solid wastes will in all probability be considered nonhazardous. Federal regulations governing nonhazardous solid waste disposal establish minimum criteria for solid waste disposal facilities, but individual states develop and implement solid waste disposal regulations. Consequently, regulations in states that have impermeable soils and do not depend on ground water are not likely to require major changes from current practices. Conversely, states with permeable soil, extensive ground water aquifers, and floodplains may require major changes from current practices. Such changes could involve clay or synthetic liners for disposal facilities, diking as protection against flooding, or increased transport distances to environmentally acceptable disposal sites.

1979 UNIT-LEVEL COSTS

Once the units in the Energy Database were categorized according to their in-service dates and fuel types, and once pollution control strategies were analyzed, it was possible to develop unit-level costs. This section reviews first the technical and financial assumptions necessary to translate the costs reported in the Energy Database into annualized costs on a per-kilowatt-hour basis. Second, it reports the results of the analysis of costs and cost-effectiveness for units represented in the Energy Database. Finally, it presents a model-unit analysis of possible unit-level costs under future environmental regulations. This model-unit analysis is based on engineering cost estimates provided by EPA, rather than on data from the Energy Database which are based on actually incurred engineering costs.

Technical and Financial Assumptions

This section discusses the assumptions used in the unit-level analysis to calculate (1) the costs to the electric utility industry of complying with pollution control regulations and (2) the baseline costs of operating units without such restrictions.

Pollution Control Assumptions

A number of assumptions were necessary to translate costs reported in the Form 67s into annualized pollution control costs per kWh of generations. These assumptions concerned technical and financial issues such as capital charges for pollution control equipment, low-sulfur fuel premiums, capacity and energy penalties, pollution control costs not reported or reflected in the Form 67s, generation-related costs, and compliance status.

Capital Charges. Capital charges for pollution control equipment were annualized to obtain level pretax revenue requirements over an investment life of 20 years. A capital recovery factor of 19 percent was used, based on an amortization of the investment over 20 years at the weighted-average marginal cost of capital during the 1973-1979 period of 18.32 percent.

Plausible alternative assumptions concerning capital recovery factors do not change total capital charges by more than 5 percent (see Table IV-17). In some cases the lifetime of pollution control equipment exceeds 20 years. Increasing

Table IV-17

SENSITIVITY OF CAPITAL COST AND INVESTMENT LIFE ASSUMPTIONS USED IN THE UNIT-CATEGORY ANALYSIS

Cost of Capital (%)	Investment Life (years)	Capital Recovery Factor (%)	Cost[1] (mills/kWh)	Percent Change in Cost per kWh
18.32	20	18.98	3.61	
18.32	30	18.44	3.51	(2.93)
18.32	45	18.33	3.49	(3.55)
19.32	20	19.90	3.79	4.62
19.32	30	19.42	3.69	2.14
19.32	45	19.33	3.68	1.87

[1]Cost of $100 per kilowatt investment at a 60 percent capacity factor.

Source: TBS calculations.

the investment lifetime to 30 years results in a 2.9 percent (0.1 mill) decrease in the pollution control equipment cost per kWh. Conversely, raising the cost of capital by 1.0 percent to reflect higher interest rates that have existed since 1979 would increase the cost of capital equipment by 4.6 percent (0.18 mills/kWh).

Low-Sulfur Fuel Premiums. Fuel premiums for low-sulfur coal and oil were developed using data on costs of fuel delivered to steam-electric plants compiled by DOE from 1979 Form 423s. It was assumed that the differential between the cost of coal or oil with less than 3 percent sulfur and that of coal and oil with more than 3 percent sulfur is a premium attributable to regulations limiting SO_2 emissions (see Figure IV-4). Potential emissions were also calculated assuming that oil-fired units would burn 3 percent sulfur oil in the absence of environmental regulations, that coal-fired units in the East would use sulfur with 3 percent or more sulfur, and that units in the West would use 1 percent sulfur coal. The low-sulfur coal premium was based on a weighted average of the East North Central, East South Central, and South Atlantic regions. Western regions were not considered in developing coal premiums since virtually all coal deliveries in these regions have low sulfur contents. In the analysis a fuel premium was not attributed to western units.

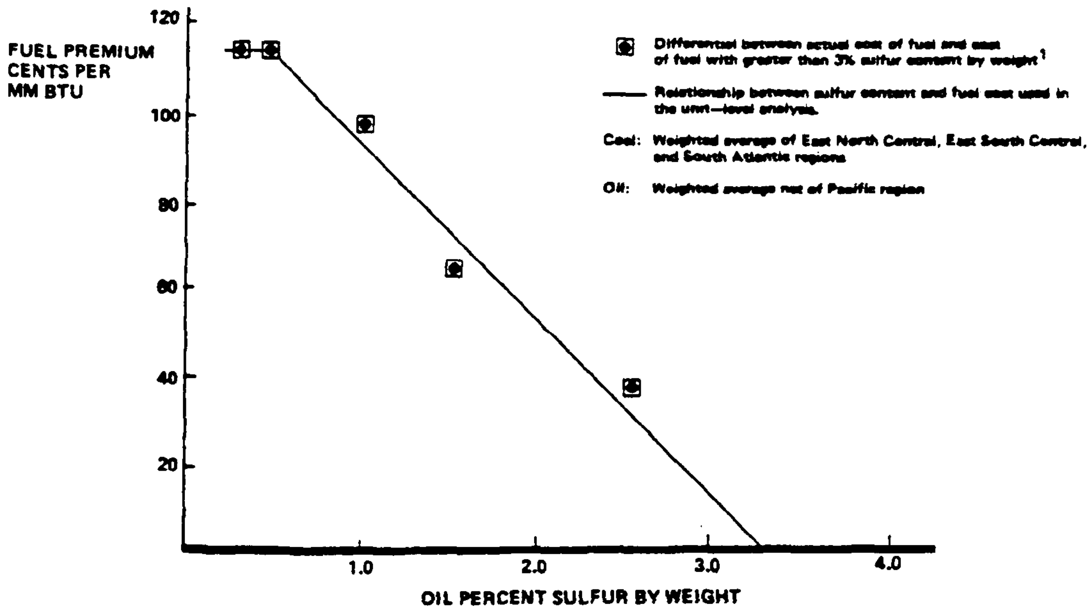
The use of the full differential between high- and low-sulfur coal as the fuel premium probably overstates that premium because of uncertainty concerning the base cost of coal in the absence of environmental regulations. The cost of high-sulfur coal is lower than it would be in the absence of environmental restrictions, which have diminished demand for those fuels. Demand for coal from marginal high-sulfur coal mines has decreased and production of high-sulfur coal has been concentrated in more efficient mines. Conversely, demand for coal from marginal and less efficient mines in areas that produce low-sulfur coal has increased. If the base price of coal were assumed to be the average price of 2 to 3 percent sulfur coal reported in the Cost and Quality of Fuels, the fuel premium for 1 percent sulfur coal would decrease by about 25 percent.

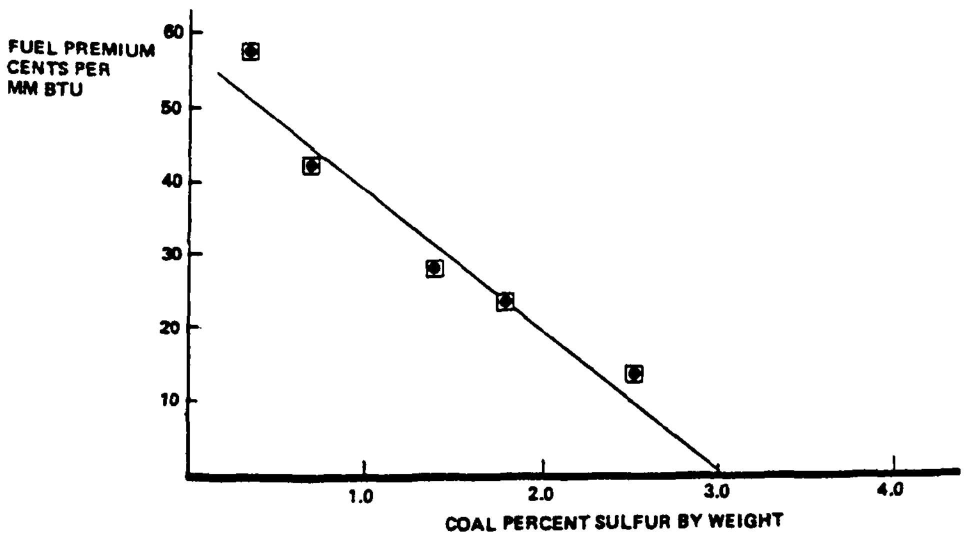
Similarly the price that utilities would pay for oil if there were no environmental regulations is probably higher than the price they currently pay for 3 percent sulfur oil. A relatively small portion of oil consumed by steam-electric utilities has a sulfur content greater than 3 percent, and it could be argued that the average cost of 2 to 3 percent sulfur

Figure IV—4

LOW—SULFUR FUEL PREMIUMS

1979 DOLLARS





[1] Data reported in Cost and Quality of Fuels are for ranges in sulfur content. Values shown in graph are for midpoint of range; the line was fit using a least-squares approach.

Source: 1979 Cost and Quality of Fuels.

oil reported in the Cost and Quality of Fuels provides a more realistic base price. Alternatively the cost of desulfurization of high-sulfur oil may provide a measure of the magnitude of the oil premium. In either of the above cases, as discussed below, the magnitude of the low-sulfur oil premium would decrease by approximately one-third for 1 percent sulfur oil.

To the extent that environmental regulations will become more stringent in the future, low-sulfur fuel premiums may increase at a faster rate than the GNP deflator. Because marginal low-sulfur coal mines will be increasingly used, the costs of producing low-sulfur coal will rise. But new units, unlike existing units, will have the option of locating closer to sources of low-sulfur coal, thereby reducing the transportation cost component of the premium.

Capacity and Energy Penalties. Capacity and energy penalties of 3 percent were attributed to both recirculating cooling systems and flue gas desulfurization systems. As these penalties are not reported by utilities in the Form 67 submittals, it was necessary to use other sources of information in the analysis. The cooling tower capacity penalty reflects a penalty of 2 percent from increased turbine back pressure and 1 percent from system operating requirements.[9] The capacity penalty for flue gas desulfurization systems is based on the mean of capacity penalties reported by PEDCo in its July-September 1980 EPA Utility FGD Survey.[10]

Capacity losses associated with capacity penalties for pollution control equipment are generally made up by sizing new units larger than they would otherwise be. In the cost analysis it was assumed that this replacement capacity would

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[9] This assumption is based on EPA, The Economic Analysis of Effluent Guidelines, Steam Electric Powerplants, 1974. As noted in Chapter II, the thermal portion of these guidelines was remanded in 1977 and has not been reinstituted. Consequently more recent technical or economic analyses of cooling towers have not been performed for EPA.

[10] PEDCo Environmental, Utility FGD Survey, July-September 1980. The standard deviation of the capacity penalties reported by PEDCo is 1.46 percent. Using a 1976 in-service date and a 60 percent capacity factor approximately 71 percent of the plants fall within this range and will have a capacity penalty within 1 mill per kWh of that calculated using a 3 percent capacity penalty.

be of the same fuel type as the unit on which the pollution control equipment was installed and would have the same in-service year. Plant construction costs for replacement capacity were based on other analyses performed for EPA and are shown in Table IV-18.

Table IV-18

PLANT CONSTRUCTION COSTS USED IN THE UNIT-CATEGORY ANALYSIS

(current $/kW)

In-Service Year	Type of Plant: Coal	Oil	Gas
1979	413	298	211
1978	389	280	199
1977	368	265	188
1976	341	254	174
1975	316	235	161
1974	270	201	138
1973	223	166	114
1972	210	156	107

Source: TBS estimates based on data provided by ICF, Inc.

In addition to this capacity penalty, an energy penalty reflects fuel and operating expenses to generate power needed to operate the equipment and to compensate for losses in efficiency. Fuel expenses were determined by adding a base cost of high-sulfur fuel and the individual unit's fuel premium. National average nonfuel operation and maintenance expenses were computed at 2.57 mills per kWh.

Costs Not Reported or Reflected in the Form 67s. Although the focus of this study is on federal environmental regulations, the only actual cost data available in the Form 67s reflect total pollution control costs. To the extent, therefore, that state or local requirements would exist in the absence of federal regulations or that utilities would undertake certain expenditures for other reasons, the costs identified in this analysis are not entirely attributable to federal regulations. Costs attributed to environmental compliance can be incurred as a result of federal, state, or local environmental regulations or of measures taken by a utility for economic reasons. In some cases, state air, water, and solid waste pollution control requirements exceed the minimum standards necessary for compliance with federal regulations. In other cases, pollution control equipment--for example cooling towers or TSP control systems--may have been installed in the absence of environmental regulations.

Only total pollution control costs are identified in the analysis and no attempt is made to differentiate federal and state requirements. Data reported in the Form 67s do not differentiate among costs incurred in complying with federal, state, and local regulations, nor do they indicate whether certain expenditures were undertaken for economic rather than environmental reasons. To attribute costs in this way would be difficult for individual plants to do, and the unit-level analysis presented no reasonable principle for doing so.

Costs for meeting chemical effluent limitations guidelines are not reported in the Form 67s. Plants coming into service before 1974 were assumed to retrofit equipment to meet the chemical guidelines in 1976 at a cost of $2.75 per kW (1976 dollars). Plants coming into service after 1974 were assumed to meet the BPT guidelines in their in-service year without a retrofit premium at an average cost of $2.28. These costs are based on costs developed for the 1974 effluent limitations guidelines. Operations and maintenance expenditures for both categories of plants were assumed to be $.97 per kW.[11]

Finally, the Form 67s do not capture combustion modifications instituted to meet NO_x limitations. Therefore, to the extent that such modifications have been undertaken, this analysis understates the costs of environmental regulation.

Generation-Related Costs. It was also assumed in the unit-level analysis that quantities related to generation--capacity factors, fuel consumption, and nonfuel operations and maintenance expenses--were as reported in the Form 67s. Actual 1979 fuel consumption and generation data were used because these data are consistent with reported pollution control operations and maintenance expenses. This approach meant, however, that anomalous influences on generation and fuel choices in 1979 (for example, weather patterns and oil shortages) were incorporated into the analysis.

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[11]EPA, The Economic Analysis of Effluent Guidelines, Steam Electric Powerplants, 1974. The 1973 data used in the 1974 economic analysis were updated to 1979 dollars using the GNP deflator.

The use of actual 1979 data may result in an understatement of generation and fuel consumption by oil-fired units. Two factors resulted in low oil-fired generation in 1979: rapidly increasing oil prices and excess coal-fired capacity. During 1979 the price paid by utilities for oil increased by 75 percent and the quantities of oil consumed decreased by 15 percent.[12] That year it was more economical for eastern utilities to purchase power from the Midwest than to generate their own power using high-cost oil. This alternative only exists for oil-fired units so long as excess coal capacity is available in the Midwest. Therefore, as growth in demand diminishes excess coal capacity in the Midwest, oil-fired generation in the East will increase despite the high cost of oil.

The analysis also does not capture the effects of environmental regulations that are manifested in changes in dispatch patterns rather than in increased costs of generating electricity. Some plants are utilized less intensively because they are required to burn expensive low-sulfur fuels, and others are dispatched on an environmental basis. The decline in the economic value of these plants that results from pollution controls is attributable to environmental regulations. In the analysis of unit-level compliance costs, however, a cost for pollution control is only attributed to plants that burn low-sulfur fuels and not to plants that are idle because of the high cost of low-sulfur fuel.

Finally, it is difficult to establish an approach that correctly captures environmentally related costs of fuel choice decisions in constructing, converting, or reconverting electric utility generating units. Many studies have adopted a subjective approach to the attribution of costs that overlooks the real economic pressures for originally building oil-fired units, for converting coal units to oil, or for not reconverting to coal. On the other hand, the EPA approach used in this study certainly fails to capture all the costs associated with environmental compliance. Refer to pages IV-43 through VI-50 for a more detailed discussion of the reasons for fuel choices and the determination of environmental costs.

<u>Compliance Status</u>. Inherent in the unit-category pollution control analysis is the assumption that existing units are in compliance with applicable emission standards or are moving toward compliance using approved strategies and schedules as reported by utilities in their Form 67 submittals. An

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[12]<u>Cost and Quality of Fuels--1979</u>, p. 14.

additional assumption is that state air pollution control agencies enforce emission standards with equivalent levels of enforcement activities across states and regions.

Although the second assumption is difficult to test, compliance status can be examined by comparing a unit's allowable emissions with reported or calculated emissions. Based on data provided by EPA, the ratio of annual calculated emissions to annual allowable emissions was reviewed for all fossil-fuel units that submitted 1979 Form 67s.[13] The arithmetic mean of the ratios (0.82) was interpreted by ICF and EPA to mean that, on average, units were in compliance with SIP limitations and had allowed a small margin of safety for unpredictable variations in fuel quality or in equipment efficiency.

A closer examination, however, reveals significant deviations from the mean. Those units with SO_2 ratios less than 0.8 generally reported higher actual emissions in their Form 67 submittals than were calculated by applying the standard formulas.[14] Units with ratios that exceeded 1.0--implying that they were out of compliance--fit into one of several possible categories. Many units reported lower annual emissions than were calculated. Other units were moving along state-approved compliance schedules and had not achieved compliance by the end of the year.

In other cases the 1979 fuel data are not consistent with emission standards; some units had achieved compliance by decreasing their fuel's sulfur content by year-end, even though the average fuel quality reported for the entire year implied noncompliance. For this reason, the analysis may understate fuel premiums. Temporary exemptions or litigation proceedings were a further reason for calculated emissions in excess of allowable emissions. However, fewer than 4 percent and 1 percent, respectively, of the units in the Energy Database are not proceeding toward compliance with SO_2 and TSP standards, and these units do not substantially affect the results of the analysis.

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[13] ICF, Inc., Survey of Utility Power Plant Emissions and Fuel Data; and Review of Calculated and Allowable Emissions for Existing Utility Steam Power Plants, prepared for EPA, October 1980.

[14] EPA, Compilation of Air Pollutant Emission Factors, August 1977.

Baseline Assumptions

Pretax revenue requirements in the absence of pollution controls were developed for each unit category to provide a

basis of comparison for pollution control costs. These costs were based on average characteristics for units in each category developed from the Energy Database (Table IV-19) and on unit-level capital and operating costs.

Table IV-19

UNIT CHARACTERISTICS USED IN DEVELOPING BASELINE COSTS OF GENERATING ELECTRICITY

In-Service Year	Fuel Type: Coal	Oil	Gas	Gas/Oil
	Average In-Service Year			
Pre-1972	1961	1962	1963	1963
1972-1976	1973	1974	1974	1974
1977-1979	1978	1978	1977	1977
	Average Nameplate Capacity (MW)			
Pre-1972	168	92	119	133
1972-1976	498	447	308	326
1977-1979	411	559	290	259
	Average Heat Rate (Btu/kWh)			
Pre-1972	10,380	10,549	10,739	10,774
1972-1976	10,324	9,771	9,617	10,602
1977-1979	10,856	11,072	10,282	10,524
Average	10,520	10,464	10,213	10,633
	Average Capacity Factors (percent)			
Pre-1972	56.8	36.9	54.5	49.7
1972-1976	62.9	46.3	61.3	45.7
1977-1979	52.2	33.8	20.2	44.8
Average	57.3	39.0	45.3	46.7

Source: Energy Database.

Costs considered in developing revenue requirements included:

- Capital-related charges on the units' undepreciated value. These were annualized on a pretax basis using the capital recovery method. This calculation assumed a total plant life of 30 years, an embedded cost of capital of 18.32 percent, and the same unit in-service dates shown in Table IV-19. These charges were then added to annual fuel, operations and maintenance, and indirect expenses, along with state and local taxes.

- Fuel expenses. Annual fuel expenses were based on heat rates reported in the Energy Database and average 1979 fuel costs. Heat rates used in developing baseline costs are the average heat rates for each unit-category shown in Table IV-19. Fuel costs are the 1979 averages reported by DOE in the <u>Cost and Quality of Fuels</u>. Because a pollution control premium was attributed to the use of low-sulfur fuels, the fuel cost used in developing baseline costs was that for high-sulfur fuel.

- Nonfuel direct operations and maintenance expenses; indirect expenses (transmission, distribution, and administration expenses); and taxes other than income tax. These remaining annual expenses were based on industry averages reported by DOE in the 1979 <u>Statistics of Privately Owned Utilities</u>. In 1979, the average nonfuel operating expenses for the industry were 2.57 mills per kWh, average indirect expenses were 5 mills per kWh, and average taxes other than income taxes amounted to 2.9 percent of undepreciated plant value.

The resulting baseline costs of generating electricity as shown in Table IV-20 provide a reference point for pollution control costs that will be described in the next section of this chapter.

Table IV-20

BASELINE COSTS OF GENERATING ELECTRICITY AT MODEL UNITS SELECTED FOR ANALYSIS

(1979 mills/kWh)

In-Service Year	Fuel Type: Coal	Oil	Gas	Gas/Oil	Average All Fuels[1]
Pre-1972	22.4	32.9	28.1	30.1	25.4
1972-1976	24.9	37.3	29.2	32.6	27.9
1977-1984	34.9	50.2	38.0	43.1	38.1
Average all years[1]	24.2	37.4	28.5	31.3	27.2

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]Averages are across fuel types or in-service years weighted by generation.

Source: Energy Database and TBS calculations.

Results of the Unit-Level Analysis

This section discusses the results of the analysis of pollution control costs at the unit level. It begins with a discussion of the distribution of compliance costs among coal, oil, gas, and gas/oil units. Then it examines the components of pollution control costs by types of costs (capital, operations, and maintenance) and by pollutants controlled. The discussion finally turns to an analysis of the costs incurred by individual unit categories and to an examination of the reasons for variations in costs within unit categories.

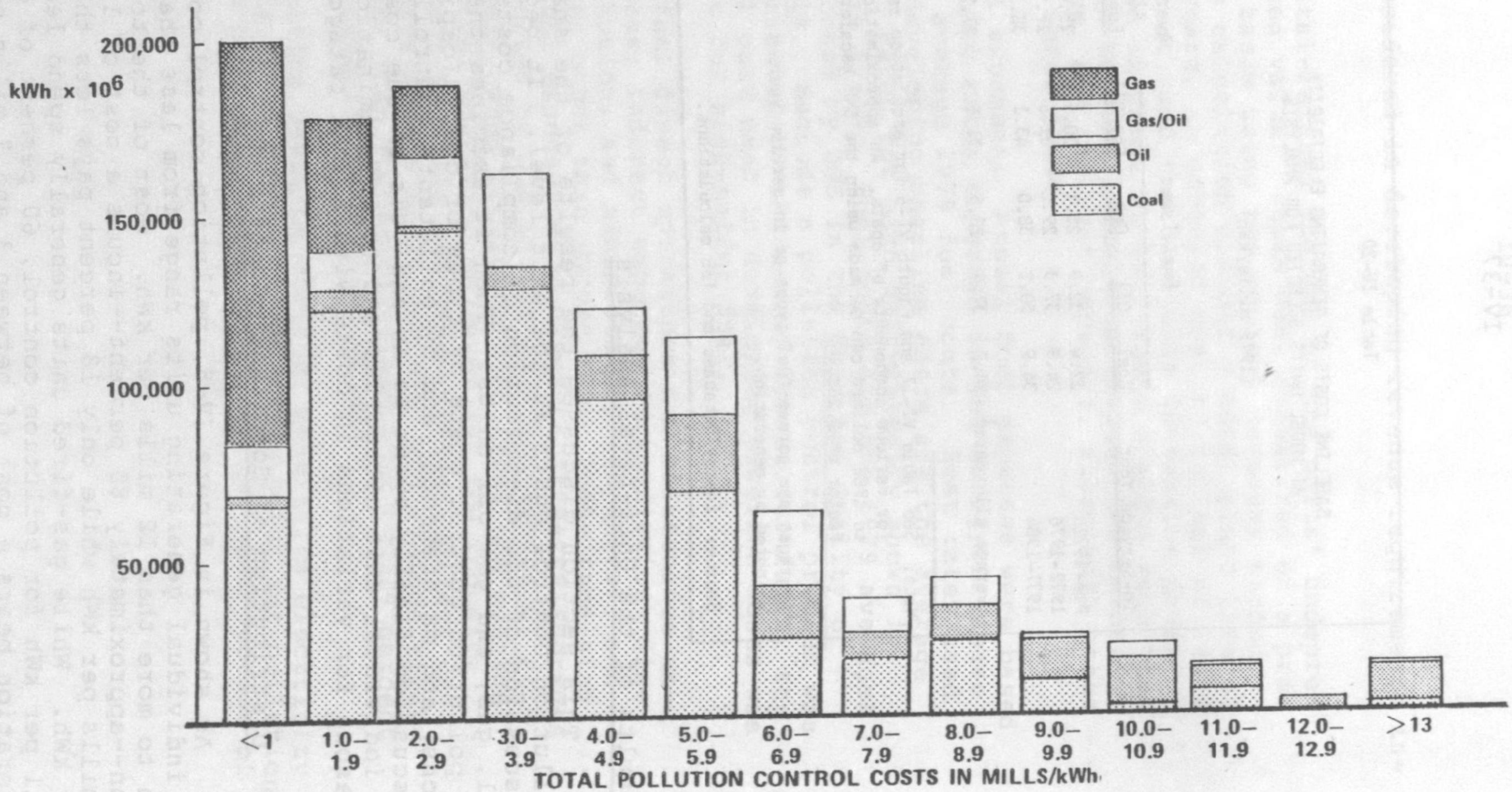
Distribution of Compliance Costs

As shown in Figure IV-5, pollution control costs incurred by individual generating units range from less than 1 mill per kWh to more than 12 mills per kWh. Most of the total generation--approximately 85 percent--incurs a cost of less than 6 mills per kWh while only 18 percent pays less than 1 mill per kWh. While gas-fired units generally spend less than 1 mill per kWh for pollution control, 60 percent of oil-fired generation bears a cost of between 3 and 7 mills per kWh and

Figure IV–5

DISTRIBUTION OF FOSSIL-FIRED STEAM-ELECTRIC GENERATION AS A FUNCTION OF POLLUTION CONTROL COSTS AND FUEL TYPE

1979 DOLLARS



Source: Energy Database.

only 12 percent spends less than 3 mills per kWh. Gas/oil units have similar characteristics to gas or oil units, depending on which fuel they consume preponderantly.

Coal-fired units account for the preponderant share of total generation and also display the greatest spread in pollution control costs. Seventy-five percent of coal generation incurs pollution control costs of less than 5 mills per kWh. The remaining coal generation is spread among units that spend up to 13 mills per kWh for pollution control. As will be discussed below, the reasons for the spread in coal-fired unit pollution control costs concern differences in pollution control standards and compliance strategies as well as differences in the availability of low-sulfur coal.

Components of Compliance Costs

Control of SO_2 is the dominant contributor to average national pollution control costs (Table IV-21). Out of a national average cost of pollution control for all fossil-fuel types and age categories of 3.88 mills per kWh, SO_2 control accounts for 2.72 mills per kWh or 70 percent of the total. The remaining 30 percent is distributed relatively evenly among controls for TSP and water pollution with solid waste disposal included in SO_2 and TSP control.

SO_2 control costs consist primarily of a premium paid by coal- and oil-fired units for low-sulfur fuels. Less than one-tenth of the national cost of SO_2 control as of 1979 was attributable to the use of scrubbers. Although scrubbers are costly on a unit basis, they are less prevalent than other pollution control systems. For this reason, they contribute only 6 percent to the average cost of pollution control, as compared, for example, to 11 percent for TSP control. As will be noted in subsequent chapters, however, the contribution of scrubbers to national costs will increase substantially in the future.

All units incur some costs to meet water pollution chemical guidelines and about 20 percent of the capacity incurs costs for control of thermal discharges. Thermal pollution control costs are attributed only to units that have installed cooling towers or ponds since 1972 because earlier units would not have installed thermal discharge controls in response to environmental regulations. The cost of meeting chemical guidelines is approximately 0.44 mills per kWh and does not vary significantly among unit categories. Although this cost is slightly lower than the cost of meeting chemical guidelines

Table IV-21

AVERAGE ANNUALIZED COSTS OF COMPLIANCE BY POLLUTANT

(1979 mills/kWh)

Fuel Type and In-Service Year	SO_2 Control FGD[1]	SO_2 Control Fuel	TSP Control[1]	Thermal	Chemical	Total
Coal						
Pre-1972	0.16	1.96	0.75	0.05	0.51	3.42
1972-1976	0.34	1.53	0.40	0.86	0.35	3.47
Post-1976	1.92	1.71	0.76	1.02	0.42	5.81
Average Coal	0.38	1.82	0.67	0.34	0.46	3.67
Oil						
Pre-1972	0	7.18	0.10	<0.01	0.64	7.93
1972-1976	0	6.20	0.18	0.29	0.44	7.17
Post-1976	0	8.03	0.09	1.45	0.45	10.03
Average Oil	0	6.86	0.14	0.37	0.53	7.89
Gas						
Pre-1972	0	0.07	<0.01	0.05	0.28	0.40
1972-1976	0	0.11	<0.01	0.49	0.24	0.85
Post-1976[2]	0	0.04	0.69	1.66	0.47	2.86
Average Gas	0	0.08	<0.01	0.19	0.27	0.55
Gas/Oil						
Pre-1972	0	4.47	<0.01	0.03	0.43	4.94
1972-1976	0	2.27	0	0.57	0.33	3.17
Post-1976	0	1.93	0	1.67	0.32	3.84
Average Gas/Oil	0	4.19	0	0.10	0.42	4.72
National Average	0.24	2.48	0.43	0.30	0.44	3.88

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]Includes solid waste disposal.
[2]Costs for post-1976 gas units are distorted by a very limited number of observations.

Source: Energy Database and TBS calculations.

on an average basis, it is significantly higher on a unit basis for those units that are required to install cooling towers or ponds.

The premium paid by utilities for low-sulfur fuels is the largest component of compliance costs (Table IV-22). This premium accounts for 64 percent of pollution control costs and

Table IV-22

AVERAGE ANNUALIZED COSTS OF COMPLIANCE BY COST COMPONENT—TOTAL AIR, WATER, AND SOLID WASTE

(1979 mills/kWh)

Fuel Type and In-Service Year	Capital Cost	O&M	Energy Penalty	Fuel Premium	Total	Total as Percent Increase Over Baseline[2]
Coal						
Pre-1972	0.76	0.69	0.02	1.96	3.42	15
1972-1976	0.97	0.51	0.46	1.56	3.47	14
Post-1976	2.81	0.71	0.57	1.72	5.81	17
Average Coal	1.02	0.64	0.18	1.82	3.67	15
Oil						
Pre-1972	0.27	0.48	0	7.18	7.93	24
1972-1976	0.44	0.33	0.20	6.20	7.17	19
Post-1976	0.99	0.30	0.71	8.03	10.03	21
Average Oil	0.45	0.39	0.19	6.86	7.89	21
Gas						
Pre-1972	0.05	0.26	0.02	0.07	0.40	2
1972-1976	0.14	0.22	0.38	0.11	0.85	3
Post-1976[1]	2.12	0.35	0.36	0.04	2.86	8
Average Gas	0.10	0.25	0.12	0.08	0.55	2
Gas/Oil						
Pre-1972	0.10	0.36	<0.01	4.47	4.94	16
1972-1976	0.42	0.27	0.21	2.27	3.17	10
Post-1976	0.80	0.37	0.76	1.92	3.84	9
Average Gas/Oil	0.14	0.35	0.03	4.19	4.72	15
National Average	0.72	0.53	0.15	2.48	3.88	14

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]Costs for post-1976 gas units are distorted by a very limited number of observations.

[2]Baseline costs are shown in Table IV-21.

Source: Energy Database and TBS calculations.

it is more than three times as large as capital costs (19 percent) associated with pollution control equipment.

Capital costs are incurred primarily by coal-fired plants that have TSP control systems and in some cases scrubbers as well. Chemical and thermal pollution controls present at all types of steam units also have capital cost components. Capital costs for chemical controls are lower on a unit basis than for TSP and SO_2 control but are distributed over a greater number of systems.

Energy penalties of 3 percent of total generation are associated with the use of both scrubbers and cooling towers. These penalties contribute approximately 4 percent to pollution control costs.

Variations in Compliance Costs Among Unit Categories

Pollution control costs vary as a function of both unit age and fuel type. The national cost of pollution control described above is a weighted average of costs for coal, oil, gas, and gas/oil units in three separate age categories. The distribution of these costs by fuel type and unit age will be discussed below.

Distribution of Costs by Fuel Type. The average cost of pollution control for oil-fired units is two times as high as for coal-fired units and more than ten times as high as it is for gas-fired units. This is because a premium for low-sulfur oil accounts for 6.86 mills per kWh or 87 percent of total pollution control expenditures by oil-fired units as shown in Table IV-22. Similarly, gas/oil units incur a premium to the extent that they consume low-sulfur oil. This premium accounts for nearly 90 percent of pollution control expenditures by gas/oil units and results in high pollution-control costs for units. Particulate, thermal, and chemical control costs for oil and gas/oil units are generally lower than those for coal-fired units, but these costs are dwarfed by the low-sulfur oil premium.

As noted above, the assumptions used in developing the low-sulfur oil premium may overstate it. To determine the sensitivity of the results of the analysis, two alternative assumptions were tested: (1) using the cost of 2.5 rather than 3 percent sulfur oil as the base cost that utilities would pay for oil in the absence of environmental regulations and (2) basing the oil premium on the cost of desulfurization of high-sulfur oil. For units burning 1 percent sulfur oil, the low-sulfur oil premium would be 33 percent lower in the first case and in the second it would be 11 to 36 percent lower depending on the cost of desulfurization and the Btu content of the oil. Although these differences are substantial, they do not alter the basic conclusions of this analysis that the low-sulfur oil premium paid by oil-fired units dominates all other environmental expenditures and that oil units spend more than other categories of units for pollution control. For the 60 percent of oil-fired capacity that burns oil with less than 1 percent sulfur, moreover, the percent decrease in the fuel premium would be lower than that noted above.

Control of SO_2 also accounts for the dominant share (60 percent) of the cost of pollution control for coal units. Eighty-three percent of the cost of SO_2 control among coal units is a premium paid by utilities for low-sulfur coal. As in the case of low-sulfur oil this premium could be overstated because of the assumption that the price eastern utilities would pay for coal in the absence of environmental regulations is the price of coal with more than 3 percent sulfur. If the base price of coal were increased, instead, to the average price of 2.5 percent sulfur coal, the premium paid by eastern utilities would be approximately 37 percent lower. The average fuel premium incurred by coal-fired units nationally would be approximately 26 percent lower. Again, this result would not alter the basic conclusion that the low-sulfur coal premium dominates other pollution expenditures for coal-fired units.

Only coal and oil-fired units spend appreciable amounts for TSP control. Because all coal units have TSP control systems, coal units as a whole spend nearly two times as much on TSP control systems as they do on scrubbers (although for individual plants that have scrubbers the cost for scrubbers is much higher than that of TSP controls). Oil-fired units spend one-fifth as much as do coal-fired units for TSP control per kWh of generation. This expenditure by oil units amounts to 2 percent of their total pollution control expenditures.[15] TSP control for gas and gas/oil units amounts to less than 0.01 mills per kWh.

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[15] It should be noted that the use of low-sulfur oil also results in a reduction in TSP loadings. Since a plant would not ordinarily incur a low-sulfur oil premium solely for TSP control, however, the full cost of burning low-sulfur oil has been attributed to SO_2 control. Among gas and gas/oil units the cost of TSP control is insignificant.

Total costs for controlling water pollution are evenly distributed among fuel types. In the case of gas units, however, water pollution accounts for nearly 85 percent of total pollution control costs because overall costs for these units are lower. Chemical control costs are the same for coal and oil plants and only slightly lower for gas plants. Thermal costs remain relatively constant across fuel types because they depend more on a plant's location near a source of plentiful cooling water rather than on its fuel type.

Although total pollution control expenditures for coal-fired units are less than one-half those for oil-fired units, their capital costs associated with pollution control equipment are two and one-quarter times as great as they are for oil units and ten times as great as they are for gas units. Coal units incur capital costs primarily from using TSP control devices and SO_2 scrubbers. Since very few oil and gas plants have extensive TSP control systems and none has scrubbers, capital costs for oil and gas units are significantly lower. The remaining capital costs for thermal and chemical control are approximately equal for coal and oil plants and only slightly lower for gas-fired plants.

The use of TSP control systems and scrubbers at coal plants also results in higher operation and maintenance expenses and energy penalties. Particulate control systems and scrubbers have operational expenses associated with ash and sludge disposal as well as system operation and maintenance expenses. In addition, wet scrubbers incur an energy penalty of approximately 3 percent of total unit generation. Oil and gas units, by contrast, incur only the operation and maintenance expenses associated with the use of thermal and chemical pollution control devices.

Distribution of Costs by Unit Age. Legislation governing air, water, and solid waste pollution was passed in the early and mid-1970s. Thus, plants that came into service before 1972 incur capital expenditures attributable to the Clean Air, Clean Water, and Resource Conservation and Recovery Acts only to the extent that they have retrofitted pollution control equipment. Units that have come into service since the mid-1970s have been subjected to the more extensive new source requirements of the Clean Air and Clean Water Acts.

Expenditures by older units for pollution control can in some cases be disproportionately high. One reason for higher costs incurred by older units is that these tend to be located in more heavily industrialized and populated areas where relatively stringent pollution control measures have frequently been required to attain compliance with the national ambient air quality standards. In meeting these standards units have had to retrofit pollution control equipment at a cost that can be significantly higher than that of installing equipment in a new plant, or they have had to burn cleaner fuels to compensate for their location in heavily populated areas. Some older oil and gas/oil units that are used only occasionally also have high heat rates, and incur a higher fuel premium because they consume more fuel per kilowatt-hour of generation.

Oil-fired units that have come into service after 1976 have the highest pollution control costs of any category of units. As a rule, these units are subject to the NSPS for air promulgated in 1972 but applying to plants commencing construction after August 1971. To meet the 0.8 pound per million Btu, these units burn very low-sulfur oil.

The major age-related variations in pollution control costs occur among coal-fired units. These variations result from changes in environmental standards and pollution control strategies as well as from differences in equipment costs. Pollution control costs for coal-fired units are about the same for pre-1972 and 1972-1976 units but increase by 67 percent for units coming into service after 1976. This increase is attributable to an increase of 1.76 mills per kWh for SO_2 control due primarily to scrubber systems (1.58 mills per kWh) but also to increasing use of lower sulfur fuels. Plants coming into service after 1977, it should be noted, are generally subject to the 1972 NSPS air emission limit of 1.2 pounds of SO_2 per million Btu.

Capital costs for pollution control triple for post-1976 coal units as compared to earlier units. Both the increasing use and cost of scrubbers affect this increase in capital costs for coal-fired plants. The use of scrubbers, for example, has become more prevalent on newer units, increasing from only 4 percent of the pre-1977 capacity to 36 percent of the post-1976 capacity.

Despite the virtual absence of cooling towers and the limited use of scrubbers on pre-1972 coal units, the contribution of capital costs to total pollution control costs is relatively large for pre-1972 units, as compared to 1972-1976 units. This difference reflects retrofit premiums incurred for TSP, SO_2, and chemical pollution controls required by regulations under the Clean Air and Clean Water Acts.

Variations in Compliance Costs
Within Unit Categories

The main reason costs vary within an individual unit category is SO_2 control. Costs for thermal and chemical controls are approximately the same for high- and low-cost units in the same categories. Particulate control costs are higher for high-cost coal units, but contribute less to total costs than do SO_2 control costs for these units.

The fuel premium for oil-fired units exhibits much the same variation as do total pollution control costs, indicating that the variation in costs within oil-unit categories can be attributed to SO_2 control. Two factors affect SO_2 control costs within oil-fired unit categories--the sulfur content of the oil burned and the plant's heat rate. Generally, the fuel/sulfur content dominates SO_2 control costs. For example, units with less than 1.5 percent sulfur fuel have fuel premiums of less than 5 mills per kWh and units with less than 1 percent sulfur oil have fuel premiums greater than 7 mills per kWh. Some anomalies in this pattern arise in the case of older, low-capacity factor, high heat-rate units that consume more fuel per kWh of electricity generated. For example, the 54 oil-fired units that incur a fuel premium of more than 12 mills per kWh operate at an average capacity factor of 14 percent. Of these 54 units, 45 came into service prior to 1950.

Control costs for SO_2 also account for the major variations within categories of coal units. Among units in service before 1972, the highest costs are incurred by units with SO_2 scrubbers. Thirteen of the 16 pre-1972 units with costs higher than 10 mills per kWh have FGD systems. These units also have fuel premiums and TSP control costs that are two times as high as the average for pre-1972 coal units. In contrast, pre-1972 units with slightly lower costs of 7 to 10 mills per kWh have fuel premiums and TSP control expenses equivalent to those for higher-cost units, but only one of these units has a scrubber.

Among 1972-1976 and post-1976 units, there is a greater intermixing of control strategies than among pre-1972 units. Scrubbers account for 62 percent of the total cost of pollution control for 1972-1976 coal units with pollution control costs greater than 7 mills per kWh, while for 1972-1976 coal units as a whole, scrubbers account for only 33 percent of pollution control costs. These higher cost units, however, incur a lower fuel premium than the category average, indicating the use of scrubbers rather than low-sulfur coal to meet SO_2 standards. High-cost units that have come into service since 1976 have scrubber costs that are twice the category average and fuel premiums that are 30 percent higher. This indicates that both low-sulfur fuels and scrubbers are used to comply with SO_2 limits. Costs for controlling TSP among these units are also 68 percent higher than the category average.

Low-cost units also exhibit distinct characteristics. Eighteen percent of pre-1972 coal units burn high-sulfur coal and do not have scrubbers. These units incur dramatically lower pollution control costs than do units that either burn low-sulfur coal or have scrubbers. Low-cost units that have come into service after 1972, by contrast, tend to be located in the western states and have readily available supplies of low-sulfur coal.

FUTURE UNIT-LEVEL COMPLIANCE STRATEGIES AND COSTS

The results of the unit-level analysis thus far reflect costs incurred by units under regulations in effect in 1979. Future plants and plants being reconverted from oil to coal will incur certain additional expenditures resulting from more stringent regulations that will affect units coming into service after 1980. In this section these costs, which form the basis for the national-level analysis presented in Chapter VI, will be examined at the individual unit level.

Compliance Strategies

Units coming into service after 1980 will be built mostly in PSD areas that meet the national ambient air quality standards and will meet BACT standards. Definitions of BACT, however, will vary as a function of unit-specific factors. Regulations applying to PSD areas specify that BACT will not be less stringent than applicable NSPS requirements--usually NSPS I for pre-1985 units and NSPS II for most post-1984 units. Beyond NSPS requirements, some units, generally those sited in the vicinity of Class I PSD areas or areas where available increments are nearly exhausted, may be required to install BACT pollution control technologies that exceed NSPS I requirements.

Compliance strategies by future units will vary depending on whether a unit is meeting BACT incorporating NSPS I, NSPS II, or more stringent requirements. Since highly efficient TSP control systems are increasingly being used, major differences will concern SO_2 control strategies.

Information concerning future units compiled in the Energy Database indicates that 48 percent of units coming into service in the 1980-1984 period will meet NSPS II standards. Among these units, those locating in the East will tend to install high-efficiency scrubbers and those locating in the West will burn low-sulfur fuels with lower efficiency scrubbers. Ninety percent of the NSPS II capacity coming into service in the East between 1980 and 1984 will burn high-sulfur coal. This capacity will meet a standard of 1.2 pounds of SO_2 per million Btu by installing high-efficiency scrubbers with 90 percent or greater removal efficiencies. Only 10 percent of the eastern capacity will meet a standard of 0.6 pound of SO_2 per million Btu by burning lower sulfur coal and installing less efficient scrubbers. Eighty percent of capacity locating in the West, by contrast, will burn low-sulfur coal and meet the 0.6 pound standard by installing scrubbers with 70-80 percent removal efficiencies. The remaining 20 percent of western capacity is located in areas where BACT standards exceed the minimum requirements of NSPS II. These units will burn low-sulfur coal and install scrubbers whose removal efficiencies are 90 percent or greater.

Compliance Costs

Costs of compliance with alternative regulatory scenarios shown in Table IV-23 are significantly different for units burning eastern and western coals. These costs are primarily based on engineering estimates provided by EPA and not on costs listed in the Energy Database. Western units are assumed not to require scrubbing to meet NSPS I standards, although in practice BACT standards applying to western units have in some cases required scrubbers. Eastern units burning low-sulfur coals also do not require scrubbers; however, these units incur a fuel premium of 4 mills per kWh for 0.8 percent sulfur coal (1.2 pounds per million Btu). Eastern units burning high-sulfur coal are assumed to meet NSPS I standards by burning coal containing 2.4 percent sulfur and installing wet scrubbers with 70 percent removal efficiencies. Both western and eastern low-sulfur coal units comply with NSPS II limits by installing scrubbers with 70 percent removal efficiencies--wet scrubbers in the case of eastern units and dry scrubbers in the case of western units. Eastern high-sulfur coal units comply with NSPS II by installing wet scrubbers with 90 percent removal efficiencies. Finally, it is assumed that both western and eastern low sulfur coal units will install wet scrubbers with 90 percent removal efficiencies to meet more stringent BACT standards that may apply on a case-by-case basis.

Table IV-23

FUTURE COSTS OF COMPLIANCE WITH ALTERNATIVE REGULATIONS FOR A 500-MW COAL PLANT

(1979 dollars)

Standards	NSPS I	NSPS II	More Stringent BACT
SO_2			
Western Coal			
FGD Capital ($/kW)	-	69.01	95.60
Waste Disposal Capital ($/kW)	-	3.67	20.00
Operation and Maintenance (mills/kWh)[1]	-	1.24	1.47
Energy Penalty (percent)[1]	-	1.43	3.43
Capacity Penalty (percent)[1]	-	0.59	1.53
Eastern Coal[2]			
FGD Capital ($/kW)	0/69.01	69.01/104.7	104.7
Waste Disposal Capital ($/kW)	0/3.67	3.67/46.00	46.00
Operation and Maintenance (mills/kWh)[1]	0/1.24	1.24/1.71	1.71
Energy Penalty (percent)	0/1.43	1.43/3.57	3.57
Capacity Penalty (percent)[1]	0/0.59	0.59/2.21	2.21
Fuel Premium (mills/kWh)[1]	4/0	4/0	2.38
TSP			
Western Coal			
Capital ($/kW)	56.34	56.34	61.03
Operation and Maintenance (mills/kWh)	0.56	0.56	0.28
Energy Penalty (percent)	0.95	0.95	0.21
Capacity Penalty (percent)	0.95	0.95	0.21
Eastern Coal[2]			
Capital ($/kW)	35.36	56.34/35.36	35.36
Operation and Maintenance	0.16	0.56/0.16	0.16
Energy Penalty (percent)	0.21	0.95/0.21	0.21
Capacity Penalty (percent)	0.21	0.95/0.21	0.21
Thermal Standards			
Capital	11.20	11.20	11.20
Operation and Maintenance (mills/kWh)	0.23	0.23	0.23
Energy Penalty (percent)	0.65	0.65	0.65
Capacity Penalty (percent)	1.65	1.65	1.65
Chemical Standard			
Capital	6.16	6.16	6.16
Operation and Maintenance	0.07	0.07	0.07
Energy and Capacity Penalty	0.0	0.0	0.0

Note: Energy penalty is expressed as percent of generation; capacity penalty is expressed as percent of capacity. See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]Includes solid waste disposal costs for O&M and capacity and energy penalties.

[2]Costs presented as low-sulfur coal/high-sulfur coal. This analysis assumes that 10 percent of eastern capacity uses dry scrubbing of low-sulfur coal.

Source: EPA (NSPS II engineering cost estimates); Energy Data-base (Thermal Standards and NSPS I FGD costs); and EEI (Chemical Standards).

Costs for meeting TSP, chemical, and thermal standards do not vary across regulatory scenarios. In all cases western units are assumed by EPA to install baghouses for TSP control; eastern units install high-efficiency electrostatic precipitators. Costs of meeting chemical standards are those required to meet 1974 BPT regulations that are currently in effect for the industry.[16] In the analysis of unit costs, all units are assumed to install cooling towers for thermal discharge control, although thermal controls may not be required in all cases.

Particulate and SO_2 standards add 3.6 to 14.6 mills per kWh to pollution control costs under alternative regulatory scenarios. As shown in Table IV-24 compliance with NSPS I limits is approximately 1.0 mills per kWh less costly for low-sulfur coal eastern units than it is for high-sulfur coal units. Although in specific instances advantageous coal purchasing arrangements may make scrubbers more attractive, this result is generally consistent with the results of both the case study portion of this report and with the analysis of compliance strategies based on the Energy Database presented earlier in this chapter. Utilities contacted in the case studies indicated that where possible they prefer a low-sulfur strategy on the basis of costs. The analysis of costs compiled in the database indicated that eastern low-sulfur coal units subject to NSPS I have costs that are 3 to 4 mills per kWh lower than do high-sulfur coal units that are required to install scrubbers to meet NSPS I. A full discussion of issues relevant to future coal prices and quality appears in Appendix D.

Given current scrubber technologies, costs of compliance with NSPS II limits will be somewhat lower for eastern high-sulfur coal units than for eastern low-sulfur coal units. The difference in cost between wet scrubbers with 90 percent and 70 percent removal efficiencies fails to compensate for the higher fuel premium incurred by low-sulfur coal units. The comparative advantage of a high-sulfur coal 90 percent removal strategy is reflected in the fact that 90 percent of 1980-1984 eastern units that meet NSPS II listed in the Energy Database will select this strategy. Successful introduction of a less costly dry scrubbing technology capable of 70 percent removal

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[16] The Agency is currently reconsidering chemical NSPS guidelines; however, considerable uncertainty concerning these guidelines continues.

Table IV-24

TOTAL UNIT-LEVEL COSTS PER KWH
UNDER ALTERNATIVE FUTURE REGULATIONS

(1979 mills per kWh)

	NSPS I									
	Baseline		Air Only (1985)		NSPS I (1985)		NSPS II (1990)		BACT (1990)	
Coal Type	1985	1990	Total	Percent of Baseline	Total	Percent of Baseline	Total	Percent of Baseline	Total	Percent of Baseline
Eastern Low-Sulfur	61.6	60.9	6.2	10	7.6	12	13.4	22	14.6	24
Eastern High-Sulfur	61.6	60.9	6.9	11	8.6	14	12.3	20	N/A	N/A
Western Low-Sulfur	57.5	56.3	3.6	6	5.3	9	9.4	17	11.5	20

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

N/A = Not applicable.

Source: EPA; TBS calculations.

efficiencies on eastern low-sulfur coal could, however, shift the comparative advantage to low-sulfur coal.[17]

For the purpose of this analysis, EPA projected that western units will meet NSPS II limits by burning low-sulfur coal and installing dry scrubbers with 70 percent removal efficiencies. Two factors contribute to the low cost incurred by western units: the ready availability of low-sulfur coal and the applicability of dry scrubbing technologies to western coal.

Costs under more stringent BACT standards involve 90 percent wet scrubbing on low-sulfur coal for both western and eastern units. These standards are not expected to be generally applicable, but for affected units more stringent BACT

[17] The base pollution control scenario in the national analysis incorporates the assumption that the use of dry scrubbing technologies in the East will not become widespread in the near term.

standards would raise pollution control costs by 11.5 to 14.6 mills per kWh or more than 20 percent of baseline costs. Information compiled in the Energy Database concerning 1980-1984 units that meet or exceed NSPS II standards indicates that none of these units located in the East will meet BACT standards that are more stringent than NSPS II, but that 20 percent of these units locating in the West will meet BACT limits that are more stringent than NSPS II.

COST-EFFECTIVENESS ANALYSIS

TBS also calculated quantities of SO_2 and TSP removed and the cost-effectiveness of removals for units in the Energy Database and for future units. The figures given in this section concerning quantities of pollutants removed and the costs of removing those pollutants give a rough approximation of the cost-effectiveness of pollution control costs. They do not address the more complex issue of benefits associated with these costs. An analysis of the latter issue would require an examination of where emissions take place and what populations are affected. It may be, for example, that the higher costs of pollution control at oil units are justified given the location of these units in urban areas. The analysis does indicate that with a shift from oil to coal units, the cost-effectiveness of environmental regulations will increase dramatically, particularly for TSP control. It does not indicate whether environmental quality will benefit or deteriorate as a result of this shift.

Existing Units

Uncontrolled unit-level emissions of both SO_2 and TSP were calculated assuming that no pollution control equipment existed and that coal units in the East would burn 3 percent sulfur coal and all oil units would burn 3 percent sulfur oil in the absence of environmental regulations. To determine quantities of pollutants removed, calculated unit-level emissions based on actual sulfur and ash contents and pollution control equipment in place were subtracted from uncontrolled unit emissions. Calculations of emissions were based on methodologies developed by EPA.[18]

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[18] U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42 Part A, Third Edition, August 1977.

Both fuel and equipment pollution control strategies were evaluated on the basis of the cost of removing one ton of pollutant. Most coal units burn coal exclusively or only a very small proportion of oil. Consequently, for coal units, fuel-related SO_2 removals generally consist of emission reductions obtained by burning coal with less than 3 percent sulfur. Since SO_2 emissions are also reduced by using scrubbers, the cost-effectiveness of using scrubbers was also calculated. Particulate removal at coal units was attributed entirely to equipment on the assumption the ash content of coal for reducing TSP emissions is not a determining factor in coal purchases. Since all coal units have highly efficient TSP control systems, incremental removals from burning lower-ash-content coal are insufficient to affect coal purchases.

Although oil units burn low-sulfur oil primarily to reduce SO_2 emissions, this also decreases TSP emissions. Consequently, for oil and gas/oil units, reductions in TSP emissions were calculated as a function of both the sulfur content of the fuel and the efficiency of TSP collection devices. Since oil and oil/gas units do not have scrubbers, reductions in SO_2 emissions at these units depend solely on the fuel sulfur content.

Quantities of Pollutants Removed

Nationally, as shown in Table IV-25, in 1979 steam-electric pollution controls reduced SO_2 emissions by 12 million tons and TSP emissions by 45 million tons. These reductions in emissions represented approximately 42 percent of potential SO_2 emissions and 98 percent of potential TSP emissions.[19] Coal-fired units accounted for 85 percent of potential SO_2 emissions but for only 75 percent of the reductions in SO_2 emissions. Coal units also accounted for more than 99 percent of potential emissions and reductions in emissions of TSP. Oil and gas/oil units reduced SO_2 emissions by 70 percent to 3.2 million tons from total potential emissions of 4.6 million tons for both categories of units.

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[19] It should be noted that to the extent that utilities would install TSP control systems to protect plant equipment even in the absence of environmental regulations, the full extent of reductions in TSP emissions should not be attributed to environmental regulations. It has been suggested, for example, that utilities would install TSP control equipment with 80 percent removal efficiencies to protect preheaters. If this is the case, only about 20 percent of TSP removals can be attributed to environmental regulations, and the cost-effectiveness of TSP removal declines comensurately.

Table IV-25

TOTAL 1979 NATIONAL POTENTIAL AIR POLLUTANT
EMISSIONS AND REMOVALS
BY UNIT CATEGORY

(thousands of tons)

	SO_2			TSP		
Unit Category	Total Removed	Potential Emissions	Percent Removed	Total Removed	Potential Emissions	Percent Removed
Coal						
Pre-1972	6,106	16,961	36	29,958	30,569	98
1972-1976	1,882	5,535	34	11,231	11,460	98
Post-1976	1,027	1,902	54	3,586	3,622	99
Total Coal	9,015	24,398	37	44,775	45,651	98
Oil						
Pre-1972	776	1,078	72	58	67	86
1972-1976	706	1,197	59	65	77	84
Post-1976	320	421	76	20	26	76
Total Oil	1,783	2,695	68	143	170	84
Gas/Oil						
Pre-1972	1,258	1,700	74	89	108	82
1972-1976	160	254	63	11	19	59
Post-1976	a	a	a	a	a	a
Total Gas/Oil	1,418	1,954	73	100	127	79
National Total	12,217	29,047	42	45,018	45,948	98

a = Insufficient observations.

Source: Energy Database and TBS calculations.

As shown in Table IV-26 substantial differences exist among unit categories in quantities of pollutants removed. As a group, coal units reduced potential SO_2 emissions by 37 percent. More recent coal units, however, removed a significantly greater proportion than earlier units of potential SO_2 emissions (54 percent as opposed to 34 and 36 percent).

Two factors contribute to the higher percent of total emissions removed by recent coal units. First, potential

Table IV-26

AVERAGE UNIT-CATEGORY
POTENTIAL AIR POLLUTANT EMISSIONS AND REMOVALS

(tons per million kWh)

	SO_2						TSP				
	Removal Strategy						Removal Strategy				
Unit Category	Low-Sulfur Coal	Low-Sulfur Oil[1]	Scrubbers	Total	Potential Emissions	Percent Removed	Low-Sulfur Oil	Equipment	Total	Potential Emissions	Percent Removed
Coal											
Pre-1972	7.92	0.19	0.33	8.48	23.25	36	0.01	41.69	41.70	42.53	98
1972-1976	5.95	0.08	1.04	7.07	20.62	34	<0.01	42.22	42.22	42.95	98
Post-1976	4.22	0.10	4.96	9.28	17.03	54	0.01	40.40	40.40	40.81	99
Total Coal	6.65	0.14	1.35	8.14	21.93	37	<0.01	41.11	41.11	41.88	98
Oil											
Pre-1972	0	9.74	0	9.74	13.53	72	0.56	.18	0.74	0.86	86
1972-1976	0	8.20	0	8.20	13.92	59	0.52	.23	0.75	0.89	84
Post-1976	0	1.61	0	11.61	15.33	76	0.74	a	0.74	0.97	76
Total Oil	0	9.46	0	9.46	13.96	66	0.57	.17	0.74	0.88	84
Gas/Oil											
Pre-1972	0	5.76	0	5.76	7.81	74	0.37	0.04	0.41	0.50	82
1972-1976	0	5.20	0	5.20	8.32	63	0.33	0	0.33	0.56	59
Post-1976	0	a	0	a	a	a	a	a	a	a	a
Total Gas/Oil	0	5.70	0	5.70	7.87	72	0.36	0.03	0.39	0.51	79

a = Insufficient observations.
[1] Coal units that also burn oil can attain SO_2 reduction by burning both fuels.

Source: Energy Database and TBS calculations.

emissions are lower because a larger share of units are located in the West where their potential emissions are based on 1 percent rather than 3 percent sulfur coal because they would burn low-sulfur coal even in the absence of environmental regulations. This means that reductions in emissions at western units are a higher percent of potential emissions. Second, scrubbers are much more prevalent among post-1976 coal units. On average, reductions in SO_2 emissions attributed to scrubbers are nearly five times greater among post-1976 units than among 1972-1976 units. In turn SO_2 reductions due to scrubbers are more than three times greater among 1972-1976 units than among pre-1972 units.

While the use of scrubbers to attain reductions in SO_2 emissions has been increasing, the relative importance of low-sulfur coal in achieving emission reductions has decreased. Ninety-four percent of SO_2 reductions among pre-1972 units resulted from the use of low-sulfur coal. This proportion decreases to 84 percent for 1972-1976 units and 45 percent for post-1976 units. The decline in the use of low-sulfur coal reflects the fact that utilities with units in the East have relied increasingly on scrubbers rather than on low-sulfur coal to meet SO_2 standards.

At oil-fired units, the use of low-sulfur coal results in reductions of 66 percent in potential SO_2 emissions. Post-1976 oil-fired units have both potential emissions and emissions reductions that are higher than earlier units. These quantities indicate that a substantial number of the most recent oil units are still in a "shakedown" period where their high heat rates account for both their high potential emissions and their high emissions reductions per million kWh.

As would be expected from the high efficiencies of TSP control systems among coal-fired units noted in the discussion of compliance strategies, reductions in TSP emissions at these units amount to 98 percent of potential emissions. Recent coal-fired units exhibit smaller reductions in TSP emissions than do earlier coal units. The fact that potential emissions from these more recent units are also lower, however, indicates that a substantial portion of these units burns coal with lower ash contents than do earlier units. (Particulate emissions depend on coal ash content and the quantity of coal burned).

Oil and gas/oil units attain reductions in potential TSP emissions of 84 and 79 percent respectively. Most of these reductions (77 percent for oil units and 92 percent for gas/oil units) result from the burning of low-sulfur oil, and only relatively small reductions are attributed to TSP control systems, which are not generally utilized at oil and gas/oil units. In most cases reductions in TSP emissions from burning low-sulfur oil are incidental to the primary objective of reducing SO_2 emissions.

Cost of Removal

The cost of removing the quantities of pollutants discussed above varies significantly among unit categories. As shown in Table IV-27, for coal units as a whole the average cost of removing SO_2 was nearly two times as high using scrubbers as using low-sulfur fuels ($418 per ton as compared to $229 per ton). For individual units, however, the relationship between equipment and fuel-based removals may be quite different, depending on their access to low-sulfur fuels. (These results do not include western coal-burning units, as no sulfur premium is incurred by these units.)

Sulfur dioxide removal at coal units, whether using a fuel or equipment strategy, is less costly than it is at oil units. Reducing emissions by one ton of SO_2 at coal units costs an average of $229; an equivalent reduction at an oil unit costs $737. Even equipment-based SO_2 removal by using scrubbers at coal units costs slightly less than 60 percent as much as SO_2 removal at oil units.

Although the difference in TSP removal costs appears to be especially dramatic between coal and oil plants, these data must be compared cautiously. Because of the relatively large quantities of TSP removed by the fuel choice and attributed to SO_2 removal strategies, and the small quantities of TSP removed by the equipment choice at oil units, the cost of particulate removal at these units averages $534 per ton. This is compared to $20 per ton to remove TSP at a coal plant. The simultaneous reductions in TSP and SO_2 attributable to the use of low-sulfur, high-quality (e.g., with fewer impurities) oil may make it difficult to properly allocate control costs to the removal of the individual pollutants.

Future Units

As with the analysis of existing units, uncontrolled unit-level emissions of both SO_2 and TSP were calculated assuming that no pollution control equipment would be installed and that coal units in the East would burn high-sulfur coal containing 5 pounds SO_2 per million Btu in the absence of environmental regulations. (The analysis excluded oil-fired units, as it was assumed that only coal would be

Table IV-27

AVERAGE COST PER TON OF SO_2 AND TSP REMOVAL

(1979 dollars per ton)

	SO_2 Removal Strategy: Low-Sulfur Coal	Low-Sulfur Oil[1]	Scrubbers	Total	TSP Equipment
Coal					
Pre-1972	228	371	455	240	21
1972-1976	236	576	330	254	12
Post-1976	222	646	393	318	38
Total Coal	229	412	418	263	20
Oil					
Pre-1972	N/A	738	N/A	738	495
1972-1976	N/A	756	N/A	756	561
Post-1976	N/A	692	N/A	692	a
Total Oil	N/A	737	N/A	737	534
Gas/Oil					
Pre-1972	N/A	780	N/A	780	a
1972-1976	N/A	436	N/A	436	a
Post-1976	N/A	a	a	—	a
Total Gas/Oil	N/A	742	N/A	741	a
National Total	229	721	418	461	22

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]Coal units that also burn oil attain SO_2 reductions using both fuels.

a = Insufficient observations.

N/A = Not applicable.

Source: Energy Database and TBS calculations.

burned in fossil-fuel boilers installed in the future.) To determine quantities of pollutants removed, calculated unit-level emissions based on anticipated compliance strategies (combination of fuel quality and pollution control equipment choices) were subtracted from uncontrolled unit emissions. Calculations of emissions were based on methodologies developed by EPA.

Quantities of Pollutants Removed

Table IV-28 shows potential emissions and calculated removals for SO_2 and TSP among eastern and western units for various standards. The underlying assumptions are that:

Table IV-28

AVERAGE UNIT-CATEGORY
POTENTIAL AIR POLLUTANT EMISSIONS AND REMOVALS

(tons per million kWh)

	SO_2					TSP		
	Removal Strategy					Removal Strategy		
Coal Type	Fuel	Equipment	Total	Potential Emissions	Percent Removed	Equipment	Potential Emissions	Percent Removed
Eastern Low-Sulfur								
NSPS I	18.3	0	18.3	24.0	76	40.1	40.5	99.0
NSPS II	18.3	4.0	22.3	24.0	93	40.4	40.5	99.6
BACT	10.1	12.5	22.6	24.0	94	40.4	40.5	99.6
Eastern High-Sulfur								
NSPS I	0	19.2	19.2	24.0	80	40.1	40.5	99.0
NSPS II	0	21.6	21.6	24.0	90	40.4	40.5	99.6
BACT	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Western Low-Sulfur								
NSPS I	0	0	0	4.9	0	48.1	48.6	99.0
NSPS II	0	3.4	3.4	4.9	70	48.4	48.6	99.6
BACT	0	4.4	4.4	4.9	90	48.4	48.6	99.6

N/A = Not applicable.

Source: EPA.

- NSPS I apply to units whose boilers were ordered before September 1979. (For purposes of this analysis, in-service date is prior to 1985.) These units will meet a standard of 1.2 pounds SO_2 per million Btu.

- NSPS II apply to units whose boilers were ordered after September 1979. (In this analysis, in-service date is 1985 or later.) These units must comply with the standard by scrubbing high-sulfur coal with 90 percent removal efficiency (for SO_2) or by scrubbing low-sulfur coal with 70 percent removal efficiency.

- More stringent BACT requirements dictate that, on a case-by-case basis, removals will exceed NSPS II requirements. Generally, this is accomplished through full scrubbing (90 percent removal) of low-sulfur coals.

Three types of model facilities are presented in Table IV-28. The first uses a control strategy that combines eastern low-sulfur coal and scrubbers. The quality of coal varies from 1.2 pounds SO_2 per million Btu for NSPS I and II compliance to 2.9 pounds SO_2 per million Btu for BACT compliance, while equipment choices vary from no scrubbing to partial or full scrubbing. The eastern high-sulfur coal strategy combines local bituminous coal containing 5.0 pounds SO_2 per million Btu with scrubbers that remove 80 to 90 percent of the SO_2. The western low-sulfur coal facility uses a lignite/sub-bituminous coal that is representative of western coal regions. It contains 1 pound SO_2 per million Btu and, to meet standards that exceed NSPS I, it is combined with dry-scrubbing equipment choices that range from 70 percent to 90 percent removal.

Potential, uncontrolled, emissions are based on the emissions factors described above for eastern high-sulfur and western low-sulfur coals, and heat rates of 9,600 and 9,800 Btu per kWh, respectively. As shown in Table IV-28, these specifications lead to substantial differences among model facilities and standards in uncontrolled and controlled quantities of SO_2.

Potential emissions of TSP are based on ash contents of 12 percent for eastern coals and 9.2 percent for western coals. The highly efficient TSP control systems remove at least 99 percent of potential emissions, whether the equipment is a baghouse for western low-sulfur coals or an ESP system for eastern coals.

Cost of Removal

Table IV-29 presents the average costs of removing a ton of SO_2 and TSP for the strategies described above. The costs are not for incremental controls, that is, moving from NSPS I to NSPS II to BACT. Rather, they are the costs of alternative levels of stringency from uncontrolled emission levels.

Table IV-29

AVERAGE COST PER TON OF SO_2 AND TSP REMOVAL

(1979 dollars per ton)

	Removal Strategy			
	SO_2			TSP
Coal Type	Low-Sulfur Fuel	Equipment	Total	Equipment
Eastern Low-Sulfur				
NSPS I	219	0	219	47
NSPS II	219	1,145	385	80
BACT	236	721	504	42
Eastern High-Sulfur				
NSPS I	0	261	261	47
NSPS II	0	417	417	47
BACT	N/A	N/A	N/A	N/A
Western Low-Sulfur				
NSPS I	0	0	0	68
NSPS II	0	1,347	1,347	67
BACT	0	1,663	1,663	58

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

N/A = Not applicable.

Source: EPA and TBS calculations.

Removal costs for future units are dominated by scrubbers. This is particularly apparent in the NSPS II and BACT strategies for low-sulfur coal. However, these data must be considered with caution; while the cost-effectiveness analysis for existing units was based on actual utility submissions in the Energy Database, this projected analysis is based on engineering estimates, and it is estimated that engineering control costs are only accurate within plus or minus 30 to 40 percent.

V. REGIONAL EFFECTS

CHAPTER V

REGIONAL EFFECTS OF ENVIRONMENTAL REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

CONTENTS

V. REGIONAL EFFECTS OF ENVIRONMENTAL REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

INTRODUCTION AND MAJOR FINDINGS

Building on the unit-category analyses of the previous chapter, this chapter highlights the effects environmental regulations are likely to have on EPA's ten regions and the differences among regions. It presents methodology and assumptions used in this regional analysis, the regional distribution of current and future capacity, and compliance costs among units. It shows the components of costs by pollutant controlled and by types of costs. The chapter closes with a qualitative discussion of pollution control requirements under the attainment and nonattainment programs.

Each of the ten EPA regions has a unique profile of existing capacity by age of unit and fuel type and, therefore, is affected differently by environmental regulations. Each region's profile, and the changes in the mix due to growth within a region over time, influences the most likely range of pollution control strategies for the region. The strategies, whether they involve equipment or fuels upgrading, are translated into costs that the average regional customer pays for its service.

Generally, units in the eastern regions are older than in the western regions. More than 30 percent of eastern capacity was installed before 1960; only 6 percent of western capacity is of that vintage. Seventy-five percent of coal-fired capacity and 45 percent of oil- and gas-fired capacity is in the East.

Regional variations in the average costs of compliance for unit categories capture the effects of differing fuel mixes, fuel quality, and preferred compliance strategies. These are summarized in Table V-1. Although the national average cost of pollution control across all units is 3.88 mills per kWh, regional costs range from a high of 8.35 mills per kWh in Region I to a low of 1.07 mills per kWh in Region VI. In every region except Regions VI and VIII (which have relatively low average costs), low-sulfur fuel premiums dominate the costs.

Existing Capacity: Costs of Compliance

Oil-fired units rely exclusively on low-sulfur fuel to achieve compliance with sulfur dioxide (SO_2) standards. This

Table V-1

DETERMINANTS IN REGIONAL POLLUTION CONTROL COSTS

EPA Region	Dominant Capacity Type	Reasons for Costs (in order of relative magnitude)	Weighted Average Unit-Category Costs of Compliance (mills/kWh)
I	Pre-77 oil units	Fuel (oil) premium	8.35
II	Pre-77 coal and oil units	Fuel (coal and oil) premium; FGD capital and operating costs	6.18
III	Pre-77 coal and oil units	Fuel (coal and oil) premium; pre-72 coal FGD, TSP, and chemical control	4.36
IV	Coal units, and pre-72 oil units	Fuel (coal and oil) premium; coal pre-72 TSP and chemical control	4.41
V	Coal units especially pre-72	Fuel (coal) premium; TSP control; chemical control	3.73
VI	Post-72 coal units, pre-72 gas units	Thermal and chemical control	1.07
VII	Coal units; pre-72 gas units	Fuel (oil) premium for coal units that also burn oil; TSP control	4.53
VIII	Coal units, especially post-76	TSP control; FGD for post-76 units; thermal and chemical control	2.94
IX	Pre-72 oil and gas units; pre-77 coal units	Fuel (oil) premium; thermal and chemical control for coal and oil units	4.53
X	72-76 coal units; pre-77 oil units	Fuel (oil) premium; TSP control; thermal and chemical control for coal units	2.35

Source: Energy Database and TBS calculations.

is reflected in the national average fuel oil premium of 6.86 mills per kWh, and substantially affects the eastern regional costs. Region I, with 99 percent of its fossil-fuel capacity in oil units, faces a low-sulfur oil premium of 7.56 mills per kWh, more than 90 percent of Region I's average pollution control costs. Without a change in capacity mix in the future, Region I's utility customers will face an even greater differential in costs if, as projected, the fuel oil premium escalates at a more rapid rate than the cost of alternative compliance methods.

The relatively high costs in Region II are driven by SO_2 control strategies at both oil-fired and coal-fired units. More than half of Region II's generation is provided by oil-fired units; one-quarter of that capacity was in service before 1972. The costs of SO_2 control at coal units in Region II demonstrate the evolution of compliance strategies over time. Units installed before 1972 depend exclusively on improved fuel quality, while units installed after 1972 reflect the influence of new source performance standards (NSPS I) requirements in environmental standards. These units combine lower sulfur (but not compliance) coal with flue gas desulfurization (FGD) equipment. Costs for the 1972-1976 units are no greater than for the pre-1972 units, but units installed after 1976, in meeting the NSPS I emissions limit of 1.2 pounds of SO_2 per million Btu, face a tripling of costs for SO_2 control.

Coal-fired capacity in Region VIII accounts for three-fourths of its total fossil-fuel capacity, with nearly one-third of the coal capacity in NSPS I units. Control costs for units with in-service dates after 1976 are 150 percent greater than the average costs for units of all vintages. The components of the high pollution control costs include total suspended particulate (TSP) control systems, FGD equipment, thermal control equipment, and energy penalties and operating costs associated with the capital strategies. These costs reflect, at a minimum, the compliance requirements of the next two decades, as new coal units are subject to NSPS I, NSPS II, and at times even stricter best achievable control technology (BACT) requirements.

Expansion plans for utilities during the 1980s are projected to favor nuclear and coal capacity. All regions will participate in the growth of nuclear capacity, which will nearly double by 1990 if units currently under construction are completed as planned. Pollution control requirements for nuclear units resemble gas units in their emphasis on thermal and chemical control and in their low costs of compliance. Oil and gas conversions to coal will contribute to a substantial increase in coal capacity in Regions I, II, III, and IV, and new coal capacity will dominate total additions in all regions except IX and X.

New Coal-Fired Capacity: Costs of Compliance

The emphasis on new coal-fired capacity will present significant environmental concerns during the 1980s. Although NSPS I standards can be met without installing scrubbers, it is expected that eastern units generally will install FGD equipment with removal efficiencies of 85 to 90 percent and will burn high-sulfur coal. In the West, approximately one-third of all new capacity in Regions VI and VII will be scrubbed, and nearly all new capacity in Region VIII will be scrubbed.

The national average cost of compliance for SO_2, TSP, thermal and chemical control for new 1980-1984 coal-fired capacity is 7.4 mills per kWh. The range is broad, from a low of 5.3 mills per kWh in Regions IX and X where using low-sulfur coal is the preferred strategy and scrubbers are infrequently installed, to a high of 8.6 mills per kWh in Region VIII where scrubbers with removal efficiency of 90 percent are combined with fuel that has less than 0.8 percent sulfur content.

Specific compliance strategies for NSPS II additions in the latter half of 1980 and beyond are more difficult to predict, although scrubbers will be required on all coal-fired units. Individual units may choose a strategy of higher quality coal and 70 percent removal efficiency in the scrubber design or lower quality coal and 90 percent design removal efficiency. On the basis of the assumptions described in Chapter IV, eastern NSPS II compliance strategies are projected to cost 12.4 mills per kWh, while western compliance strategies will cost 9.4 mills per kWh.

National Issues That Affect Compliance

Several issues that are national in scope may have a bearing on future regional compliance requirements and costs. These include regional growth patterns and their effects on emissions, PSD and regional air-quality-related values, and regional siting in attainment and nonattainment areas.

Changes in growth patterns can have a noticeable effect on air quality and on the level of control necessary to achieve and maintain the National Ambient Air Quality Standards (NAAQS). The Clean Air Act requires that states incorporate in their state implementation plans (SIPs) the application of appropriate controls based on growing or diminishing emissions. If industrial growth occurs at a higher than predicted rate in the Southeast or Southwest, or if conversions to coal increase SO_2 emissions in the East, powerplants may be required to meet more stringent emission limitations by installing complex and costly equipment.

Visibility impairment, particularly in the West, and acid precipitation, particularly in the East, are two air-quality-related values that may be the focus of much attention over the next few years. An important element of the PSD program is the consideration of these values during review of a permit application. To the extent that objectives in these areas change, and lead to changes in PSD requirements, compliance strategies and costs will change over time.

The technology requirement for a major source in attainment areas is less stringent than the requirement in nonattainment areas. Further, the offset requirement exists only in nonattainment areas. In practice, technology determinations have been similar in the two areas and offsets have been available. Therefore, to date siting in PSD areas has not occurred at the expense of nonattainment areas. In the future, growth may be limited in nonattainment areas if offsets are unavailable or extremely costly, although interregional effects are difficult to quantify at this time.

RESEARCH METHODOLOGY

The approach to the regional analysis includes the extension of unit-category data to regional areas and the development of region-specific baseline and pollution control costs.

Selection of Regional Boundaries

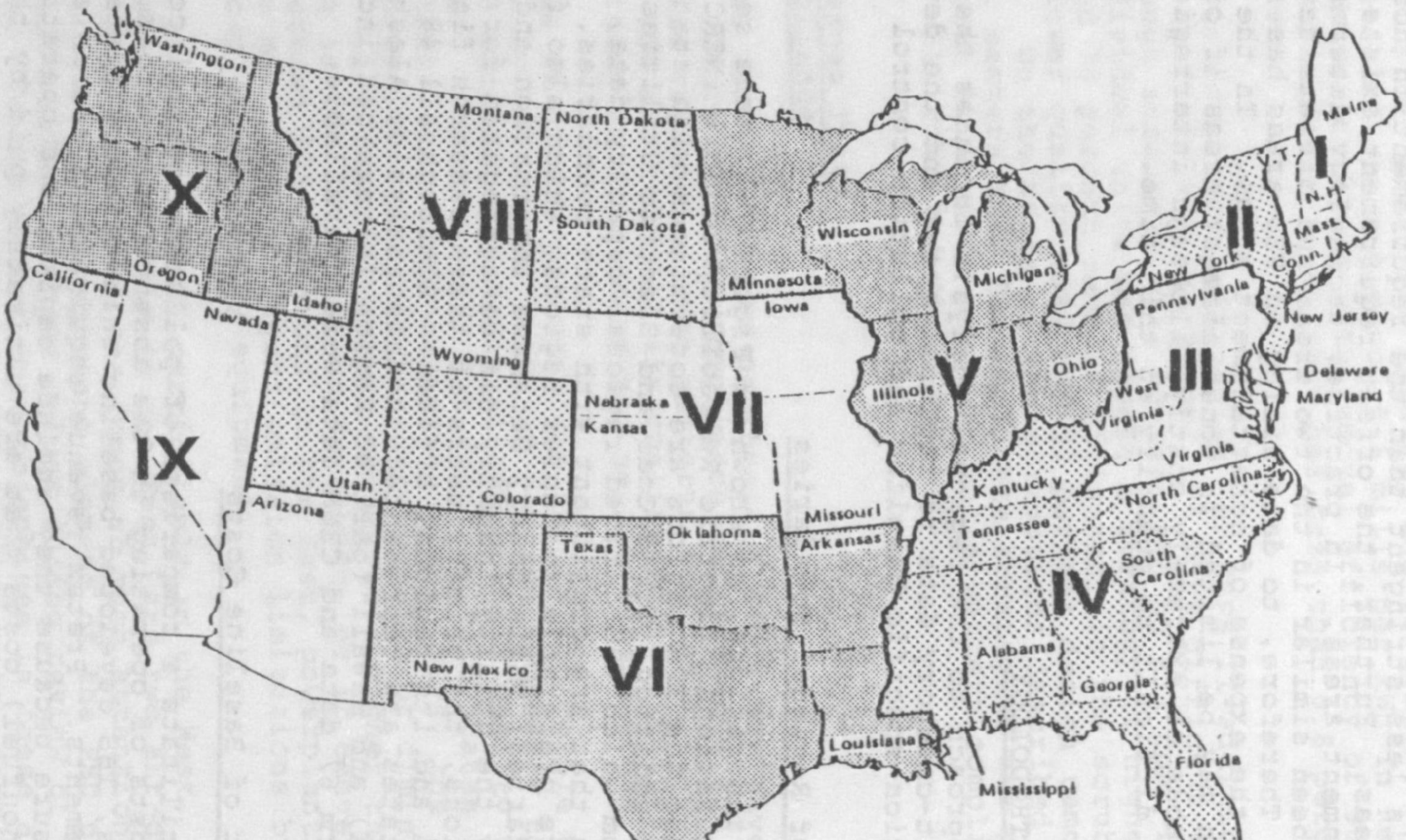
EPA's ten regions, as shown in Figure V-1, were selected rather than National Electric Reliability Council (NERC) regions because the EPA regions are coterminous with state boundaries. In addition, ICF's Coal and Electric Utilities Model (CEUM), from which TBS derived regional capacity data, generates data that are consistent with state boundaries. EPA regions were preferable to Census regions, which also follow state boundaries; while Energy Database information and data provided by the utility industry can be aggregated for either set of regions, the primary users of these research findings will be EPA and its regional offices. Although all 48 continental states are represented in this analysis, Alaska (part of Region X) and Hawaii (part of Region IX) are not included because Form 67 data and CEUM data were unavailable.

Development of Baseline Costs

To facilitate a comparison of pollution control costs with the costs of operating in the absence of environmental regulations, TBS developed baseline unit-category pretax revenue requirements. Pretax revenue requirements are an appropriate measure because they include capital and operating (fuel and nonfuel) costs that are ultimately paid by the ratepayers.

Figure V-1

EPA REGIONS



The methodology described in Chapter IV for the unit-category analysis was applied to the regional analysis with one modification: the baseline fuel price for high-sulfur coal in the East is greater than the baseline price for low-sulfur coal available in the West. That differential, amounting to 1.2 mills per kWh, is incorporated in the eastern and western unit-category costs of generation at coal-fired units.

Development of Pollution Control Costs

The approach used to develop the regional pollution control costs for coal-, oil-, and gas-fired units parallels that used for the unit-category analysis. Each region's costs of compliance were derived from the Energy Database using the same computational logic and types of assumptions as those described in the previous chapter. Wherever possible, data were incorporated that reflected differences among regions; examples include the use of location-specific fuel premiums and the distributions of capacity additions to appropriate regions by fuel type. Some data, such as capital charge rates, were available only at the national level. These were applied uniformly to all regions.

REGIONAL DISTRIBUTION OF CURRENT CAPACITY AND COSTS

The following paragraphs discuss the distribution of current capacity, and the baseline revenue requirements and pollution control compliance costs among the EPA regions.

Current Capacity by Region

Table V-2 shows the distribution of regional capacity by prime mover. Included in these data are fossil-fuel, nuclear, and hydro (including pumped storage) units. Omitted from the table are the megawatts of internal combustion/gas turbine (IC/GT) power, which account for approximately 8.6 percent of total U.S. electric utility capacity. These data were not available on a regional level in a form consistent with data for other fuel types.

An examination of the distribution of capacity among regions shows that all regions differ markedly from the national distribution of 44.6 percent coal, 31.4 percent gas and oil, 9.5 percent nuclear, and 14.5 percent hydro. The greatest deviations from the national average occur in Region I, where 82.3 percent of the capacity is provided by oil-fired and nuclear units; Region VIII, where 98.5 percent of capacity is provided by coal-fired and hydro units; Region IX, where 84.5 percent of capacity is provided by oil-fired, gas-fired, and hydro units; and finally Region X, where 91 percent of capacity is hydro.

Table V-2

1979 REGIONAL CAPACITY BY FUEL TYPE[1]

(MW and percent of total)

EPA Region	Coal MW	Coal %	Oil and Gas MW	Oil and Gas %	Nuclear MW	Nuclear %	Hydro MW	Hydro %	Total MW	Total %
I	486	2.7	10,684	59.1	4,199	23.2	2,708	15.0	18,077	100
II[3]	4,286	11.0	20,630	53.0	7,537	19.4	6,487	16.6	38,940	100
III[4]	33,611	63.0	11,941	22.4	5,948	11.2	1,818	3.4	53,318	100
IV	62,363	57.8	20,158	18.7	12,831	11.9	12,475	11.6	107,827	100
V	72,498	75.0	8,602	8.9	12,425	12.9	3,075	3.2	96,600	100
VI	14,941	19.2	59,592	76.5	850	1.1	2,524	3.2	77,907	100
VII	20,278	75.5	3,620	13.5	1,773	6.6	1,181	4.4	26,832	100
VIII	12,025	68.8	262	1.5	0	0.0	5,196	29.7	17,483	100
IX	5,231	12.2	24,259	56.4	1,411	3.3	12,089	28.1	42,990	100
X	1,300	4.5	44	0.2	1,130	3.9	26,299	91.4	28,773	100
Total	227,019	44.6	159,792	31.4	48,104	9.5	73,852	14.5	508,765	100

Fuel Type[2]

[1]Capacity as of end of 1979.
[2]Excludes combined cycle and geothermal.
[3]Includes eastern Pennsylvania.
[4]Excludes eastern Pennsylvania.

Source: ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981; and Energy Database.

Each of the ten EPA regions has a unique profile of existing fossil-fuel capacity by age of units and fuel type. This profile, as shown in Table V-3, and the changes in the mix due to growth within a region over time, influence the most likely range of pollution control strategies for the region. The strategies, whether they are capital-intensive or fuel choices, are translated into costs that the average regional customer pays for its service. Nationally, current coal-fired and noncoal-fired units contribute approximately 58 percent and 42 percent, respectively, to all fossil-fuel capacity. Coal is the predominant fossil fuel in Regions III, IV, V, VII, VIII, and X; gas is dominant only in Region VI; and oil is dominant only in Region I but is important in Region II as well.

As shown in Table V-3, in more than half the regions (II, III, IV, V, VI, VII, and IX) at least 55 percent of the units were installed prior to 1972. The Energy Database further reveals that, based on in-service year, Region V has the largest share of units that would be candidates for replacement during the 1980s, followed closely by Regions III and IV. Regions VII and VIII have added the largest percentage of NSPS I coal-fired units to their inventories since 1976; these units and units planned for start-up in the early 1980s contribute substantially to the fossil-fuel capacity in their regions.

Baseline Costs

Based on the Energy Database, generation in the East (Regions I-V) is dominated by oil- and coal-fired units while generation in the West (Regions VI-X) is spread more evenly across coal-, gas-, and gas/oil-fired units. This results in a slightly higher baseline cost of generation for western units than for eastern units, as shown in Table V-4. Specifically, the weighted average baseline costs for eastern and western regions are 26.7 mills per kWh and 27.7 mills per kWh, respectively.

Compliance Costs

The previous chapter discussed the components of the average costs within unit categories of controlling pollution. The national average cost of 3.88 mills per kWh is composed of air, water, and waste pollution control costs. These costs are the aggregation of capital, operating, energy penalty, and fuel premium costs, and incorporate strategies adopted by operating units throughout the country. This section discusses regional variations in the average costs of compliance within unit categories to capture the range of effects caused by differing plant ages, fuel mixes, fuel quality, and preferred compliance strategies.

Table V-3

FOSSIL STEAM UNITS
TYPE OF CAPACITY BY IN-SERVICE YEAR

(percent of total fossil capacity in region in 1979)

EPA Region	Unit Categories: Coal Units In-Service Year			Oil Units In-Service Year			Gas Units In-Service Year			Gas/Oil Units In-Service Year			All Fossil-Fuel Units			
	Pre-72	72-76	77-79	Pre-72	72-76	77-79	Pre-72	72-76	77-79	Pre-72	72-76	77-79	Coal	Oil	Gas	Gas/Oil
I	0	0	0	48.1	50.9	0	0	0	0	1.0	0	0	0	99.0	0	1.0
II	14.5	4.1	4.1	23.6	19.6	1.9	4.5	0	0	24.8	3.0	0	22.6	45.1	4.5	27.8
III	59.3	17.9	3.8	8.3	8.2	2.4	0	0	0	0	0	0	81.1	18.9	0	0
IV	49.7	17.8	5.5	3.5	5.8	2.6	1.2	0.1	0	12.5	0.8	0.5	73.0	11.9	1.3	13.8
V	66.9	11.7	8.4	3.2	1.2	6.1	0.2	0	0	2.3	0	0	87.0	10.5	0.2	2.3
VI	5.7	3.3	4.7	0.3	0.3	0	48.9	16.8	2.0	10.1	7.9	0	13.7	0.6	67.7	18.0
VII	41.5	9.8	32.2	0	0	0	2.2	0.5	0	13.3	0.6	0	83.4	0	2.7	13.9
VIII	18.5	34.6	23.3	0	0	0	11.3	4.3	5.0	3.1	0	0	76.3	0	20.6	3.1
IX	7.6	10.2	2.6	6.1	1.0	1.5	4.6	2.1	0	61.1	3.2	0	20.4	8.6	6.7	64.3
X	0	69.7	0	15.1	15.1	0	0	0	0	0	0	0	69.7	30.2	0	0
National Average	38.2	12.7	6.7	6.3	5.6	2.5	9.2	3.0	0.5	13.3	2.0	0.1	57.6	14.4	12.6	15.4

Source: Energy Database.

Table V-4

BASELINE COSTS OF GENERATING ELECTRICITY IN 1979 AT UNIT CATEGORIES SELECTED FOR ANALYSIS

(1979 mills/kWh)

EPA Regions	Fuel Type: Coal	Oil	Gas	Gas/Oil	Average All Fuels[1]
I-V (Eastern)	24.2	37.4	28.5	31.3	26.7
VI-X (Western)	23.0	37.4	28.5	31.3	27.7

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]Weighted average based on generation in each fuel category.

Source: Energy Database and TBS calculations.

Table V-5 arrays the determinants of regional pollution control costs. The major causes of compliance costs across all regions are the fuel oil and coal premiums that are paid to upgrade the quality of the fuel by reducing the sulfur content. Oil-fired units rely exclusively on low-sulfur fuel to achieve compliance with SO_2 standards. At coal-fired units, a fuel-switching strategy is used more frequently than an equipment strategy, although sometimes a switch to moderately improved fuel quality will be combined with FGD equipment that removes less sulfur from the fuel (see Tables IV-9 and IV-10 in the previous chapter).

Table V-5

DETERMINANTS IN 1979 REGIONAL POLLUTION CONTROL COSTS

EPA Region	Dominant Fossil-Fuel Strategy	Reasons for Costs (in order of relative magnitude)
I	Pre-77 oil units	Fuel (oil) premium
II	Pre-77 coal and oil units	Fuel (coal and oil) premium; FGD capital and operating costs
III	Pre-77 coal and oil units	Fuel (coal and oil) premium; pre-72 coal FGD, TSP, and chemical control
IV	Coal units and pre-72 oil units	Fuel (coal and oil) premium; coal pre-72 TSP and chemical control
V	Coal units especially pre-72	Fuel (coal) premium; TSP control; chemical control
VI	Post-72 coal units, pre-72 gas units	Thermal and chemical control
VII	Coal units; pre-72 gas units	Fuel (oil) premium for coal units that also burn oil; TSP control
VIII	Coal units, especially post-76	TSP control; FGD for post-76 units; thermal and chemical control
IX	Pre-72 oil and gas units; pre-77 coal units	Fuel (oil) premium; thermal and chemical control for coal and oil units
X	72-76 coal units; pre-77 oil units	Fuel (oil) premium; TSP control; thermal and chemical control for coal units

Source: Energy Database and TBS calculations.

As shown in Table V-6, pollution control costs incurred by each region range from a low of 1.07 mills per kWh in Region VI to a high of 8.35 mills per kWh in Region I. The associated percent increase over average baseline costs at each end of the range is 4 percent and 31 percent, respectively. Gas-fired units incur the smallest incremental costs; generally they are at or below 1 mill per kWh and represent an increase of no more than 4 mills per kWh across all regions. Gas/oil units would show low costs but for the fuel oil premium associated with lower sulfur oil. Although more than 50 percent of the generation from gas/oil units is gas-fired, the oil premium carries a disproportionately large share of total incremental costs and yields effects as high as 26 percent over baseline in Region I and 22 percent over baseline in Region II.

Table V-6

REGIONAL AVERAGE ANNUALIZED COSTS OF COMPLYING WITH AIR, WATER, AND SOLID WASTE REGULATIONS IN 1979

(1979 mills/kWh and percent increase over baseline costs)

EPA Region	Coal mills/kWh	Coal %	Oil mills/kWh	Oil %	Gas mills/kWh	Gas %	Gas/Oil mills/kWh	Gas/Oil %	All Fuels mills/kWh	All Fuels %
I	0	0	8.35	22	0	0	8.04	26	8.35	31
II	5.24	22	6.50	17	0.02	0	6.80	22	6.18	23
III	3.80	16	8.73	23	0	0	0	0	4.36	16
IV	4.10	17	7.71	21	0.84	3	4.11	13	4.41	17
V	3.46	14	8.74	23	0.74	3	5.00	16	3.73	14
VI	2.03	9	4.88	13	0.56	2	2.50	8	1.07	4
VII	5.02	22	0	0	1.08	4	1.71	5	4.53	16
VIII	3.28	14	0	0	0.50	2	2.49	8	2.94	11
IX	1.76	8	9.93	27	0.33	1	5.48	18	4.53	16
X	1.31	6	12.14	32	0	0	0	0	2.35	8
National Average	3.68	15	7.89	21	0.55	2	4.72	15	3.88	14

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

Source: Energy Database and TBS calculations.

Oil-fired units in all regions experience increases of at least 13 percent over baseline and reach a high of 32 percent in Region X, where there is very little oil-fired capacity but where the fuel premium is more than 10 mills per kWh on a base of 3.74 mills per kWh. The effects of the fuel premium on average costs of generating electricity in Region X would be even more dramatic than they are, but coal-fired capacity, which is relatively less expensive in terms of meeting environmental compliance requirements due to the absence of a fuel premium, is used more extensively than oil-fired capacity.

Coal-fired unit compliance costs range from a low of 1.31 mills per kWh to a high of 5.24 mills per kWh, or 6 percent to 22 percent, respectively, over baseline operating costs. The differences are a function of the compliance strategies chosen, availability of low-sulfur coal (which carries a premium in the East but not in the West), and the extent to which low-sulfur oil (which carries a premium in every region) is burned in units that also burn coal. For example, at coal-fired units in Region VII, the high costs relative to baseline are caused primarily by oil premiums, not by the use of low-sulfur coal, for those units that have multifuel capabilities.

Table V-7 shows the range of costs associated with SO_2, TSP, thermal, and chemical pollution control strategies across the regions. Region I, with 99 percent of its fossil-fuel capacity in oil units, pays an unusually high fuel premium associated with SO_2 compliance. In fact, its fuel premium exceeds the national average by more than 200 percent.

Table V-7

AVERAGE ANNUALIZED COSTS OF COMPLIANCE BY POLLUTANT FOR TYPICALLY AFFECTED FOSSIL STEAM UNITS IN 1979

(1979 mills/kWh)

	Pollution Control Strategy Costs					
	SO_2 Control					
EPA Region	FGD	Fuel	TSP Control	Thermal Control	Chemical Control	Total
I	0	7.56	0.24	0.02	0.53	8.35
II	0.59	4.56	0.30	0.15	0.48	6.18
III	0.35	2.93	0.41	0.28	0.40	4.36
IV	0.13	3.01	0.42	0.38	0.48	4.41
V	0.28	1.85	0.80	0.28	0.53	3.73
VI	0.07	0.38	0.05	0.27	0.30	1.07
VII	0.36	2.65	0.88	0.19	0.45	4.53
VIII	0.44	0.05	1.26	0.72	0.47	2.94
IX	0.11	3.72	0.10	0.21	0.40	4.53
X	0	1.00	0.51	0.44	0.39	2.35
National Average	0.23	2.48	0.43	0.30	0.44	3.88

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

Source: Energy Database and TBS calculations.

Compared to the fuel premium component of SO_2 control, FGD strategies account for a lesser portion of the total costs of control. Regions II and VIII have relatively high costs for similar FGD strategies but for different reasons: Region II's units are older and located in more densely populated areas with poorer air quality, and Region VIII's units are newer--almost one-third of the coal capacity is in NSPS I units--and current control costs are 150 percent greater than the average costs for units of all vintages. Region IX's costs for SO_2 control are much lower than average because the coal-fired generation is not scrubbed and the coal that meets the emission standards carries no fuel premium, as low-sulfur coal is generally available in the West at prices equal to those of eastern high-sulfur coal.

TSP control accounts for a relatively large share of total costs in regions with a dependence on coal-fired units, as all coal capacity is subject to TSP control. Region VIII is a particularly good example, where the fossil-fuel capacity is split between coal and gas (and gas/oil)--76 percent and 24 percent, respectively, with no oil-fired units. While the national average contribution of TSP control costs to total control costs is about 11 percent, TSP costs in Region VIII account for 40 percent of the total.

As a percentage of total costs, thermal and chemical control costs in Region X exceed the national average by 100 percent. This is because these environmental regulations affect all coal and oil units, and Region X's fossil capacity is exclusively coal and oil.

An examination of the data in Table V-8 indicates that there is wide regional variation from the national average distribution of capital, operating, energy penalty, and fuel premium component costs. Nationally, capital costs account for 19 percent, operations and maintenance for 13 percent, energy penalties for 4 percent, and low-sulfur fuel premiums for 64 percent (see Table IV-22 in Chapter IV). Regionally, nonfuel costs of control contribute 98 percent to Region VIII's total costs (2.89 mills/kWh out of a total of 2.94 mills/kWh), due to the lack of a fuel premium on low-sulfur coal. Alternatively, nonfuel cost contribute 10 percent to Region I's total costs, as oil-burning units dominate the generation.

Table V-8

1979 UNIT-CATEGORY COSTS OF
COMPLIANCE BY COST COMPONENT
TOTAL AIR, WATER, AND SOLID WASTE

(1979 mills/kWh)

EPA Region	Capital	O&M	Energy Penalty	Fuel Premium	Total
	Cost Components				
I	0.37	0.41	0.12	7.56	8.35
II	0.80	0.73	0.08	4.56	6.18
III	0.66	0.63	0.15	2.93	4.36
IV	0.76	0.47	0.17	3.01	4.41
V	1.11	0.71	0.14	1.85	3.73
VI	0.22	0.29	0.18	0.38	1.07
VII	1.28	0.45	0.15	2.65	4.53
VIII	1.83	0.70	0.36	0.05	2.94
IX	0.32	0.38	0.12	3.72	4.53
X	0.63	0.44	0.27	1.00	2.35
National Average	0.72	0.53	0.15	2.48	3.88

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

Source: Energy Database and TBS calculations.

REGIONAL DISTRIBUTION OF FUTURE CAPACITY AND COMPLIANCE COSTS: 1980-1990

Current compliance strategies and costs present an incomplete picture of the effects of environmental regulations on the electric utility industry. Measuring the full effects also requires assessing the costs associated with future requirements of those regulations on both existing and new capacity.

Key Assumptions

This analysis depends on estimates of changes in energy demand growth--the year-to-year change in the total kilowatt-hours of generation; peak demand--the maximum rate of demand during a time period, usually a year--and reserve margin--the difference between the system's capacity and the anticipated annual peak demand. A reserve margin is maintained so that power can still be provided at the time of peak demand, even though the system's capacity may be temporarily reduced because of the failure of one or more generating units.

In a related study, EPA developed estimates of electricity demand growth and other key capacity assumptions. According to EPA, aggregate demand will grow 3.0 percent per year during 1979-2005. (That reflects a change from earlier forecasts of 3.4 percent per year during the period 1979-1990.) ICF, Inc., allocated the near-term growth to regions, based on responses of representative utility companies and state utility commissions, to a survey of projected 1979-1985 plans. TBS then revised the regional growth forecasts to reflect the lower aggregate demand growth estimates.

Growth rates in regional demand for the periods 1979-1985 and 1985-1990 are shown in Table V-9. The particularly high projection in Region VIII is driven by EPA/DOE assumptions regarding the completion of major energy projects. The relatively low estimate in Region I assumes adequate existing capacity in 1979 and little growth in the industrial, commercial, and residential sectors in the Northeast. Growth in peak demand is assumed to be the same as growth in energy demand throughout the forecast period. Underlying assumptions are that transmission and distribution losses remain at 10 percent of total generation, and that the reserve margin varies from 36 to 20 percent nationally and within regions.

These key assumptions, in concert with the industry's plans for reconversions, additions, and retirements, provide the basis for EPA's projections of 1979 capacity estimates to future periods. As shown in Tables V-10 and V-11, nuclear capacity should nearly double by 1990 if units currently under construction are completed as planned, and all regions will participate in that growth. The strategies for gradually decreasing oil and gas use will lead to a substantial increase in coal capacity in Regions I through V, and new coal capacity will be the dominant strategy in Region VI.

Table V-9

PROJECTED GROWTH OF REGIONAL DEMAND FOR ELECTRICITY 1979 TO 1990

(percent)

EPA Region	Annual Growth Rate 1979-1985	1985-1990
I	1.80	1.80
II	1.99	1.99
III	2.01	2.02
IV	3.11	3.12
V	3.26	3.26
VI	3.88	3.85
VII	2.99	2.98
VIII	5.21	4.19
IX	1.94	1.95
X	3.73	3.72
Average All Regions	3.00	3.00

Source: EPA—aggregate forecast; and ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981.

Retired Capacity

Retirements will play a minor role in capacity expansion plans during the 1980s. Although EPA and DOE estimated for the purpose of their earlier study that about 3,500 MW of coal-fired capacity would be retired during that period, ICF's regional distribution of capacity changes did not reflect that change. The Energy Database sheds some light on the question of the expected turnover of coal-fired units. Assuming, as EPA and DOE did, that the average life of a unit is 45 years, units in service before 1945 would be retired by 1990. Less than 1 percent of the capacity--about 1,200 MW--would be candidates for retirement. Virtually all capacity older than 45 years is small (less than 50 MW each), in the eastern regions, and concentrated in Region V. Since other capacity changes occurring simultaneously would have far more impact on the cost of generation, no attempt has been made to account for specific regional changes resulting from retirements.

Table V-10

1985 REGIONAL CAPACITY BY FUEL TYPE

(MW and percent of total MW)

EPA Region	Coal MW	Coal %	Oil and Gas MW	Oil and Gas %	Nuclear MW	Nuclear %	Hydro MW	Hydro %	Total MW	Total %
I	2,258	12.5	8,912	49.3	4,199	23.2	2,708	15.0	18,077	100
II[2]	6,074	15.6	18,842	48.4	7,537	19.4	6,487	16.7	38,940	100
III[3]	39,086	68.7	8,937	15.7	7,048	12.4	1,818	3.2	56,889	100
IV	68,722	59.9	15,701	13.7	15,966	13.9	14,378	12.5	114,767	100
V	78,179	74.0	8,602	8.1	15,816	15.0	3,075	2.9	105,672	100
VI	25,930	28.2	59,529	64.7	4,077	4.4	2,524	2.7	92,060	100
VII	23,470	75.2	3,620	11.6	2,923	9.4	1,181	3.8	31,194	100
VIII	16,405	74.5	262	1.2	0	0	5,350	24.3	22,017	100
IX	6,431	12.9	24,259	48.7	4,011	8.1	15,105	30.3	49,806	100
X	1,830	5.5	44	0.1	2,223	6.7	29,105	87.7	33,202	100
Total	268,385	45.7	148,708	26.0	63,800	14.0	81,731	14.3	562,624	100

Fuel Type[1]

[1]Excludes combined cycle and geothermal.
[2]Includes eastern Pennsylvania.
[3]Excludes eastern Pennsylvania.

Source: ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981, and EPA revised capacity expansion plan.

Table V-11

1990 REGIONAL CAPACITY BY FUEL TYPE

(MW and percent of total MW)

Fuel Type[1]

EPA Region	Coal MW	Coal %	Oil and Gas MW	Oil and Gas %	Nuclear MW	Nuclear %	Hydro MW	Hydro %	Total MW	Total %
I	4,431	22.9	6,739	34.9	5,349	27.7	2,803	14.5	19,322	100
II[2]	13,713	31.2	14,311	32.5	9,205	20.9	6,767	15.4	43,996	100
III[3]	42,236	70.2	5,787	9.6	9,037	15.0	3,134	5.2	60,194	100
IV	77,672	61.8	9,860	7.8	23,785	18.9	14,378	11.4	125,695	100
V	86,209	73.5	6,775	5.8	21,234	18.1	3,075	2.6	117,293	100
VI	38,839	36.1	59,592	55.4	6,577	6.1	2,524	2.4	107,532	100
VII	26,363	74.7	3,620	10.3	2,923	8.3	2,403	6.8	35,309	100
VIII	19,479	77.6	262	1.0	0	0	5,350	21.3	25,091	100
IX	10,308	17.6	24,259	41.4	8,861	15.1	15,105	25.8	58,533	100
X	2,170	6.0	44	0.1	4,713	13.1	29,105	80.8	36,032	100
Total	321,420	45.9	131,249	22.6	91,684	17.4	84,644	14.1	628,997	100

[1]Excludes combined cycle and geothermal.
[2]Includes eastern Pennsylvania.
[3]Excludes eastern Pennsylvania.

Source: ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981, and EPA revised capacity expansion plan.

Reconverted and New Coal-Fired Capacity

Coal-fired units will be the primary alternative for adding baseload capacity during the 1980s and beyond. Regulatory requirements will vary for new coal-fired units, depending on the boiler order date and whether the unit is reconverted or new. Reconversions will be required to meet SIP emissions limits. New capacity coming into service will conform to NSPS I if the units commenced construction after 1971 and before September 12, 1979. For the purposes of this analysis, it is assumed that the in-service year for NSPS I units will be prior to 1985. Units with in-service dates of 1985 and beyond will meet NSPS II requirements, including the use of scrubbers on all capacity. Again, due to construction lead-time, it is assumed that this is consistent with the EPA cutoff date for NSPS boiler orders of September 12, 1979.

Reconversions to Coal

DOE's programs to phase out oil and gas capacity are intended to carry out the National Energy Plan without sacrificing the nation's air quality. Reconversions to coal capacity from oil and gas capacity resulting from federal mandates or voluntary actions are projected to account for slightly less than 19,000 MW of coal-fired capacity during the 1980s. Though conversion entails major modifications to existing boilers, EPA and DOE have agreed that under mandatory conversion orders sources of pollution will not be required to apply for a PSD permit in attainment areas. Rather, to protect the air resource, units will be subject to the same requirements as existing plants, that is, SIP emission limits and PSD increments. Voluntary conversions may enjoy the same exemption if they were capable of burning coal before January 6, 1975.

The economic attractiveness of converting to coal rather than continuing to burn oil at any existing unit is a function of the anticipated rate of increase in the price of oil, the age of the unit, the region of the country in which it is located, the stringency of the SIP, the compliance strategy selected for the coal unit, the availability and quality of coal, the cost of necessary modifications for coal handling, and the financial condition of the utility. Prior studies demonstrated that coal-capable units with at least 10 to 15 years of remaining life are economically attractive candidates for conversion.[1] All units included in this current analysis have in-service dates in the 1950s through 1970s. Assuming that a fossil-fuel unit has a useful life of 45 years, and that at least half the conversions would be completed by 1985, units with in-service years of 1960 to 1975 would be particularly attractive candidates.

Table V-12 shows the distribution of anticipated conversions across EPA's regions. All conversions are located in the East, with the northern, mid-Atlantic and south-Atlantic states heavily represented. Regions II and IV account for about two-thirds of the capacity. EPA identified the current SO_2 emission standards for coal for these plants. For the purpose of this analysis, the standards are grouped in "low-SIP" and "high-SIP" categories, where low-SIP is below 1.66 pounds per million Btu and high-SIP is at or above that level. Specifically, low-SIP ranges from 0.4 pounds per million Btu (pounds/mmBtu) for a plant in Region II to a high of 1.2 pounds/mmBtu in Regions I and II. High-SIP ranges from a low of 1.66 pounds/mmBtu in all regions to a high of 3.34 pounds/mmBtu in Regions I and IV.

Table V-12

ESTIMATED 1980-1990 RECONVERSIONS TO COAL

	Capacity Affected (MW)[2]		
EPA Region[1]	Low SIP (<1.66 pounds/mmBtu)	High SIP (>1.66 pounds/mmBtu)	Total
I	1,372	2,573	3,945
II	897	4,181	5,078
III	0	3,339	3,339
IV	0	6,098	6,098
V	0	500	500
Total	2,269	16,691	18,960

[1]There are no anticipated conversions from oil or gas to coal in Regions VI-X.
[2]Unit capabilities after conversion.

Source: ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981; and EPA revised capacity expansion plan.

[1]G. Martin Wagner, "Substituting Coal Power Plants for Oil Plants," U.S. EPA, Energy Economics Branch, November 21, 1980. Edison Electric Institute has provided an alternative analysis of the economics of reconversion. That discussion appears in Chapter VI in this report.

Pollution control strategies for converted units are designed to respond to changes in SO_2 and TSP emissions as a result of a shift in fuels. Thermal and chemical guidelines that were part of the oil-burning environment are unchanged. Therefore, the costs of compliance to be included in a comparative analysis are air program costs--SO_2 and TSP reduction and collection costs. Two strategies are likely. A utility may choose to burn low-sulfur coal if the SIP limit allows and if there is a dependable source of fuel of appropriate quality either run-of-mine or after preparation. Alternatively, a utility may choose to install a scrubber and burn higher sulfur coal, a fuel that is cheaper and more readily available to some eastern plants.

This study analyzed the comparative air pollution control costs (including waste disposal) of reconverted and oil-fired units. It did not repeat the previous analysis of the overall economics of conversion. Table V-13 presents the results of this study. For comparative purposes, compliance costs for existing oil-fired units are shown. For the oil-fired units, the costs of compliance with air program requirements are based on those developed in the unit-category analysis for oil capacity in service before 1972.

Table V-13

1980-1990 RECONVERSIONS
AVERAGE ANNUALIZED UNIT-CATEGORY COSTS OF COMPLIANCE
AND REGIONAL EFFECTS

(1979 mills/kWh)

		Units Reconverted to Coal			
		Low-Sulfur Coal Strategy		Scrubber Strategy	
EPA Region	Oil Units[1]	mills/kWh	% difference	mills/kWh	% difference
I	12.63	5.58	-56	8.95	-29
II	9.87	5.49	-45	8.78	-11
III	10.59	5.40	-49	8.60	-19
IV	10.45	5.40	-48	8.60	-18
V	13.59	5.40	-60	8.60	-37
Average Regions I-V	10.66	5.48	-49	8.76	-18

Note: See Table VI-17 and Figure VI-6 for escalation rates for various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]Includes air pollution control costs for pre-1972 oil units and fuel premium for differential between baseline (high-sulfur) oil and high-sulfur coal prices.

Source: Energy Database and TBS calculations.

Assuming that all units choose a low-sulfur coal strategy, the capacity located in low-SIP areas will require coal with less than 1 percent sulfur and will face an average fuel premium of 4 mills per kWh. Capacity located in high-SIP areas will be able to burn coal with a sulfur content above 1 percent and will pay an average premium of 3.5 mills per kWh. In the aggregate, a low-sulfur coal strategy would cost 5.48 mills per kWh for air pollution control. However, that represents a decrease of about 50 percent when compared with the cost of the fuel differential between baseline oil and coal and of air pollution control requirements at oil-burning units.

Region II shows the smallest savings in pollution control costs for reconverted units at 45 percent, while Region V shows the largest savings at 60 percent. Region II's calculated fuel premium for pre-1972 oil-fired units is 6.05 mills per kWh, while comparable figures in Regions I and III are 8.96 and 6.83, respectively. Although all counties are in attainment for primary SO_2 and TSP, allowable emission limits in Region II SIPs range from being as stringent as surrounding regions to being markedly higher. Operating units are reporting emissions within the allowable rates, but Region II's fuel oil has a higher sulfur content on average than that burned in other regions. In contrast, Region V pays an estimated average fuel premium of 9.6 mills per kWh to meet its SO_2 limitations.

If all units choose a scrubber strategy, pollution control costs still decrease, although the savings are not as large. Overall, the pollution control cost of 8.76 mills per kWh represents a savings of 18 percent over the cost of controlling pollution from oil-fired units. Embedded in this analysis is the assumption that units located in low-SIP areas would need a scrubber with an efficiency rate of 70 percent and would pay a premium of 1 mill per kWh for better quality coal, while units in high-SIP areas would install the same scrubber but would pay no fuel premium for high-sulfur coal.

The fuel and scrubber strategies described above exclude the effects of certain costs that would, in fact, be part of the utility company's responsibility during the reconversion project. Not included are conversion costs, such as boiler modification, the purchase of replacement power during conversion, and delays in recovering the investment because of rate-setting policies. These reasons contribute to utilities' reluctance to convert their facilities. A fuller discussion of the implications of excluding certain conversion costs from the national assessment appears in Chapter VI.

New Coal-Fired Capacity: 1980-1985

In addition to the reconversions from oil to coal, an estimated 34,888 MW of coal-fired capacity will come into service during 1980-1985. The distribution of that capacity is shown in Table V-14 and is based on a survey of utility company managers conducted by ICF, Inc., for EPA. Regions I and II will increase their coal-fired capacity during the early 1980s, but only by reconverting oil-fired units that originally burned coal. Region VI will contribute approximately one-third of all new additions, with most of the growth located in Texas.

Table V-14

ESTIMATED 1980-1985 NSPS I COAL-FIRED CAPACITY ADDITIONS AND AVERAGE UNIT-CATEGORY COSTS OF COMPLIANCE

EPA Region	New Coal-Fired Capacity (MW)	Average Cost of Compliance (1979 mills/kWh)
I[1]	0	0
II[1]	0	0
III	2,557	8.1
IV	6,359	7.8
V	5,681	8.1
VI	10,989	6.5
VII	3,192	6.4
VIII	4,380	8.6
IX	1,200	5.3
X	530	5.3
All Regions[2]	34,888	7.4

Note: See Table VI-17 and Figure VI-6 for escalation rates for the various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]All Region I and II coal-fired capacity additions are accounted for by reconversions.

[2]No regional data were available for retirements; new capacity may be understated if retirements actually occur.

Source: Capacity data: ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981; and EPA revised capacity expansion plan. Cost data: Energy Database and TBS calculations.

Since the majority of areas are meeting the primary SO_2 and TSP standards, pollution control strategies at these new units will be designed primarily to meet applicable NSPS I requirements. Some units may be required to install pollution control equipment that exceeds NSPS I requirements if they are sited near Class I PSD areas or in areas with limited available increments. NSPS I requirements specify that a unit must not exceed an emission rate of 1.2 pounds of SO_2 per million Btu and must meet a TSP limit of 0.1 pounds per million Btu, which is usually achieved through installation of high-efficiency TSP control systems. Eastern coal-burning units can meet the SO_2 requirements by installing scrubbers and burning high-sulfur coal or by burning low-sulfur coal. Western units have a ready supply of low-sulfur coal that allows them to meet the standard without installing scrubbers.

Although NSPS I standards can be met without installing FGD equipment, nationwide approximately 52 percent of 1980-1985 new capacity will be scrubbed. According to the Energy Database, eastern units generally will install FGD equipment with design removal efficiency of 85 to 90 percent and will burn coal as high as 3.8 percent of sulfur. In addition, approximately one-third of the new capacity in western Regions VI and VII will use scrubbers with removal efficiencies of 70 to 80 percent and will burn coal with a sulfur content of 0.5 to 0.9 percent. Nearly all new capacity in Region VIII will be scrubbed with equipment designed to remove 80 to 95 percent of the flue gases, while burning coal with less than 0.8 percent of sulfur. (Refer to Appendix E for conversion factors to obtain sulfur contents in pounds of sulfur per ton.)

Average annualized unit-category costs of meeting environmental compliance requirements on new capacity between 1980 and 1985 include the costs of SO_2 and TSP control strategies for meeting NSPS I, as well as thermal, chemical, and solid waste control programs. As developed in Chapter IV (see Table IV-24), and based to a large extent on EPA estimates, the unit-category costs of compliance are 7.6 mills per kWh for the eastern low-sulfur coal approach, 8.6 mills per kWh for the eastern and western scrubber approach, and 5.3 mills per kWh for the western low-sulfur coal approach. (These are stated in 1979 mills for comparison with other unit-category analyses in this study.) The new capacity in each region pursues a mix of scrubber and coal quality strategies that yields a weighted-average cost of compliance, as shown in Table V-14. For example, it is assumed that all capacity in Region VIII will be scrubbed; therefore, the average cost of a scrubber strategy, at 8.6 mills per kWh, appears in the table as Region VIII's NSPS I unit-category cost. In contrast, all capacity in Regions IX and X will follow a low-sulfur coal strategy priced at 5.3 mills per kWh. In Region III, the capacity split for scrubber and eastern low-sulfur coal strategies is approximately 50-50, and the weighted-average cost of 8.1 mills per kWh reflects that mix.

A comparison of costs across regions echoes statements made by industry sources during the case study interviews that scrubbers are at least as costly as a low-sulfur fuel strategy. If the choice were based exclusively on economics, operators of nearly half the projected additions in the early 1980s would not install scrubbers. However, other factors at times dominate, including uncertainty of long-term low-sulfur coal supplies, attractive long-term high-sulfur coal contracts, or the inability to meet a particularly stringent local emission standard with readily available high-quality coal.

New Coal-Fired Capacity: 1985-1990

Although the lead time required to bring a new fossil-fueled generating unit into service may be as long as eight years, it is difficult at this time to predict the mix of fuels across all capacity and the distribution of capacity across regions for the post-1984 period. Tools that were available for 1980-1985 are not applicable here. ICF's survey for EPA included expansion plans for the near term. The Energy Database has ample data for NSPS I units, but the Form 67 did not specify submission of data beyond the 1984 planning horizon. NERC/ERA publishes a ten-year capacity expansion forecast, but the aggregate estimates may not be consistent with ICF's data. These data limitations dictate that the analysis of NSPS II compliance strategies and costs be less thorough than previous analyses.

Table V-15 shows the distribution of estimated 1985-1990 capacity additions. Trends begun in 1980 are projected to continue. Regions IV, V, and VI will continue to increase their reliance on coal-fired and nuclear capacity. In Region VI, Texas will add large coal-fired units, while Region V will retire old, small units and add large units to carry out replacement and addition strategies.

All coal-fired additions will be required to install scrubbers for SO_2 control but will have a choice of scrubber technologies. EPA assumes that eastern units can meet NSPS II requirements with scrubbers designed for 90 percent removal efficiency (wet scrubbers) and the use of eastern high-sulfur coal, or with scrubbers designed for 70 percent removal efficiency (dry scrubbers) and the use of lower-sulfur coal. The

Table V-15

ESTIMATED 1985-1990 NSPS II COAL-FIRED CAPACITY ADDITIONS AND AVERAGE UNIT-CATEGORY COSTS OF COMPLIANCE

EPA Region	New Coal-Fired Capacity (MW)	Average Cost of Compliance (1979 mills/kWh)
I[1]	0	0
II	4,349	12.4
III	2,729	12.4
IV	2,852	12.4
V	7,530	12.4
VI	12,909	9.4
VII	2,893	9.4
VIII	3,074	9.4
IX	3,877	9.4
X	340	9.4
All Regions[2]	40,553	11.5

Note: See Table VI-17 and Figure VI-6 for escalation rates for the various components of costs. An approximation to 1982 dollars can be made using the GNP escalation factor of 1.286.

[1]All Region I coal-fired capacity additions are accounted for by reconversions.

[2]No regional data were available for retirements; new capacity may be understated if retirements actually occur.

Source: Capacity data: IFC, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981; and EPA revised capacity expansion plan. Cost data: Energy Database and TBS calculations.

Energy Database contains utility submittals of planned scrubber strategies for units coming into service during 1980-1985. Of the several units that will meet the NSPS II requirements, 90 percent will use wet scrubbers and high-sulfur coal. EPA assumes that western units will use dry scrubbers because of their access to low-sulfur coal and the compatibility of that coal with dry scrubbing technology.

The compliance costs for meeting NSPS II requirements accompany the regional capacity data in Table V-15. Incorporated in these costs are the assumptions that 90 percent of eastern units will scrub high-sulfur coal and 10 percent will scrub low-sulfur coal and that all western units will scrub low-sulfur coal. It is also assumed that TSP control in the East will be accomplished with electrostatic precipitators, while western units will install baghouses. Thermal and chemical standards will be met with traditional control techniques in both eastern and western units. Based on these assumptions, the average cost of NSPS II compliance in the East is anticipated to be approximately 12.4 mills per kWh (in 1979 dollars), while western strategies carry a lower cost of 9.4 mills per kWh. Capital costs associated directly with FGD, TSP, and thermal equipment and indirectly with replacement capacity account for about 75 percent of total costs. Operation and maintenance activities carry a relatively small burden, and only in the eastern dry scrubbing approach is a fuel premium of 4 mills per kWh applied to account for higher priced fuel.

Several potential changes in the next few years would affect the approaches utilities would select for complying with NSPS II. Currently, EPA's engineering estimates of the costs of dry and wet scrubbers show that dry scrubbers with 70 percent removal efficiency are about 20 percent less expensive than wet scrubbers with 90 percent removal efficiency. However, the addition of a fuel premium causes dry scrubbers to be more expensive for controlling SO_2 emissions. Dry scrubbers have not been used successfully on eastern units burning eastern coal, although the technology has been effective when applied to western coal. That difficulty explains the trend reported in the utility Form 67 data. If and when engineering advances respond to the demand for dry scrubbers in the East, the orders for dry scrubbers may exceed those for wet scrubbers.

EPA had previously estimated that the dominant share of eastern NSPS II capacity would use dry scrubbers and would burn eastern coal containing 1.7 percent sulfur. That estimate has been revised due to technical problems, although EPA anticipates that dry scrubbing technology will be compatible with eastern low-sulfur coals in the near future. In that case, the use of dry scrubbers introduces an associated issue --the availability of eastern low-sulfur coal in quantities sufficient to meet demand created simultaneously by NSPS II requirements and rapidly expanding coal-burning capacity. The diversity of choices in compliance strategies may be constrained by coal supplies for eastern units. The longer term fuel pricing effects are difficult to predict at this time but deserve careful observation as NSPS II becomes increasingly important in the operating environment of utilities.

OTHER REGIONAL ISSUES

During the next 20 years, electric utilities will face new environmental influences that will affect their capacity expansion plans, capital costs, needs for external financing, and ultimately the amount their customers pay for the services provided. Unlike the compliance requirements of the 1970s, many of the future requirements are difficult to predict and even more difficult to quantify. However, several national issues including regional growth patterns and their effects on emissions, PSD and regional air-quality-related values, and regional siting, may have a bearing on regional compliance requirements and costs.

Regional Growth Patterns and Their Effect on Emissions

Changes in growth patterns can have a noticeable effect on air quality and on the level of control necessary to achieve and maintain the NAAQS. Yet local regulatory agencies, in the interest of attracting new growth, may be reluctant to require the ultimate in controls for proposed facilities. The Clean Air Act requires that states project growth and development in their areas and estimate the emission and air quality impacts of that growth. SIPs must then demonstrate that the NAAQS will be met or maintained by applying appropriate control measures based on growing or diminishing emissions. If industrial growth occurs at a higher than predicted rate in the Southeast or Southwest, for example, or if conversions to coal increase SO_2 emissions in the East, maintenance of NAAQS may require powerplants to meet stringent emission limitations by installing complex and costly equipment.

Other patterns of change might lead to reduced emissions. Even with increased coal-fired generation, energy conservation could limit the growth in emissions. A study of the New York metropolitan area showed that under a high-conservation approach the existing TSP exceedance would be mitigated.[2] In

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[2]GCA Technology Division and Temple, Barker & Sloane, Inc., Evaluation of Alternative Development Scenarios, New York-New Jersey-Connecticut Regional Study for the National Commission on Air Quality (NCAQ), (July 1980).

California, one of the largest utilities in the state announced plans to expand its use of renewable resources and energy conservation programs to improve the quality of the air and support national energy initiatives.

PSD and Regional Air-Quality-Related Values

An important element of the prevention of significant deterioration (PSD) program is the consideration, during evaluation of a permit application, of air-quality-related values such as visibility, odor, vitality of flora and fauna, and acidity of precipitation.

Visibility impairment takes the form of regional haze--a uniform reduction in visibility in all directions; plume blight--a clearly distinguished plume from a source; and layered discoloration--bands of discoloration observable above the surrounding land. While the relationship between SO_2 and TSP emissions and visibility is only indirect, it is known that some of the SO_2 emissions may be transformed into fine sulfate particulate matter that might degrade visibility. It is thought that emissions from coal-fired powerplants and smelters contribute more to regional haze than do any other sources of pollution, although other sources may contribute considerably.

Some evidence suggests that certain regions are harmed by acid precipitation and that emissions of SO_2 and NO_x from powerplants may be contributors. Acid precipitation is of less concern in the West than in the East. Nitric acid predominates over sulfuric acid in western precipitation; alkaline dust particles that are found in western air neutralize the acidity. In addition, western soils are relatively alkaline, creating a natural buffer in western lands and lakes to counteract the effects of acid precipitation. Finally, the large, sparsely populated western regions can absorb a large quantity of emissions and still maintain a low rate of emissions per unit area.

The East is not as fortunate. Eastern acid precipitation is two-thirds sulfuric acid and one-third nitric acid. Eastern soils and rock have high levels of acidity and poor buffering capability. The levels of acidity in the soils and lakes seem to be rising in many parts of the East and may continue to increase. The main contributors to electric utility industry SO_2 emissions in the 1990s will be powerplants that were already in service by 1976. Therefore, to the extent that utility emissions contribute to an acid problem in the East, stringent control strategies for new sources may not mitigate the problem.

The current PSD program may be largely ineffective in reversing regional air quality problems, such as visibility and acid precipitation, that are caused by pollutants that travel long distances and are the combination of emissions from several sources. Modeling cannot identify individual influences of sources of pollution hundreds of miles away, and institutional arrangements do not exist to deal with multistate problems.

Regional Siting

Selecting a site for a new facility is complex and involves consideration of many variables, including the availability of land, access to water, proximity to transportation systems and raw materials, supply of a trained labor force, favorable economic and tax climates, acceptance by the local population, environmental climate, and attractiveness of local hydrology and geology.

During the development of the Clean Air Act amendments of 1977, many states expressed concern that the existing air quality of an area not unnecessarily affect the traditional competition for growth. In response to this concern, the PSD increment program was designed with equal air quality degradation allowed in all areas that met the NAAQS and BACT technology review for all siting permit applications.

To date, PSD's influence has been less significant in interregional siting decisions than more traditional factors such as fuel and water supplies, transportation, taxes, wages, and union posture.

In the future, the PSD increment program may create interregional inequities, particularly in areas where fuel conversions from relatively clean oil or natural gas to dirtier coal consume the available increments, and in areas dominated by hilly terrain where the need for complex modeling may cause a site to be unattractive. EPA is cognizant of the potential problems in achieving national uniformity and is conducting modeling workshops as well as developing guidance documents in an effort to promote consistency in carrying out the intent of the PSD program.

Related to the issue of competition among clean air regions is the relationship between attainment and nonattainment areas and its effect on economic development. In theory, review of a major source in nonattainment areas is more stringent than in PSD areas. In practice, however, technology determinations have been similar in the two areas, especially where EPA has issued guidance documents or has promulgated NSPS. Therefore, to date PSD siting has not occurred at the expense of nonattainment areas. In the future, growth may be limited in nonattainment areas if offsets are unavailable or extremely costly, although it is difficult to quantify the potential effects on interregional growth.

CHAPTER VI

NATIONAL EFFECTS OF ENVIRONMENTAL REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

CONTENTS

VI. NATIONAL EFFECTS OF ENVIRONMENTAL REGULATIONS ON THE ELECTRIC UTILITY INDUSTRY

INTRODUCTION AND MAJOR FINDINGS

This chapter describes the financial effects of pollution control regulations on the U.S. electric utility industry as a whole. The U.S. electric utility industry is defined here to include both investor and publicly owned segments of the industry. Because of the greater availability of data on investor-owned utilities, projections for that portion of the industry are used as the basis for extrapolating to the industry level. Previous chapters have described the effects of environmental regulations at the levels of individual units, individual companies, and geographic subregions of the country. The national-level analysis of this chapter focuses primarily on the period 1980-1999. The "base case" scenario, described in detail in this chapter, reflects EPA's assumptions concerning the pollution control capital and operation and maintenance costs required to satisfy current and expected environmental regulations.

The national financial effects of pollution control regulations are estimated using TBS's Policy Testing Model of the electric utility industry, PTm(Electric Utilities). The model draws on projections of demand, capacity expansion plans, capacity utilization, and unit costs as inputs. The model then develops detailed financial and fuel use projections. PTm's financial and other results are sensitive to the input assumptions about demand growth and capacity expansion plans. To evaluate the effect of these assumptions on the estimate of total pollution control costs, alternative scenarios of demand growth and capacity expansion plans are considered. The results of the analyses of the base case and alternative scenarios are described briefly in the following pages and in more detail in the "Results of the National Analysis" section.

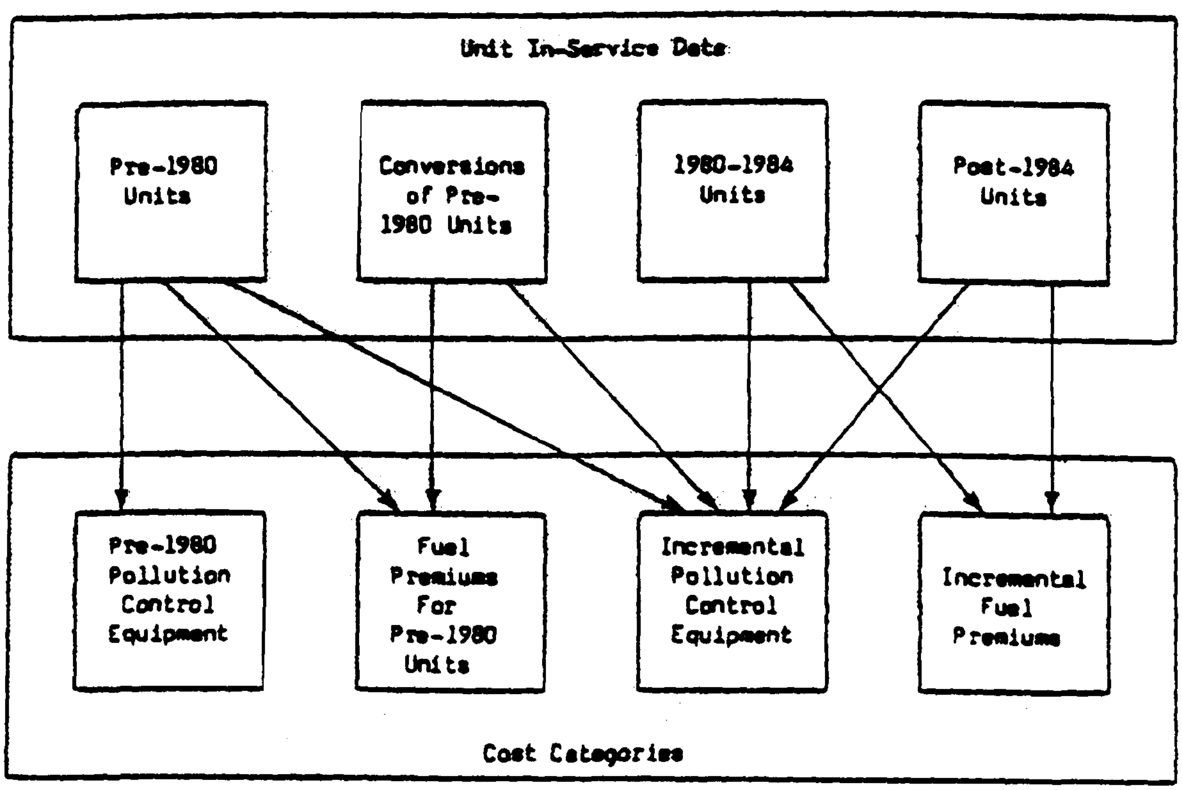
Pollution control regulatory requirements are typically related to the in-service or construction start date of a particular plant or boiler. In this analysis, costs are accounted for by unit in-service date. The year-end 1979 financial profile of the industry used for this study includes pollution control expenditures made prior to January 1, 1980. In order to determine a "baseline" projection excluding all environmental costs, these pre-1980 environmental capital costs--

which for the investor-owned portion of the industry accounted for $6.55 billion of plant in-service and $5.95 billion of construction work in progress (CWIP)--were subtracted from the December 31, 1979, financial profile. Two distinct categories of pollution control costs are then added to the baseline projection--costs associated with pollution control equipment installed prior to 1980; and pollution control expenditures for equipment installed after 1979 plus any fuel premiums incurred after 1979.

Figure VI-1 shows the mapping of unit in-service dates onto pollution control cost categories. The separation of the components of the total pollution control costs, particularly costs associated with units installed before 1980, is important for assessing the effect of specific pollution control regulations. The capital costs, and to some extent the operation and maintenance costs, associated with pre-1980 pollution control equipment cannot be altered and therefore can be considered "sunk." These historical costs are the costs analyzed

Figure VI-1

POLLUTION CONTROL COST CATEGORIES AND UNIT IN-SERVICE DATES



in detail in Chapters IV and V. In contrast, the fuel premiums associated with pre-1980 requirements and the fuel, other operation and maintenance, and capital costs of post-1979 requirements can, to a considerable degree, change depending on the shape of future regulations. The focus of this chapter is on these "incremental pollution control" costs.

Table VI-1 provides a comparison of the baseline financial projections, pre-1980 pollution control equipment costs, and incremental pollution control costs, expressed in 1982 dollars. Incremental pollution control changes in plant in-service amount to $87.3 billion over the forecast period, or approximately 8 percent of projected industry changes to plant in-service of $1,128.8 billion. Incremental external financing requirements are $70.5 billion. When pre-1980 pollution control equipment costs are included, external financing in the 1980-1999 period is reduced relative to the baseline projection by $2.3 billion. Credits for depreciation and retained earnings associated with the equipment already on the industry's balance sheets are responsible for the decline. Cumulative pollution control operating revenue requirements through 1999 are $263.3 billion, or 9 percent of the total of $2,947.5 billion, as shown in Table VI-I. Cumulative pollution control operation and maintenance expenses are $190.3 billion, slightly more than 10 percent of the total of $1,862.2 billion. Consumer charges in 1999 for pollution controls are 5.01 mills per kilowatt-hour (kWh), or 9 percent of the total of 56.16 mills.

Table VI-2 provides a breakdown of plant additions by pollutant and time period. Sulfur dioxide (SO_2) controls represent $43.3 billion or about half of all the major pollution control-related expenditures over the 1980-1999 period. Total suspended particulate (TSP) controls account for $21.9 billion or 25 percent of total pollution control-related plant additions, while water pollution and solid waste control costs represent the remaining $22.0 billion or 25 percent. Of the total of $87.3 billion of pollution control plant additions, 16 percent or $13.6 billion is attributable to capacity penalties associated with new pollution control equipment.

Table VI-1

SUMMARY OF INDUSTRY CUMULATIVE EXPENDITURES
WITH AND WITHOUT POLLUTION CONTROLS

(billions of 1982 dollars)

	1980-1985	1980-1999
Changes in Plant In-Service		
Baseline	199.17	1,041.49
Pre-1980 Pollution Control Equipment	0	0
Incremental Pollution Controls	18.45	87.28
Total	217.62	1,128.77
External Financing		
Baseline	151.78	857.63
Pre-1980 Pollution Control Equipment[1]	(1.31)	(2.28)
Incremental Pollution Controls	18.17	70.46
Total	168.64	925.81
Operating Revenues		
Baseline	594.05	2,684.23
Pre-1980 Pollution Control Equipment	13.99	45.00
Incremental Pollution Controls	44.31	218.26
Total	652.35	2,947.49
Operation and Maintenance Expenses		
Baseline	404.28	1,671.88
Pre-1980 Pollution Control Equipment	8.42	35.69
Incremental Pollution Controls	39.86	154.57
Total	452.56	1,862.17
Consumer Charges[2] (mills per kWh)		
Baseline	44.35	51.15
Pre-1980 Pollution Control Equipment	0.91	0.67
Incremental Pollution Controls	3.65	4.34
Total	48.91	56.16

[1]While there are no plant additions for pre-1980 pollution controls in the 1980-1999 period, external financing requirements are reduced because of the greater amounts of plant in-service as of 1980 for the pre-1980 equipment. This increases depreciation and retained earnings, and reduces external financing requirements.

[2]Consumer charge figures are not cumulative, but represent the annual consumer charges for the last year of the period indicated measured in mills per kilowatt-hour.

Source: PTm(Electric Utilities).

Table VI-2

CHANGES IN PLANT IN-SERVICE ATTRIBUTABLE TO POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline Changes in Plant In-Service	199.17	1,041.49
Pre-1980 Pollution Control Equipment	0	0
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	0	0
Fuel Premium[1]: Post-1979 Units	0	0
SO_2	8.91	43.32
TSP	5.68	21.94
Solid Waste	1.85	10.98
Water	2.01	11.04
Total Pollution Controls	18.45	87.28
Total	217.62	1,128.77

[1]Fuel premiums and other pre-1980 pollution controls do not have capital charges associated with them in the 1980-1999 period. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

The 1980-1999 external financing requirements associated with pollution controls amount to $68.2 billion or about 7 percent of the industry's projected total requirements (Table VI-3). The contributions to external financing requirements by pollutant correspond closely to their contribution to plant additions.

Table VI-3

EXTERNAL FINANCING EFFECTS OF
POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline External Financing	151.78	857.63
Pre-1980 Pollution Control Equipment[2]	(1.31)	(2.28)
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	0	0
Fuel Premium[1]: Post-1979 Units	0	0
SO_2	8.78	35.21
TSP	5.41	17.24
Solid Waste	1.93	9.03
Water	2.05	8.98
Total Pollution Controls	16.86	68.18
Total	168.64	925.81

[1]Fuel premiums are operating costs and do not have capital charges associated with them. The post-1979 unit category includes any coal conversions.

[2]While there are no plant additions for pre-1980 pollution controls in the 1980-1999 period, external financing is reduced because of the greater amounts of plant in-service as of 1980 for the pre-1980 equipment. This increases depreciation and retained earnings, and reduces external financing requirements.

Source: PTm(Electric Utilities).

Pollution control costs represent $263.3 billion, or approximately 9 percent of the industry's total revenue requirements during the 1980-1999 period (Table VI-4). Post-1979 SO_2 controls including all fuel premiums represent 62 percent of the total pollution control-related revenue requirements. The price premium for low-sulfur fuels alone represents the largest single component of the increase in revenue requirements--almost 40 percent. The other pollution control categories contribute less importantly to total cost increases and therefore revenue requirements. Post-1979 solid waste disposal costs, however, do rise over the period and become a significant fraction. 7 percent, of total cumulative pollution control-related revenue requirements by 1999. Water pollution control-related revenue requirements also rise over the period, representing 5 percent of cumulative pollution control requirements by 1999.

Table VI-4

OPERATING REVENUE EFFECTS OF POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline Operating Revenues	594.05	2,684.23
Pre-1980 Pollution Control Equipment	13.99	45.00
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	32.70	96.45
Fuel Premium[1]: Post-1979 Units	1.19	7.76
SO_2	5.31	59.30
TSP	2.01	22.04
Solid Waste	2.15	19.40
Water	0.95	13.31
Total Pollution Controls	58.30	263.26
Total	652.35	2,947.49

[1]Fuel premiums are typically considered SO_2 costs but are shown separately here because of their large effect on total pollution control costs. The post-1979 unit category includes any coal conversions.

Source: PIm(Electric Utilities).

Operation and maintenance expenses associated with pollution control equipment are expected to be $190.3 billion, or 10 percent of the total operation and maintenance expenses (Table VI-5). The vast majority of pollution control-related operation and maintenance expenses reflect the premium paid by utilities for low-sulfur fuels. Costs associated with the operation and maintenance of scrubbers (SO_2 controls) installed after 1979 also represent a significant portion of the total, at 14 percent. Solid waste is the only other category for which post-1979 operation and maintenance expenses are significant, accounting for approximately 6 percent of total pollution control-related operation and maintenance expenses.

Energy penalties resulting from scrubbers, TSP controls, waste disposal controls, and thermal controls installed after 1979 represent 3.4 percent of total pollution control operation and maintenance expenses, or $6.5 billion.

Table VI-5

OPERATION AND MAINTENANCE EXPENSE EFFECTS
OF POLLUTION CONTROL REGULATIONS

(billions of 1982 dollars)

	1980-1985	1980-1999
Baseline O&M Expenses	404.28	1,671.88
Pre-1980 Pollution Control Equipment	8.42	35.69
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	34.09	100.52
Fuel Premium[1]: Post-1979 Units	1.24	8.10
SO_2	2.49	26.05
TSP	0.02	3.51
Solid Waste	1.67	11.48
Water	0.35	4.94
Total Pollution Controls	48.28	190.29
Total	452.56	1,862.17

[1]Fuel premiums are typically considered SO_2 costs but are shown separately here because of their large effect on total pollution control costs. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

Consumer charges attributable to pollution control expenditures are shown in Table VI-6. The increased cost per kWh is approximately 9 percent in 1999. As is the case with other measures of the effects of pollution control, post-1979 SO_2 controls including fuel premiums represent the single largest cost category, accounting for 57 percent of the total increase in consumer charges attributable to pollution control regulations. The remaining 30 percent is split relatively evenly between costs for controls installed as of 1979, TSP controls, water pollution controls, and solid waste controls.

Table VI-6

CONSUMER CHARGE EFFECTS OF
POLLUTION CONTROL REGULATIONS

(mills per kilowatt-hour in 1982 dollars)

	1985	1999
Baseline Consumer Charges	44.35	51.15
Pre-1980 Pollution Control Equipment	0.91	0.67
Incremental Pollution Controls		
Fuel Premium[1]: Pre-1980 Units	2.12	1.00
Fuel Premium[1]: Post-1979 Units	0.13	0.17
SO_2	0.71	1.70
TSP	0.30	0.59
Solid Waste	0.26	0.49
Water	0.13	0.39
Total Pollution Controls	4.56	5.01
Total	48.91	56.16

[1]Fuel premiums are typically considered SO_2 costs but are shown separately here because of their effect on total pollution control costs. The post-1979 unit category includes any coal conversions.

Source: PTm(Electric Utilities).

As previously discussed, TBS examined two alternative scenarios in the course of this study. The summary results of that examination are presented in Figure VI-2. The changes in assumptions used to develop these scenarios are:

- Reduction in the growth rate during the 1980-1999 period from 3.0 percent to 2.0 percent, and

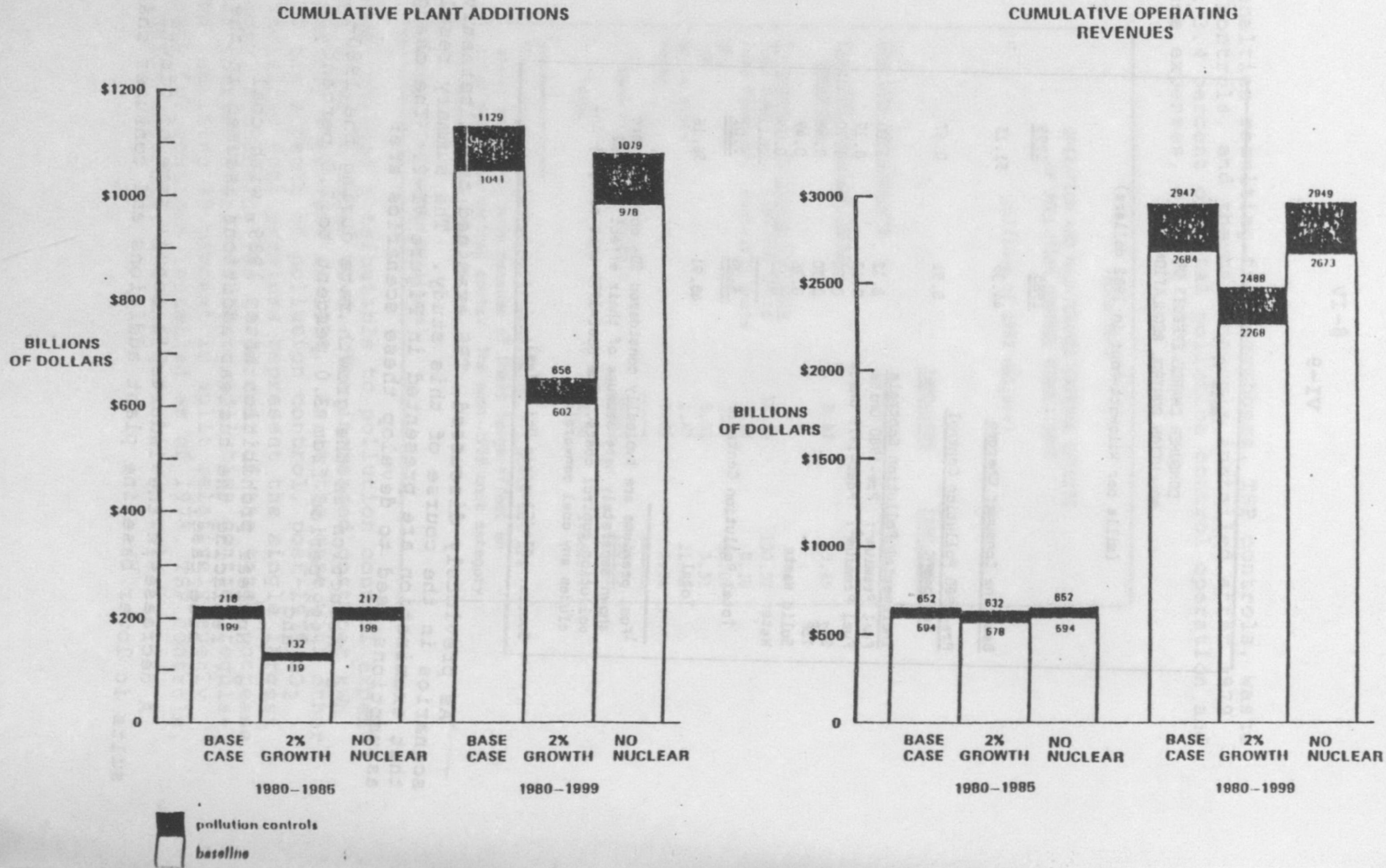
- Nuclear prohibition after 1989, with coal replacing the nuclear additions assumed in the base case.

A decrease in the industry's annual rate of growth results in lower baseline plant additions and consumer charges,

Figure VI–2

COMPARISON OF CUMULATIVE PLANT ADDITIONS AND OPERATING REVENUES UNDER ALTERNATIVE SCENARIOS

CONSTANT 1982 DOLLARS



and lower pollution control plant additions. However, the percentage increase in consumer charges due to pollution controls is essentially unchanged from the base case.

Baseline and total plant additions are slightly lower if nuclear additions are assumed to terminate after 1989. However, cumulative industry pollution control additions to plant in-service through 1999 are slightly higher ($13.81 billion) than they would be if nuclear additions were allowed to continue after 1989. Total operating revenues are virtually the same under both scenarios. Consumer charges in 1999 are also essentially unchanged under either scenario.

RESEARCH METHODOLOGY

The general approach used in the study has been first to project conditions in the industry in the absence of pollution controls (baseline case), then to project conditions with the controls and, finally, to measure the effects by contrasting one set of projections with the other. The projections are based whenever possible on published data. TBS used, to the maximum extent possible, actual operating data through 1979 and announced industry plans. Where announced plans were unavailable, which is generally the case beyond 1989, TBS reviewed various projections by industry observers and determined reasonable estimates for items such as future capacity and fuel costs. In addition, an attempt was made to use forecasts which are consistent with other recent EPA studies. In the area of pollution control costs and rates of implementation, a significant amount of original research was conducted based on data presented in FERC Form 67. The pollution control cost estimates and coverage assumptions developed from those data reflect actual experience and plans of the industry.

TBS used the model PTm(Electric Utilities) to project the financial implications of the load growth, cost, coverage, and other assumptions used in this study. PTm develops detailed year-by-year financial forecasts for the industry in both constant and current dollars. The level of detail within PTm enables a comprehensive financial analysis that includes accounting, tax, regulatory, and financial considerations. The approach, however, does not provide the capability to address supply or demand changes due to changes in costs. PTm is described in detail in Appendix B.

Five summary statistics descriptive of the detailed financial and operating projections are used to capture the major financial implications of alternative sets of assumptions. The summary statistics are:

- Changes in plant in-service,
- External financing,
- Operation and maintenance costs,
- Operating revenues, and
- Average consumer charges.

The indicators are more fully explained later in this chapter in the discussion of the baseline projections.

HISTORICAL PERSPECTIVE AND BASELINE INPUT ASSUMPTIONS

As discussed in Chapter III, until the mid-1960s the electrical utility industry enjoyed a record of steady and predictable growth accompanied by declining unit costs, relatively assured profitability, and easy access to capital. Since that time, however, the industry has witnessed a profound change in its operating, financial, and regulatory environment. The changes have encompassed almost every aspect of the utility business, including sharp changes in demand patterns, radically different relative power supply costs and options, an increasingly strained financial condition, and escalating regulatory scrutiny and requirements. These changes have markedly increased the uncertainty confronting utility decision makers and have led to a widespread concern over the most appropriate way to meet the demands and challenges now facing the industry.

The specifics of the changing utility business and regulatory environment are further discussed in the course of presenting the major input assumptions. That presentation is separated into four sections:

- Electricity demand,
- Capacity and generation profiles,

- Cost factors, and
- Financial and accounting policies and assumptions.

Electricity Demand

Future electricity demand represents, to a large extent, the starting point of the electric utility planning process. Established goals of system reliability and estimates of future demand dictate the amount of capacity additions necessary to maintain targeted reliability levels.

Two measures of electricity demand are used to describe system load characteristics--peak demand and total energy demand. Peak demand refers to the highest instantaneous rate of consumption of electricity within a specified period of time, measured in kilowatts (kW). Energy demand refers to the total amount of electricity consumed during a given time period, expressed in kWh. The levels and variability of peak and energy demand are primary determinants of the optimal amount and mix of a utility system's generating capacity.

Table VI-7 provides historical and forecast sales and peak demand. Sales are simply total energy demand minus system losses, which are assumed equal to 9 percent. The forecasts are derived from assumptions provided by EPA. As indicated by the data, there has been an abrupt shift from a high and stable pattern of growth in the 1960s and early 1970s to a lower and more volatile growth pattern in the period since the 1973-1974 Arab oil embargo.

These shifts in the patterns of growth have been brought about by dramatic changes in the underlying structure of demand. Disruptions in the historical relationships among electricity, other energy, and all other prices--and consequent changes in consumer behavior and in the availability of conservation and load management equipment--make it increasingly difficult to forecast accurately future levels of demand. As shown in Table VI-8, there has been a significant reduction in average consumption per customer over the 1960-1979 time period. This reduction represents the effect of significant conservation efforts including: reductions in thermostat settings; more energy-efficient homes, offices, and factories; and more energy-efficient appliances.

Table VI-7

HISTORICAL AND FORECAST ANNUAL GROWTH
IN PEAK DEMAND AND ENERGY SALES

Total Electric Utility Industry
1960-2005

Year	Annual Growth in Peak Demand in Kilowatts (percent)	Annual Growth in Kilowatt-Hour Sales (percent)
1961-1965 Growth Rate	7.0	4.7
1965-1966	9.2	6.9
1966-1967	5.0	9.0
1967-1968	11.5	6.5
1968-1969	8.3	8.6
1969-1970	6.6	8.7
1970-1971	6.4	6.4
1971-1972	9.3	5.4
1972-1973	7.8	7.6
1966-1973 Growth Rate	8.1	7.1
1973-1974	1.6	-0.6
1974-1975	2.2	1.5
1975-1976	4.0	6.3
1976-1977	6.9	5.1
1977-1978	3.0	3.5
1978-1979	0.9	2.9
1973-1979 Growth Rate	3.4	3.1
1979-1990[1] Growth Rate	3.0	3.0
1990-1995 Growth Rate	3.0	3.0
1995-2005 Growth Rate	3.0	3.0

[1]Based on 1979 peak demand of 409,000 megawatts and sales of 2,070.3 billion kilowatt-hours.

Source: Forecasts provided by EPA; Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1979.

Table VI-8

NUMBER OF CUSTOMERS AND AVERAGE KILOWATT-HOUR USAGE PER CUSTOMER

Total Electric Utility Industry
1960-1979

Year	Total Number of Customers[1]	Average kWh per Customer
1960-1965 Growth Rate	+2.2%	+4.7%
1966	66,910,000	15,678
1967	68,168,000	16,384
1968	69,716,000	17,445
1969	70,929,000	18,563
1970	72,485,000	19,380
1966-1970 Growth Rate	+2.0%	+5.4%
1971	74,265,000	19,956
1972	76,150,000	20,964
1973	78,461,000	21,955
1974	80,102,000	21,448
1975	81,845,000	21,417
1971-1975 Growth Rate	+2.5%	+1.8%
1976	83,613,000	22,361
1977	85,590,000	23,052
1978	87,668,000	23,315
1979	89,514,000	23,454
1976-1979 Growth Rate	+2.3%	+1.6%

[1]Includes all customer categories (e.g., residential, commercial, and industrial).

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1979.

Since 1974, many industry observers have consistently overestimated future demand, and the EPA forecast used in this study could also represent a high-side projection. However, the projection of growth of 3.0 percent per year to 1990 corresponds closely to many other industry projections; as indicated in Table VI-9, other widely circulated forecasts range from 2.8 to 4.3 percent per year. If actual demand is lower than expected, then the total baseline and pollution control costs will be below the projections of this study. The baseline and pollution control cost estimates, therefore, might be viewed as conservatively high to the extent that the forecast growth rate is at the upper end of the range of growth expectations. Of course, the cost estimates presented in this study could prove to be less than actual if growth outstrips the EPA projections.

Table VI-9

COMPARISON OF FORECAST ANNUAL GROWTH IN ELECTRICITY DEMAND

1979-1990

(percent)

Source	1979-1990 Average Annual Growth in Electricity Demand
EPA[1]	3.0
Data Resources, Inc.	2.8
Energy Information Administration	3.2
Electric Power Research Institute	3.5
Edison Electric Institute	3.2-4.3
Electrical World	4.2

[1]Projection used in this study.

Source: EPA; Data Resources, Inc., Energy Review, Winter 1980; DOE, 1979 Annual Report to Congress, Volume III (preliminary); EPRI Planning Director, reported in Electrical Week, April 20, 1981; Edison Electric Institute, Economic Growth in the Future, May 1980; Electrical World, September 15, 1980.

Sensitivity analyses showing the effect of a change in the growth rate are presented later in this chapter. The modeling approach used assumes that growth in demand is not sensitive to changing pricing conditions. The base forecast is founded on an underlying set of assumptions with respect to future electricity prices, demographic shifts, etc. This study does not attempt to model the extent to which changes in electricity prices (including those caused by pollution control expenditures) will affect consumer demands.

Capacity and Generation Profiles

The capacity and generation projections used in this study are based on the requirements implicit in the electricity demand estimates. Capacity represents the instantaneous generation capability, measured in kW, of all plants in service at a given point in time. Generation is the number of kWh produced during a given period of time. This section presents forecast changes in capacity by fuel type and the generation by fuel type required to satisfy future demand. As was the case with the demand forecasts, these data are derived primarily from information provided by EPA.

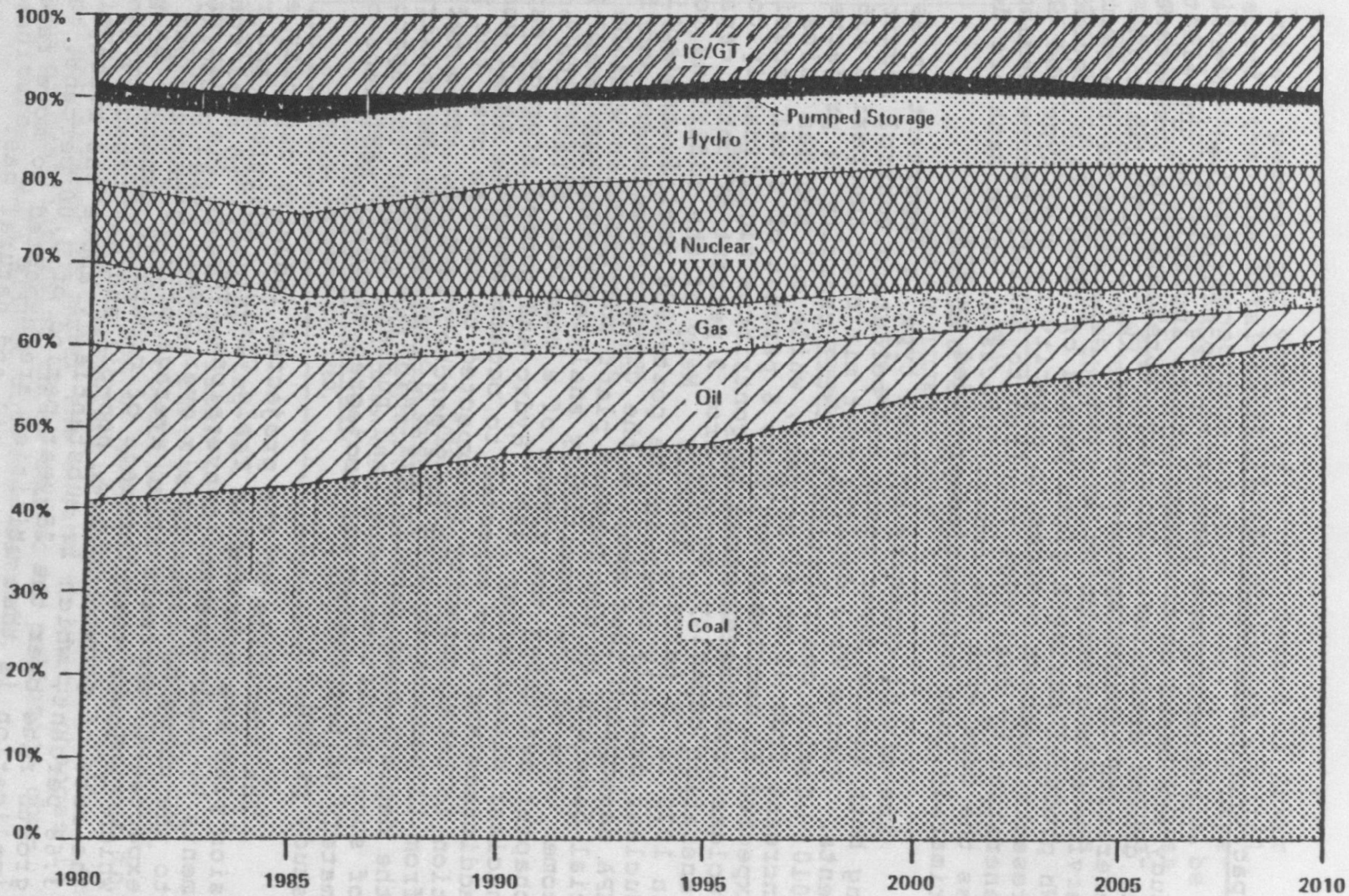
The mix of capacity by fuel type is important in estimating both future power costs and pollution control requirements. Figure VI-3 depicts that mix over the period 1980-2010. Coal's contribution to total capacity is projected to increase from 41 to 61 percent, while oil and gas units are expected to decline from 29 to 6 percent of total capacity. Nuclear power is expected to contribute significantly to new generation capacity, moving from 9 percent of total capacity in 1979 to 15 percent in 2010. Many of the additions to nuclear capacity occur in the post-1990 period, reflecting the EPA assumption that many of the current regulatory and financial barriers to new nuclear plant construction will be overcome. One of the sensitivity analyses presented later in this chapter evaluates the effect of a complete moratorium on new nuclear plants after 1989. Hydro and pumped storage capacity additions are also expected to occur; however, their contribution to total capacity is expected to decline over the period from 13 percent in 1980 to 9 percent in 2010. This reflects the depletion of readily available sites for the construction of such facilities. Coal and nuclear account for approximately 88 percent of all projected capacity additions over the study period.

The specifics of the projected industry capacity expansion plan are provided in Table VI-10. Additions and retirements by fuel type and conversions from oil to coal contribute to the changing capacity mix over time. Total capacity is expected to increase at an average of 2.72 percent per year, which is lower than the rate of growth in demand. However, the rate of growth in new, non-oil and gas capacity is 3.68 percent, which is substantially above the average demand growth rate over the 25-year period of 3.00 percent. The implication is that utilities are expected to move rapidly to reduce their dependence on oil and natural gas.

Figure VI–3

DISTRIBUTION OF GENERATING CAPACITY BY FUEL TYPE

1980–2010



Source: Forecast data provided by EPA; DOE/EIA Statistics of Privately Owned Utilities in the U.S.–1979; DOE/EIA Statistics of Publicly Owned Utilities in the U.S.–1979.

Table VI-10

U.S. ELECTRIC UTILITY CAPACITY,[1] ADDITIONS, RECONVERSIONS, AND RETIREMENTS BY FUEL TYPE

1980-2010

(megawatts)

	Coal	Oil	Gas	Nuclear	Hydro	Pumped Storage	IC/GT	Total
Capacity 1980	227,019	105,463	54,329	48,104	59,080	14,770	47,800	556,565
Additions	37,315	-	-	15,696	6,305	1,576	11,928	72,820
Reconversions	6,478	(6,851)	-	-	-	-	-	(373)
Retirements	(2,427)	(2,787)	(1,446)	-	-	-	-	(6,660)
Capacity 1985	268,385	95,825	52,883	63,800	65,385	16,346	59,728	622,352
Additions	41,429	-	-	27,884	2,330	583	3,882	76,108
Reconversions	12,482	(14,248)	-	-	-	-	-	(1,766)
Retirements	(876)	(2,119)	(1,092)	-	-	-	-	(4,087)
Capacity 1990	321,420	79,458	51,791	91,684	67,715	16,929	63,610	692,607
Additions	61,015	-	-	23,371	8,658	2,164	-	95,208
Retirements	(1,326)	(1,492)	(768)	-	-	-	-	(3,586)
Capacity 1995	381,109	77,966	51,023	115,055	76,373	19,093	63,610	784,229
Additions	114,729	-	-	22,688	6,801	1,700	4,607	150,525
Retirements	(11,393)	(8,282)	(4,267)	-	-	-	-	(23,942)
Capacity 2000	484,445	69,684	46,756	137,743	83,174	20,793	68,217	910,812
Additions	357,020	-	-	50,294	6,278	1,570	39,452	454,617
Retirements	(74,807)	(30,472)	(15,698)	-	-	-	-	(120,977)
Capacity 2010	766,658	39,212	31,058	188,037	89,452	22,363	107,669	1,244,449

[1] Capacities are for beginning of year.

Source: All forecast data provided by EPA; DOE, Statistics of Privately Owned Utilities in the United States—1979; DOE, Statistics of Publicly Owned Utilities in the United States—1979.

Table VI-11 depicts the historical and forecast reserve margins, capacity factors, and load factors. The reserve margin, a measure of the relationship between total capacity and peak demand, is currently higher than both historical and projected levels. Typically, utilities attempt to maintain reserve margins of roughly 20 percent to ensure system reliability in the face of demand uncertainty and generator "downtime" for maintenance or forced outages. The current excess reserve margin situation is due to the industry's inability to forecast the recent falloff in demand and the shifting of oil prices. Because of ten-year (or more) construction lead times, many units were and are being completed because completion is economically preferable to stopping construction already under way. Also, the rise in oil and gas prices has resulted in many units that are technically operational and are therefore included in the industry's capacity figures, but that are economically obsolete. Therefore, reserve margins are expected to decline as oil and gas units are retired and as demand catches up with existing capacity.

Table VI-11

SELECTED DEMAND, ENERGY, AND CAPACITY STATISTICS

Total Electric Utility Industry

1960-1999

Year	Capacity at Time of Summer Peak Load (MW)	1960-1979 Noncoincident Summer Peak Load[1] (MW)	Output (kWh in millions)	Reserve Margin (percent)	Capacity Factor (percent)	Load Factor (percent)
1966	240,700	203,350	1,152,900	18.4	54.7	64.7
1967	257,950	213,450	1,221,500	20.8	54.1	65.3
1968	278,950	238,000	1,327,200	17.2	54.2	63.5
1969	300,300	257,650	1,446,000	16.6	55.0	64.1
1970	326,900	274,650	1,536,400	19.0	53.7	63.9
1971	353,250	292,100	1,617,100	20.9	52.3	68.2
1972	381,700	319,150	1,752,200	19.6	52.3	62.5
1973	415,500	343,900	1,868,800	20.8	51.3	62.0
1974	444,400	349,250	1,871,700	27.2	48.1	61.2
1975	479,300	356,800	1,919,500	34.3	45.7	61.4
1976	498,750	370,900	2,039,500	34.5	46.7	62.6
1977	516,000	396,350	2,132,300	30.2	47.2	61.4
1978	545,700	408,050	2,218,700	33.7	46.4	62.1
1979	560,200	411,550	2,266,500	36.1	46.2	62.9
1985	604,600	488,400	2,716,500	23.8	51.3	63.5
1990	675,400	566,200	3,149,200	19.3	53.2	63.5
1995	769,100	656,300	3,650,700	17.2	54.2	63.5
1999	865,300	738,700	4,108,900	17.1	54.2	63.5

[1] Noncoincident summer peak load is the sum of individual utility peak demands. These demands do not have to occur during the same demand interval (e.g., peak day), but instead the total represents the sum of peak demands occurring at different days throughout the summer.

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1979; PTm(Electric Utilities).

Capacity factors are a measure of the percentage of time a unit is used. For many of the same reasons cited above, capacity factors are expected to reverse their downward trend and eventually reach levels approximating those that existed prior to the 1973-1974 oil embargo. The data in Table VI-12 clearly indicate the increasing reliance on coal and nuclear for the bulk of the country's generation needs. The relatively low 1979 nuclear utilization factor reflects in part the effects on the operations of numerous plants across the country of the nuclear plant mishap at Three Mile Island. Oil and gas capacity utilization is expected to decline dramatically because of continually rising fuel costs.

Table VI-12

PROJECTED CAPACITY UTILIZATION FACTORS BY FUEL TYPE

1979-2005

(percent)

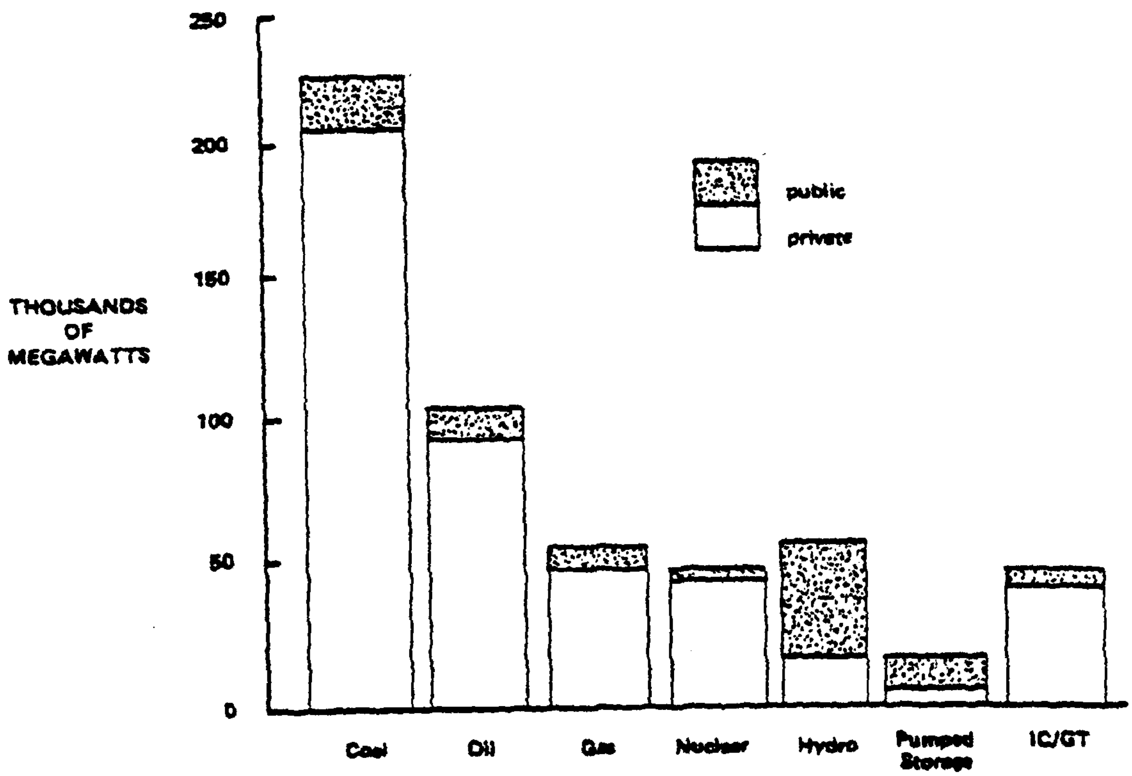
	Coal	Oil	Gas	Nuclear	Hydro	Pumped Storage	Internal Combustion/ Gas Turbine
1979	58.0	47.0	57.0	59.8	52.0	52.0	6.9
1985	61.6	42.3	42.3	70.8	48.2	48.2	6.6
1990	61.5	41.4	41.4	71.2	48.0	48.0	7.5
1995	61.5	36.7	36.7	71.3	47.8	47.8	7.6
2000	60.9	28.6	28.6	71.4	46.3	46.3	5.0
2005	59.9	24.0	24.0	71.6	45.6	45.6	5.0

Source: EPA; DOE, Gas Turbine Electric Plant Construction Cost and Annual Production Expenses—1978; DOE, Update—Nuclear Power Program Information and Data, July/August, 1980; DOE, Hydroelectric Plant Construction Cost and Annual Production Expenses—1978; TBS/EPA Energy Database.

The TBS analysis and PTm model distinguish between publicly and privately owned electric utilities because of their different financial and regulatory treatment. Therefore, Figure VI-4 provides the 1979 split of capacity by fuel type between publicly and privately owned utilities. The major difference is the much higher reliance--48 percent--on hydro and pumped storage by publicly owned utilities, compared to 6 percent for privately owned systems. Privately owned systems depend on fossil fuels for 77 percent of their total capacity, while the same figure for publicly owned systems is 39 percent.

Figure VI—4

1979 GENERATING CAPACITY
BY FUEL TYPE AND OWNERSHIP CATEGORY



Source: ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981; DOE/EIA, Statistics of Publicly Owned Utilities in the U.S.—1979; DOE/EIA, Inventory of Power Plants in the U.S.—December 1979; DOE/EIA, Hydroelectric Plant Construction Costs and Annual Production Expenses—1978.

Cost Factors

This section outlines the estimates used by TBS of the capital costs of new plant, fuel costs, and nonfuel operation and maintenance costs. These costs, combined with projected changes in the amount of utility plant, provide the information necessary to estimate changes in the industry's financial profile over time.

Unit construction costs of the electric utility industry have increased significantly in the last decade and are projected to continue to escalate more rapidly than the general rate of inflation. The causes of recent and projected construction cost increases include inflation in the cost of labor and materials, increases in the complexity of generating units, licensing delays, slippage in construction schedules, and the cost and difficulty of financing. The unit costs by plant type assumed in this study are provided in Table VI-13, both including and excluding allowances for funds used during construction (AFDC) and pollution control costs. Both are typically included in industry data. The costs reflect an in-service date of 1979 and are based primarily on data from the Technical Assessment Guide published by the Electric Power Research Institute.

Table VI-13

NEW PLANT CONSTRUCTION COSTS[1]
BY FUEL TYPE

(1982 dollars per kilowatt)

Fuel Type	Capital Cost Including AFDC[2] and Pollution Control Capital Cost	Capital Cost Excluding AFDC and Pollution Control Capital Cost
Coal[3]	1,283	903
Oil[3]	841	693
Gas[3]	533	479
Nuclear[3]	1,375	1,124
Hydro[4]	1,996	1,739
Pumped Storage[3]	947	806
Internal Combustion/ Gas Turbine	290	281
Transmission and Distribution[5]	427	383
Nuclear Fuel[6]	38	38
Coal Conversion[7]	277	96

[1]Costs are reported for a 1979 in-service year expressed in 1982 dollars.
[2]Assumes the allowance for funds used during construction (AFDC) rate of 8 percent for data derived from EPRI, otherwise the AFDC rate is based on the weighted cost of capital.
[3]EPRI, Technical Assessment Guide, July 1979. (Costs were inflated from 1978 to 1979 dollars using the Handy Whitman Index.)
[4]G. D. Marlor, Small Scale Hydro Power: Economic and Financial Analysis, BSLES-ASCE Hydro Lecture Series for 1980.
[5]DOE, Statistics of Privately Owned Utilities in the United States—1979.
[6]DOE, Update-Nuclear Power Program Information and Data, July/August 1980.
[7]TBS estimate based upon review of utility coal conversion plans for units identified by DOE as candidates for required reconversions and information provided by EPA.

Source: EPRI, Technical Assessment Guide, July 1979.

The cost of new coal capacity has been estimated by various sources at $1,025 to $1,385 per kW,[1] a range that captures the $1,283 per kW estimate used in this study. The cost of nuclear capacity has been estimated by other sources at between $1,385 and $1,449 per kW, a narrow range slightly above the cost of $1,375 per kW used in this analysis. It is probably the case that future nuclear capacity costs will increase more rapidly than those for new coal capacity.

Fuel costs represent the largest component of total operation and maintenance costs. Figure VI-5 depicts the rapid rise of fuel costs over the period 1960-1980. The impact of the 1973-1974 Arab oil embargo is clearly evident. However, the data also reflect the ongoing efforts of electric utilities to shift from oil to lower-priced fuels, primarily coal.

Current expectations are that the growth in energy prices will slow (or even decline in real terms) in the short run. However, over the entire forecast period energy prices are expected to continue to escalate. Figure VI-6 shows price projections for the major fossil fuels that are based on assumptions provided by EPA. The EPA projection assumes that the price of natural gas will rapidly converge on that of high-sulfur residual oil since they are close substitutes; in fact, in many applications natural gas is considered the superior fuel. However, because of limitations on the use of natural gas, the existence of price controls, and the current surplus situation, the price of natural gas is expected to be roughly equivalent to that of high-sulfur residual oil during the latter part of the forecast period (1985 and beyond). The price of fossil fuels includes any premiums paid for lower-sulfur-content fuel. Finally, as is evident from the figure, the price advantage of coal over other fuels is expected to grow over time. As discussed in Chapter III, the price advantage of coal--coupled with the regulatory inhibitions or prohibitions to nuclear, oil, and gas capacity--is the primary

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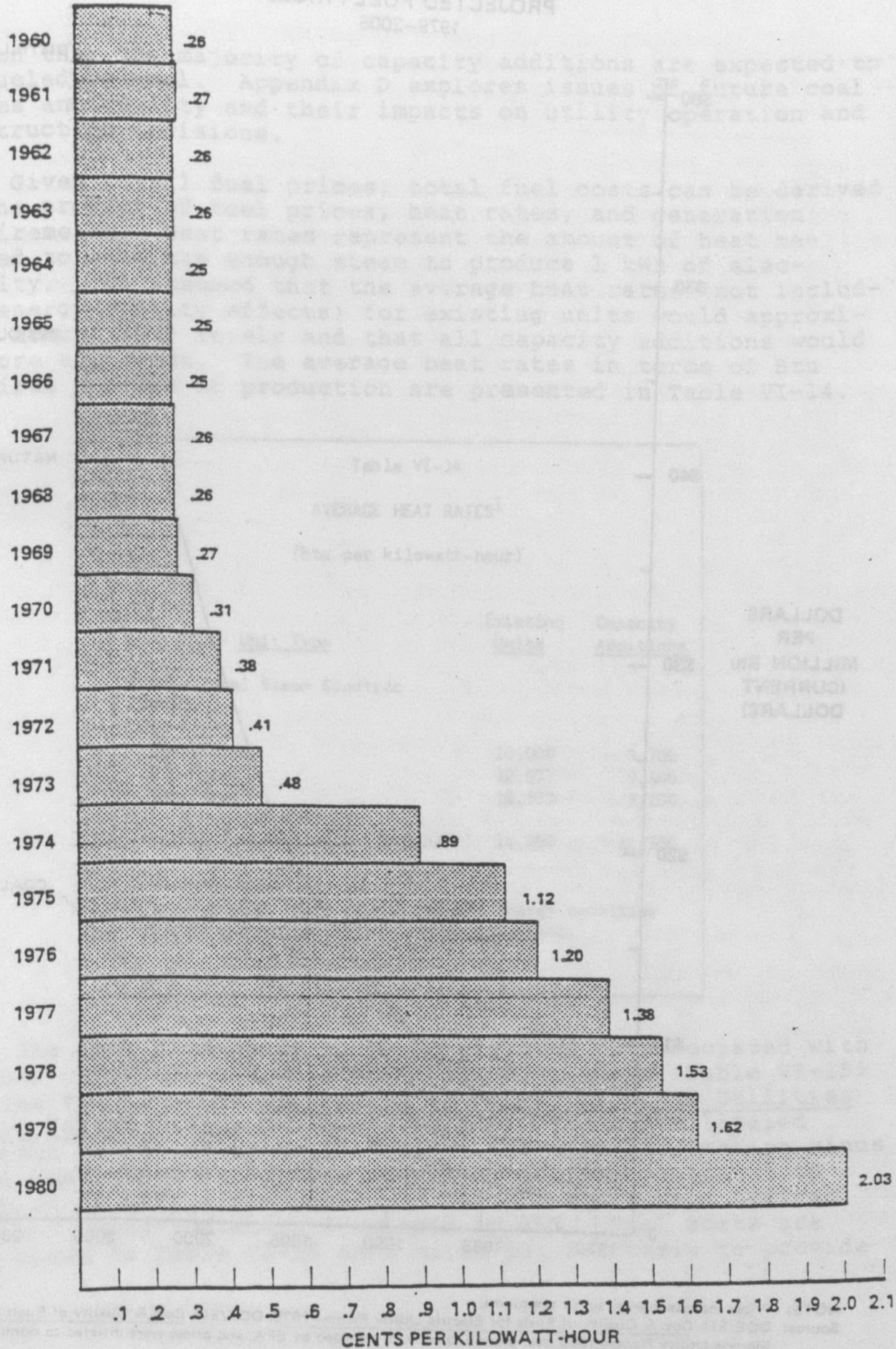
[1] Electrical World, September 15, 1979, reports the costs of coal capacity in 1979 dollars at $766 per kW and nuclear at $1,035 per kW in 1979 dollars, which translate in 1982 dollars to $1,025 and $1,385, respectively. ICF, Inc., Alternative Strategies for Reducing Utility SO_2 and NO_x Emissions, June 1981, reports capital costs (in 1979 dollars) of coal at approximately $800 per kW, which excludes the cost of a scrubber estimated at $165 per kW and nuclear at $1,083 per kW and which translates to $1,272 per kW for coal plants and $1,449 per kW for nuclear plants in 1982 dollars. Costs, however, may reflect different in-service date, pollution control, inflation rate, and AFDC rate assumptions.

Figure VI-5

AVERAGE INDUSTRY FUEL COST PER NET KILOWATT-HOUR
TOTAL ELECTRIC UTILITY INDUSTRY
1960–1980

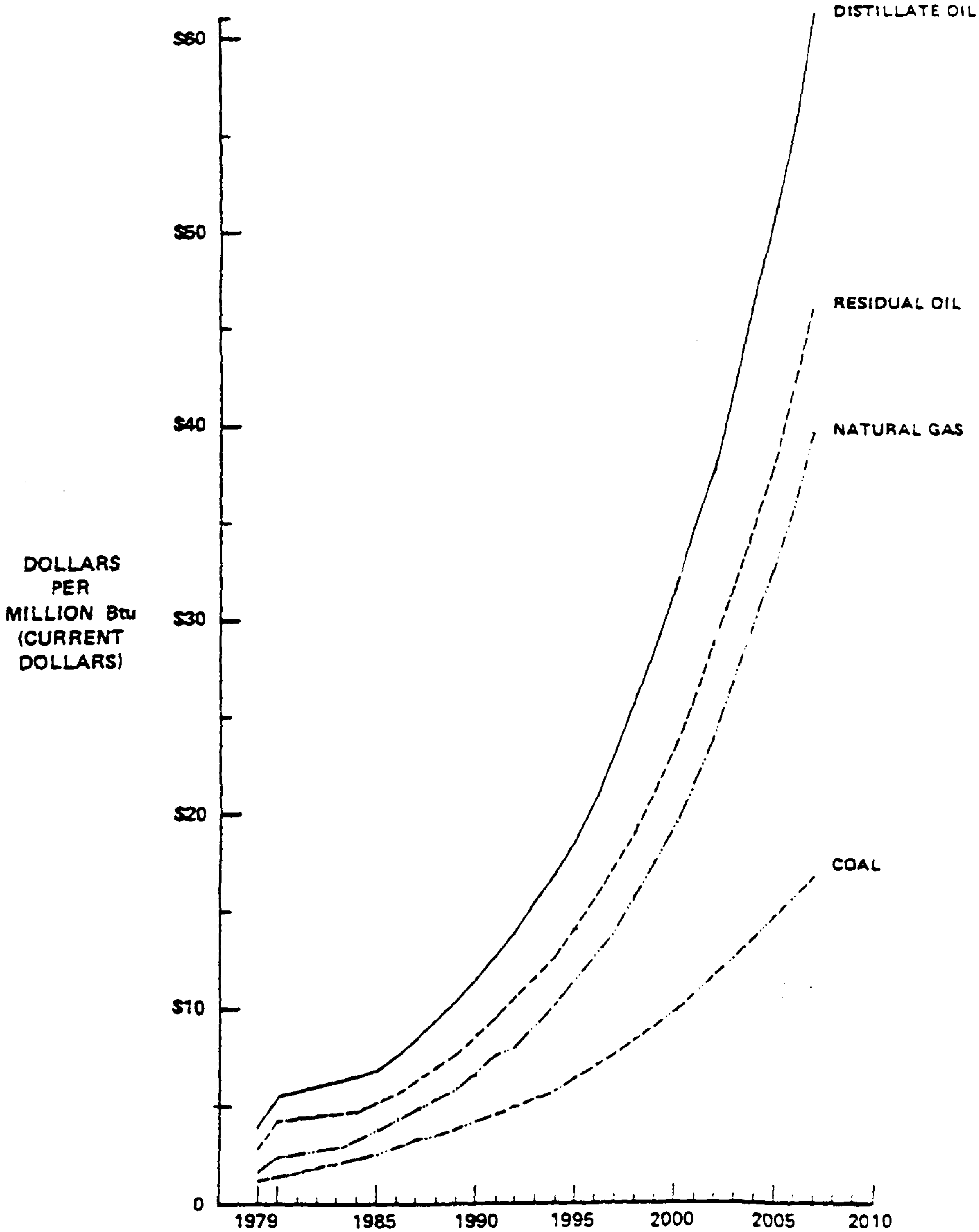


Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry (selected years).

Figure VI-6

PROJECTED FUEL PRICES

1979-2005



NOTE: Prices include average sulfur premiums.

Source: DOE/EIA Cost & Quality of Fuels for Electric Utility Plants—1979; DOE/EIA Cost & Quality of Fuels for Electric Utility Plants—1980; real growth rates were provided by EPA, and prices were inflated to nominal dollars using the TBS projected GNP deflator.

reason that the majority of capacity additions are expected to be fueled by coal. Appendix D explores issues of future coal prices and quality and their impacts on utility operation and construction decisions.

Given fossil fuel prices, total fuel costs can be derived as the product of fuel prices, heat rates, and generation requirements. Heat rates represent the amount of heat required to generate enough steam to produce 1 kWh of electricity. TBS assumed that the average heat rates (not including energy penalty effects) for existing units would approximate actual 1979 levels and that all capacity additions would be more efficient. The average heat rates in terms of Btu required per kWh of production are presented in Table VI-14.

Table VI-14

AVERAGE HEAT RATES[1]

(Btu per kilowatt-hour)

Unit Type	Existing Units	Capacity Additions
Conventional Steam Electric Units		
Coal-Fired	10,000	9,700
Oil-Fired	10,077	9,600
Gas-Fired	10,593	9,200
Internal Combustion/Gas Turbine	14,200	12,500

[1]Reported heat rates do not reflect energy penalties resulting from pollution control equipment.

Source: TBS/EPA Energy Database; EPA.

The last area of costs to be reviewed is associated with nonfuel operation and maintenance. These costs (Table VI-15) are derived from the <u>Statistics of Privately Owned Utilities in the United States</u> published by DOE. The costs labeled "without pollution control" reflect the same information minus those costs associated with pollution control equipment in place as of 1979. The pollution control costs were derived from the Energy Database developed by TBS. Fuel costs are also shown in Table VI-15 on a mills per kWh basis to provide a comparison of the relative costs by plant type. Sulfur premiums are not included in the coal and oil fuel prices; both sets of fuel prices are for high-sulfur fuels.

Table VI-15

1979 OPERATION AND MAINTENANCE EXPENSES BY FUEL TYPE: NONFUEL AND FUEL EXPENSES

(mills per kilowatt-hour in 1979 dollars)[1]

Fuel Type	Nonfuel Expenses: With Pollution Control	Nonfuel Expenses: Without Pollution Control	Fuel Expenses[2]
Coal	2.57	1.90	11.25
Oil	2.57	2.17	22.07
Gas	2.57	2.30	18.54
Nuclear	6.77[3]	6.66[3]	4.01
Hydro	2.05	2.05	N/A
Pumped Storage	2.05	2.05	N/A
Internal Combustion/ Gas Turbine	9.25	9.25	57.08
Transmission, Distribution & Other Expenses	5.03	5.03	N/A

[1]Figures can be inflated to 1982 dollars using the GNP inflator projections in Table VI-17.
[2]Does not include costs associated with a sulfur premium or energy penalty.
[3]Includes the cost of nuclear decommissioning.

N/A = Not applicable.

Source: DOE, Statistics of Privately Owned Utilities in the United States—1979; DOE, Cost and Quality of Fuels for Electric Utility Plants—1979; TBS.

Financial and Accounting Policies and Assumptions

This section briefly describes the assumptions and input data concerning financial policies and costs employed in the PTm projections. These financial assumptions are important because of the electric utility industry's capital intensity, the long lead time for construction of generating plants, the high financing costs currently in force, and the prevailing uncertainties regarding regulatory and tax treatment. The section first describes the input data used to arrive at the baseline projection and then presents selected financial assumptions that drive the financial module of PTm.

While providing essentially the same service, the public and private segments of the industry need to be treated separately because they differ significantly in their financial characteristics. In terms of generating capacity, generation. direct costs of new capacity additions, and operation and maintenance costs, the publicly owned systems account for approximately 22 percent of the U.S. total, while investor-owned systems account for the remaining 78 percent. Because the publicly owned systems have lower financing costs and tend to have a high percentage of hydroelectric generation, they account for only 12 percent of total operating revenues of the industry, while investor-owned systems account for approximately 88 percent. In terms of total assets, the public and private sectors hold about 10 percent and 90 percent shares, respectively.

TBS assumed that the 1979 ownership structure of the industry would be maintained throughout the projection period. Moreover, because there is a paucity of readily available information on the financial characteristics of those organizations in the public sector, the private sector is modeled in detail and serves as a basis for estimating certain characteristics of the public sector. The percentage distributions described above were used by TBS to extrapolate a total industry beginning balance sheet and income statement from available data for the privately owned portion of the industry. Changes to the publicly owned segment of the industry attributable to environmental regulations are modeled in the same manner as for the privately owned segment but take into account the differences in fuel type between public and private sectors.

A major input to the baseline financial projection is a set of 1979 balance sheet items, drawn primarily from the Statistics of Privately Owned Utilities in the United States, published by the Department of Energy (DOE). Table VI-16 indicates the data used, differentiated according to whether or not pollution control equipment is included. The difference reflects the effect of pollution control expenditures through 1979, which account for approximately $6.55 billion in plant in-service and approximately $5.95 billion in CWIP for the privately owned portion of the industry at the end of 1979.

Table VI-16

U.S. PRIVATELY OWNED ELECTRIC UTILITIES:
ELECTRIC PLANT LONG-TERM ASSETS AND LIABILITIES
WITH AND WITHOUT POLLUTION CONTROL EQUIPMENT[1]
AS OF DECEMBER 31, 1979

(millions of 1979 dollars)[2]

Long-Term Assets Accounts	With Pollution Control Equipment	Without Pollution Control Equipment
Gross Plant In-Service	182,514	175,966
- Accum. Depreciation	47,608	46,298
Net Plant In-Service	134,906	129,668
+ Nuclear Fuel (Net)	3,715	3,715
+ Construction Work in Progress	53,991	48,044
Net Electric Plant	192,612	181,427
Long-Term Liability Accounts		
Long-Term Debt	90,499	88,365
Preferred Stock	22,284	21,758
Owners Equity	67,741	66,144
Total Capitalization	180,524	176,267
Deferred Items	13,170	12,859
Deferred Investment Tax Credit	6,318	6,169
Total Long-Term Liabilities	200,012	195,295

[1]Includes pollution control equipment installed as of December 31, 1979.
[2]Figures can be inflated to 1982 dollars using GNP inflator projections in Table VI-17.

Source: DOE, Statistics of Privately Owned Utilities in the United States—1979; TBS/EPA Energy Database.

The projections used in this study presume a continuation of different rates of inflation for the various cost components. Those rates are provided in Table VI-17 and are derived primarily from information provided in Data Resources, Inc.'s U.S. Long-Term Review (Fall 1981). Note that the rates

Table VI-17

PROJECTED INFLATION RATES

1979-2007

Year	Annual GNP Inflation Rate[1]	Annual Utility Construction Cost Inflation Rates: Utility Plant	Pollution Control Equipment	Nuclear Fuel[2]
1979	8.5[a]	9.7[a]	6.5[a]	18.5
1980	9.0[a]	9.8[a]	6.5[a]	19.1
1981	8.7	11.1	7.3	19.9
1982	8.2	9.7	7.2	19.7
1983	8.5	10.9	7.7	19.3
1984	9.1	12.5	7.9	19.2
1985	10.0	13.5	9.1	19.4
1986	9.5	11.8	9.0	12.9
1987	8.9	9.7	8.7	12.2
1988	8.1	8.8	7.7	11.6
1989	8.1	10.9	7.3	12.0
1990	8.5	11.9	7.5	12.3
1991	8.4	10.7	7.6	9.5
1992	8.0	8.6	7.2	8.9
1993	7.4	8.4	6.5	8.4
1994	7.9	10.4	6.5	8.8
1995	8.0	10.2	6.7	8.8
1996	7.9	8.9	6.8	10.2
1997	7.3	7.8	6.4	9.7
1998	7.6	9.4	6.3	9.9
1999	7.6	9.4	6.2	9.9
2000	7.4	8.3	6.3	9.7
2001	6.9	7.1	6.0	7.7
2002	7.2	8.6	5.8	7.9
2003	7.3	8.5	5.0	7.8
2004	7.0	7.4	5.9	7.7
2005	6.4	5.8	5.7	7.8
2006	6.5	5.8	5.8	7.8
2007	6.6	5.8	5.8	7.8

[1] Used for nonfuel and pollution control operation and maintenance expenses.
[2] Forecasts of nuclear fuel price escalation rates have been reduced substantially since this forecast was prepared.
[a] Actual.

Source: Data Resources, Inc., U.S. Long Term Review, Fall 1981; Handy Whitman Index of Public Utility Construction Costs projected by TBS using data provided by Data Resources, Inc.; DOE, Preliminary 1985, 1990, 1995 Energy Forecast for Annual Report to Congress, 1980; DOE, Analysis of U.S. Nuclear Power Plant Production Costs for 1979.

of inflation applied to utility plant capital costs are above the rate of growth in GNP. Pollution control capital costs are assumed to rise more slowly than the general inflation rate, primarily because of technology change and greater operating experience. If the rate of increase in pollution control capital costs is closer to or above the rate of growth in GNP, the relative effect of pollution control equipment cost will be increased. Since pollution control expenditures represent a greater portion of total plant additions in the early periods, an increase in the general rate of inflation would increase the relative effect of pollution control plant additions.

PTm uses a number of financial indicators, ratios, and percentages in making projections. Table VI-18 provides data on 1979 actual returns and projected returns on various forms of capital. With regard to the cost of equity, TBS assumed that regulators will in the future allow average consumer charges per kWh that yield returns consistent with investors required rates of return. As discussed in Chapter III, this has not been true in the last decade. However, recent indications are that regulatory agencies are beginning to adjust allowed returns upward in response to the industry's manifest financial difficulties. The input data reflect this assumption. If returns do not increase relative to underlying rates of inflation, the industry is likely to be unwilling or unable to meet its projected external financing needs. Under such conditions, both pollution control-related and other expenditures for plant in-service will be reduced.

In projecting external financing, the model relies on inputs indicating the appropriate proportions of common equity, preferred stock, and long-term debt. Those proportions have been set for future periods at 40, 10, and 50 percent, respectively.

Internal cash generation in an industry as capital-intensive as the electric utility industry depends importantly upon the accounting procedures employed. As previously mentioned, this analysis assumes that the electric utility industry is segmented into public- and investor-owned firms. The latter group of utilities is further divided into those that are required to use flow-through accounting procedures and those that normalize their tax expenses. While alternative regulatory accounting practices significantly affect reported expenses and revenue requirements, they typically do not affect actual taxes paid.

The tax expense used by regulators in setting rates for consumers is not necessarily the same as the taxes paid by a utility. Utilities have the option, as do most companies, of

Table VI-18

FINANCIAL ASSUMPTIONS

(percent)

Capital Costs	1979	1985	1990	1995
Interest Rate, Long-Term Debt	7.6	12.6	11.3	10.3
Return on Equity	11.2	15.6	14.3	13.3
Dividend Payout Ratio	75.0	75.0	75.0	75.0
Dividend Rate, Preferred Stock	8.0	12.6	11.3	10.3
Capital Mix				
Public Sector				
Financing from Internal Sources	40.0	40.0	40.0	40.0
Private Sector				
Common Equity	37.5	40.0	40.0	40.0
Preferred Stock	12.4	10.0	10.0	10.0
Long-Term Debt	50.1	50.0	50.0	50.0
Tax Rates				
Federal Income Tax	46.0	46.0	46.0	46.0
State Income Tax	4.6	4.6	4.6	4.6
Other Taxes on Operating Revenues	7.6	7.6	7.6	7.6
Investment Tax Credit	10.0	10.0	10.0	10.0
Plant Eligible for Investment Tax Credit	66.6	66.6	66.6	66.6

Source: DOE, Statistics of Privately Owned Utilities in the United States—1979; TBS.

using either accelerated depreciation or straight-line depreciation in determining their tax liability. Over the life of an asset, the same taxes are paid regardless of which method is used. Most firms use accelerated depreciation, however, because it tends to postpone tax payments. When a utility uses accelerated depreciation to determine its tax expense and its consumers are charged for a tax expense based on straight-line depreciation, the tax benefits of accelerated depreciation are said to be "normalized." If, on the other hand, rates for consumers are based on the tax expense actually incurred by the utility, the tax benefits of accelerated depreciation are said to be "flowed through" to current consumers.

In normalized accounting, consumer rates include an amount equal to the tax rate times the difference between accelerated tax depreciation and straight-line tax depreciation. This amount is referred to as deferred income taxes and, like depreciation, represents a non-cash expense for the utility. In the early years of an asset's life when the deferred income taxes associated with the asset are positive, deferred income taxes represent, in a sense, an interest-free source of funds to the company. In the later years when the income tax deferrals associated with that asset are negative and, hence, represent a credit against the cost of service, the company in effect liquidates the funds provided by tax deferrals in the early years. However, on a companywide basis, the normalization process will always result in positive deferred income taxes during periods when a utility has increasing or constant growth in assets.

The rates of return in Table VI-18 represent the weighted average returns required by investors for various forms of capital in normalizing and flow-through utilities. In the model, however, those companies are treated separately. In the detailed analysis, it is assumed that required returns for the normalized sector average 0.5 percentage points below the returns required by investors in flow-through companies, reflecting observed capital market differences in those companies' debt and equity capital costs.

TBS's projections assume a continuation of the industry's current regulatory accounting practices. In particular, it is assumed that 30 percent of the investor-owned utilities will continue to utilize flow-through accounting, while 70 percent will use normalized accounting. For regulatory and financial accounting purposes, TBS assumes straight-line depreciation over the life of the plant. For tax purposes, depreciation figures are based on the asset depreciation range and the double-declining balance depreciation provisions within the tax code. An exception to the above is nuclear fuel, which is depreciated on a four-year, straight-line basis for both tax and regulatory purposes. In addition, a 10 percent investment tax credit is permitted on 66 percent of capitalized expenditures. These assumptions and the other tax rates are specified in Table VI-18. The financial assumptions do not reflect recent changes in the tax code that allow for more rapid depreciation of most classes of equipment.

The final area to be reviewed in this section is the timing of construction expenditures for a given capital project. This information is used to calculate CWIP and AFDC and is provided in Table VI-19.

Table VI-19

PATTERN OF CASH FLOWS FOR CAPITAL PROJECTS:
ANNUAL EXPENDITURES OF FUNDS (EXCLUDING AFDC)[1]
FOR YEARS PRIOR TO AND INCLUDING THE IN-SERVICE YEAR

(percent per year)

Capital Projects	T-6	T-5	T-4	T-3	T-2	T-1	T In-Service Year
Fossil Steam Plants	4.0	1.1	7.2	28.8	41.9	15.0	2.0
Nuclear Plants	15.0	20.0	25.0	15.0	15.0	9.0	1.0
Nuclear Fuel	-	-	-	-	25.0	25.0	50.0
Hydro Plants	9.9	13.5	17.9	18.9	23.9	11.6	4.3
Pumped Storage Plants	9.9	13.5	17.9	18.9	23.9	11.6	4.3
Internal Combustion/Gas Turbine Plants	-	-	5.0	5.0	8.7	59.0	22.3
Transmission and Distribution	-	-	-	-	-	50.0	50.0
Pollution Control Capital Equipment	-	-	-	10.0	30.0	40.0	20.0

[1]PTm limits the potential construction periods to seven years. However, slight adjustments were made to produce the appropriate amounts of construction work in progress (CWIP) and allowance for funds used during construction (AFDC) over the term of the project where lead times are expected to exceed seven years.

Source: TBS estimates based on the examination of representative utility company expenditures.

BASELINE FINANCIAL PROFILE

The baseline financial projections reflect the effect of the numerous assumptions described earlier and represent a most likely scenario of the future of the electric utility industry in the absence of any pollution control costs. Because this chapter's focus is on the effects of pollution control strategies being implemented in the post-1979 period, the capital and nonfuel operation and maintenance expenses associated with pollution control equipment in place by 1979 are, for the purpose of this analysis, treated essentially as fixed or irreversible costs. In fact, of course, the energy penalties and nonfuel operation and maintenance expenses of such equipment would be reduced, if not necessarily eliminated entirely, if it were not utilized. Moreover, that portion of capital costs associated with capacity penalties is also largely reversible.

Sales growth rates and levels of capacity are particularly critical assumptions. As discussed previously, TBS has used an annual growth rate in sales of 3.0 percent for the entire forecast period. These rates are well below the growth rates of the decade prior to 1974 and the Arab oil embargo. The capacity additions projected for the next ten years reflect the industry's effort to reduce its dependence on oil through new coal and nuclear capacity additions. Capacity additions that replace oil are expected to continue despite the current excess capacity situation. However, because of cancellations and postponements of new capacity in response to declining growth rates and financial constraints, the industry's generating capacity is projected to grow more slowly than demand through 2000.

To capture the major financial implications of alternative sets of assumptions, TBS developed statistics for the following categories: changes in plant in-service, external financing, operating revenues, operation and maintenance expenses, and average consumer charges. Table VI-20 and the discussion below summarize these financial projections. Exhibits VI-1 through VI-7, at the end of this chapter, provide financial and operating data for specific years in greater detail.

Baseline Projections

Changes in Plant In-Service are defined to be total cash outlays for plant construction during a year (both for plant that goes into service by year-end and that remains in the construction work in progress [CWIP] account), plus AFDC (the carrying charges on the past cash outlays still in CWIP), minus the year-to-year change in the cash amounts in CWIP. This definition corresponds closely to what many studies refer to as "capitalized expenditures." For a more complete discussion of the accounting methods used and the relationship between the various construction-related accounts, refer to Appendix C.

The baseline projections through 1999 indicate that changes in plant in-service will total $1,041.5 billion in constant 1982 dollars. In addition, cumulative cash outlays still in the CWIP account will increase from $60.9 billion at the end of 1979 to $191.0 billion at the end of 1999, an increase of 3.9 percent per year. The changes in the CWIP account are not included in the changes in plant in-service reported in this study. Thus, total cash outlays and the associated construction carrying costs for plant equipment during the next two decades will be $1,171.6 billion, or the sum of plant additions and the change in the CWIP account.

Table VI-20

SUMMARY OF BASELINE FINANCIAL PROJECTIONS:
BASE CASE SCENARIO

(billions of 1982 dollars)

Changes in Plant In-Service[1]	1980	1985	1990	1999
Total for Year	28.50	40.75	51.12	87.36
Total since 1979	28.50	199.17	419.47	1,041.49
External Financing				
Total for Year	10.52	31.44	38.35	82.10
Total since 1979	10.52	151.78	327.35	857.63
Operating Revenues				
Total for Year	91.13	109.64	134.46	191.26
Total since 1979	91.13	594.05	1,214.87	2,684.23
Operation and Maintenance Expenses[2]				
Total for Year	64.53	71.18	83.31	109.90
Total since 1979	64.53	404.28	794.50	1,671.88
Consumer Charges (mills/kWh)				
Average for Year	42.73	44.35	46.92	51.14

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

External Financing requirements are the sum of long-term debt, preferred stock, and common stock issues in any given year, including the refinancing of maturing long-term debt. The baseline capital market requirements during the next decade are expected to total $857.6 billion in constant 1982 dollars--approximately 82 percent of plant additions during the same period. The remaining funds required to finance the industry's expenditures for additions to plant in-service and to CWIP will be generated internally in the form of retained earnings, depreciation, and tax deferrals. If utilities are unable to earn the specified returns on equity, external financing requirements will be even higher (due to lower retained earnings) and the industry's attractiveness to potential suppliers of capital will be lower. The resulting deterioration in the industry's financial condition would make it increasingly difficult and costly to secure external financing.

One of the key financial measures which bond investors use to assess their risk exposure is pretax interest coverage. Pretax interest coverages are projected to average about 2.9 times, which is at or above the industry's recent levels. Although no significant change in pretax interest coverage is projected, it should be noted that the projected coverage ratios are highly dependent on the assumed earned return on equity, which is higher than the industry has achieved in recent years. If earnings fall short of projected levels, equity will be harder to raise and debt will be more expensive and less available than projected. Utilities which currently have low bond ratings would be particularly vulnerable to the adverse effects of lower earnings and could find it impossible to raise all of their capital needs at acceptable rates.

Operating Revenues or revenue requirements represent the total amount of money paid by utility customers for electricity in a given period. To put it another way, operating revenues are the amount required by the utilities to cover fuel, other operating, and capital-related costs. This represents perhaps the best single statistic for measuring the total effects of pollution control regulations. The baseline projections for total utility operating revenues are $2,684.2 billion in the 1980-1999 period.

Operation and Maintenance Expenses consist of all the direct costs of the operation of the electric utilities, including both fuel- and nonfuel-related expenses. Fuel represents the largest single component of these costs. One result of the rapid escalation in fuel prices since 1974 has been to increase the fuel-related share of operation and maintenance expenses to approximately 62 percent in 1979 from 50 percent prior to 1974. The TBS projection is that total baseline operation and maintenance expenses will amount to $1,671.9 billion through 1999.

Average Consumer Charges are obtained by dividing operating revenues by total sales to utility customers. Thus, this measure represents the average cost of electrical energy per kWh. This average charge is projected to increase in real terms from 42.7 mills per kWh in 1980 to 51.2 mills per kWh in 1999, a 0.6 percent compound rate of growth.

The cost of pollution controls will be measured against this base of financial results. However, before discussing those costs, it is helpful to consider briefly the financial results based on two alternative projections of additions to capacity and sales growth. They are included, in part, to illustrate how sensitive the financial indicators are to changes in the operating projections.

Alternative Scenarios

As previously discussed, the capacity expansion plan used in this study contains a significant amount of nuclear capacity additions in the post-1990 period. However, the future of nuclear power beyond the completion of currently planned facilities is quite uncertain given the rapidly escalating capital costs of nuclear plants; increasing reluctance of the investment community to support companies with nuclear construction programs; increasingly complex regulatory control; and heightened public resistance following Three Mile Island. Therefore, one of the alternative projections to be evaluated assumes no new nuclear capacity is placed in service after 1989, with coal replacing that required capacity.

The second alternative projection is based on a change in the rate of growth of electricity demand. The previous sections indicated that the study forecast was well within the range of industry projections, but that many industry analysts have consistently overestimated demand in the past five years. Therefore, a 2.0 percent growth rate in demand is assumed for the entire period in lieu of the study projection of 3.0 percent. None of the alternative scenarios or pollution control-related cost analyses presented in this study considers changes in demand in response to changes in relative prices.

The baseline financial forecasts of the two alternative scenarios are summarized in Tables VI-21 and VI-22. The comparison of plant additions, presented earlier in Figure VI-1, indicated that the 2.0 percent growth rate assumption substantially reduced the total baseline estimates. The cumulative change in plant in-service through 1999 exceeds $439 billion. External financing requirements for this scenario are negative in the first year as PTm adjusts to a substantially lower growth rate assumption. TBS assumed an instantaneous change in the capacity expansion profile; however the 1979 balance sheet reflects construction in progress. In fact, that construction would not be cancelled as rapidly as assumed for this scenario, which would smooth the trend in external financing requirements. The 2 percent growth rate scenario results in lower revenue requirements throughout the forecast period when compared to the base case scenario.

Table VI-21

SUMMARY OF BASELINE FINANCIAL PROJECTIONS:
2 PERCENT GROWTH RATE SCENARIO

(billions of 1982 dollars)

Changes in Plant In-Service[1]	1980	1985	1990	1999
Total for Year	18.82	22.69	28.60	46.30
Total since 1979	18.82	118.76	242.02	601.96
External Financing				
Total for Year	(17.69)	15.87	21.06	24.24
Total since 1979	(17.69)	53.33	146.92	409.08
Operating Revenues				
Total for Year	91.42	101.14	111.96	148.99
Total since 1979	91.42	577.83	1,112.64	2,268.03
Operation and Maintenance Expenses[2]				
Total for Year	64.07	67.90	76.78	93.26
Total since 1979	64.07	393.29	757.97	1,530.89
Consumer Charges (mills/kWh)				
Average for Year	43.29	43.38	43.49	48.43

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Table VI-22

SUMMARY OF BASELINE FINANCIAL PROJECTIONS:
NO POST-1989 NUCLEAR SCENARIO

(billions of 1982 dollars)

Changes in Plant In-Service[1]	1980	1985	1990	1999
Total for Year	28.50	40.12	45.69	81.51
Total since 1979	28.50	198.41	403.87	977.71
External Financing				
Total for Year	10.52	28.14	33.10	77.32
Total since 1979	10.52	147.24	297.32	785.83
Operating Revenues				
Total for Year	91.13	109.99	135.46	188.03
Total since 1979	91.13	594.45	1,220.99	2,672.56
Operation and Maintenance Expenses[2]				
Total for Year	64.53	71.18	83.64	113.72
Total since 1979	64.53	404.28	794.83	1,691.93
Consumer Charges (mills/kWh)				
Average for Year	42.73	44.49	47.27	50.31

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

A prohibition on new nuclear plants after 1990 also reduces future plant in-service, by approximately $63 billion through 1999, because coal plants require a much greater proportion of the total capital cost in the form of pollution controls (costs which are not included in the baseline). The reduction in plant additions in 1985 relative to the base-case scenario is an artifact of the PTm methodology for computing plant in-service. It reflects the shorter lead times and lower CWIP balances and, therefore, the lower capital-carrying charges associated with coal plants relative to nuclear plant carrying charges. In the case of the prohibition on new nuclear plants after 1989, the baseline operating revenue requirements are slighty less than in the base case scenario. However, these costs do not include pollution control equipment costs associated with the replacement coal capacity.

UNIT POLLUTION CONTROL COSTS

This section outlines the unit costs and rates of implementation associated with the various pollution control regulations. As discussed in Chapter II, the regulations vary across a number of dimensions including: federal, state, and local government requirements; the medium (air, water, or solid waste) being regulated; the timing of pollution control expenditures; and the requirements linked to a particular unit's in-service date. The discussion below details the cost and implementation assumptions, categorized according to the following unit in-service dates:

- Units existing as of December 31, 1979,
- Units reconverted from oil to coal during the period 1980-1990,
- Units coming into service during the period 1980-1984, and
- Units coming into service after 1984.

Within each of these categories, pollution control costs are presented by medium and time of implementation. No attempt is made to determine the relative effect of federal versus state and local requirements.

Units Existing as of December 31, 1979

Pollution control costs are associated with equipment existing as of 1979 for continuing capital-related charges and operating expenses and with pollution control equipment retrofits on plants placed into service as of 1979. The capital-related and operation and maintenance expenses (including fuel premiums) associated with pollution control equipment in place in 1979 are reported separately from the baseline financial projection--as pre-1980 pollution controls. Information in the Energy Database indicates that the pollution control capital expenditures for existing units averaged a total of $18 per kW over the period 1972-1979. Capital-related charges for these expenditures will continue after 1979. Continuing pollution control operation and maintenance expenses, other than fuel, average 0.67 mills per kWh of generation by fossil-steam plants. In addition, 72 percent of coal capacity incurs a low-sulfur fuel premium of 2.7 mills per kWh and all oil-fired units incur an average low-sulfur premium of 9.8 mills per kWh. Energy penalties associated with pollution control equipment average 0.23 mills per kWh and are incurred by all fossil-fired capacity constructed before 1980.

In addition to the continuing costs described above, a number of existing units will incur additional costs in the future to bring plants into compliance with air pollution control regulations. The retrofit costs described here are not included in the pre-1980 pollution control costs, but are included in the incremental pollution control costs. As shown in Table VI-23, utility Form 67 submittals indicate that 6 percent of coal capacity will retrofit scrubbers at a cost assumed to be $167.12 per kW.[2] Eight percent of coal capacity existing as of December 1979 will retrofit more efficient TSP control systems at a cost of $73.90 per kW. Units retrofitting SO_2 and TSP control systems will also incur additional solid waste disposal costs. These costs are estimated to be 1.16 and 0.64 mills per kWh, respectively, for operating costs, and $20.86 and $5.35 per kW, respectively, for capital costs.

Units Reconverted From Oil to Coal During the Period 1980-1990

A number of units that were converted from coal to oil in the late 1960s or early 1970s have incurred and will incur costs attributable to pollution control regulations. In many cases, units were originally converted to oil in the early 1970s as a means of complying with air pollution control regulations. In other cases, however, such actions occurred solely for economic reasons, e.g., because of low oil prices, the convenience of oil, or a desire for flexibility. Because economic and environmental influences could not be partitioned satisfactorily, two categories of costs, attributable in part to pollution controls, were not included in this analysis. First, none of the costs of converting plants from coal to oil

[2]Insufficient data were available in the Energy Database to determine retrofit scrubber costs. Consequently these costs were determined by applying a 1.3 retrofit factor to reported scrubber costs at new units.

Table VI-23

INCREMENTAL POLLUTION CONTROL COSTS FOR UNITS
EXISTING IN 1979 AND 1980-1990 RECONVERSIONS

(1982 dollars)

Type of Pollution Control	Capital (dollars per kW)	O&M (mills/kWh)	Energy Penalty (percent of generation)	Affected Plants
Scrubbers[1]	167.12	2.83	3.9	6% of 1979 existing coal capacity (45.5% of reconversions)
TSP Control	73.90	N/A[2]	0	8% of 1979 existing coal capacity (all reconversions)
Scrubber Waste Disposal	20.86	1.16	0	Same as scrubbers
TSP Waste Control	5.35	0.64	0	Same as TSP Control
Low-Sulfur Fuel Premium				
Coal	0	2.74[3]	0	72% of 1979 existing coal capacity plus 54.5% of reconversions
Oil	0	9.77[3]	0	All oil capacity
Gas	0	0	0	
Thermal Control	N/A	N/A	N/A	
Chemical Control	N/A	N/A	N/A	

[1]In addition to the scrubber capital cost, a capacity penalty of 3 percent is incurred by units with scrubbers.
[2]Included as TSP waste disposal.
[3]Weighted average for all plants from the unit level analysis.

N/A = Not applicable.

Source: TBS/EPA Energy Database.

in the past, or of reconverting back to coal are included as pollution control costs. Second, none of the costs of oil consumption in plants that, in the absence of environmental regulations, would have burned coal are captured in this study's definition of pollution control costs.

Regarding conversion and reconversion costs, one industry study sponsored by Edison Electric Institute (EEI) assumed that approximately 37,000 megawatts (MW) of the capacity that once burned (or has the capacity to burn) coal converted to oil because of environmental regulations. EPA agrees that conversions, at least during the 1970s, occurred in part because of environmental regulations. Circumstantial evidence supporting that opinion can be cited; a DOE profile of reconversion candidates showed that conversions to oil took place largely during the late 1960s and early 1970s, at the same time that states and the federal government were moving toward greater stringency in emissions allowances. For example, of 76 candidates for reconversion, 45--nearly 60 percent--converted between 1969 and 1972.,

To assess the importance of economic factors, one would also need comparisons of the delivered costs and the operation and maintenance expenses associated with the high-sulfur coal and high-sulfur oil that utilities would have been using as a basis for decision making in the absence of environmental regulations. Given the drastic change in oil prices at the end of 1973, it can safely be assumed that most of the 1974-1980 coal-to-oil conversions were dictated by environmental concerns. However, many of the pre-1974 conversions may have occurred for purely economic reasons. In sum, it remains unclear what portion of the costs associated with coal-to-oil conversions and reconversions is attributable to federal (or state) environmental regulations. Thus, even for the 19,000 MW of capacity that EPA assumes will reconvert to coal, it is unclear what portion of the reconversion costs are attributable to environmental regulations.

In addition to conversion and reconversion costs, a number of units in this time period were constructed with multi-fuel capabilities. This design feature is, in part, a response to environmental regulations and provides the utility with the flexibility to adapt to changing regulations and pollution control technologies. A portion of these incremental costs of attaining this flexibility should be attributed to pollution control regulations. This study does not include such costs in the total costs attributable to pollution control regulations.

The industry study further argued that, in addition to the 19,000 MW that EPA assumes will reconvert, all (or most) of the remaining 18,000 MW would already have converted (or would convert) back to coal if there were no environmental regulations. Accordingly, the EEI study contends that it is environmental requirements that dictate continued oil burning in 18,000 MW of capacity. Again, there is circumstantial evidence in support of this assertion.

The DOE profile cited above also contains data provided by utilities regarding environmental and other impediments to reconversion:

Reconversion Constraints	Number of Stations[1]
Lack of trained personnel	6
Lack of low-sulfur coal supply	1
Space constraints for coal and ash storage	20
Lack of coal-handling equipment	9
Requirement for crane, crusher, pulverizer, etc.	5
Requirement for desulfurization equipment	9
Lack of emissions waivers	5
Requirement for wastewater treatment	2
Lack of ash disposal site	8
Noise abatement rules	2
Unspecified environmental issues	8
Financial constraints	5

[1]Many stations indicated more than one constraint.

This list contains a number of non-environmental impediments that may be decisive for a substantial portion of the total universe of coal reconversion candidates. Thus, even assuming that all the original coal-to-oil conversions were for environmental reasons, one cannot assume that all the costs associated with the continued burning of oil are attributable to environmental regulations. The sulfur premiums associated with the continued burning of low-sulfur oil--which costs are included in this EPA final report--are, of course, essentially all attributable to state or federal environmental regulations.

In determining the costs of environmental compliance, the industry study included in its baseline as coal-fired capacity 10,400 MW that was actually built as oil rather than coal and 37,000 MW of converted coal-capable oil-fired capacity that may not have converted to oil in the absence of environmental regulations. Environmental compliance costs were then computed at those units as the difference between coal-fired generation without environmental controls and oil-fired generation with environmental controls.

EPA's analytical approach was different. Because of the uncertainties in alternative assumptions such as baseline fuel costs, compliance oil costs, capacity utilization, and the type and timing of new capacity additions, EPA included the 47,400 MW of existing oil-fired capacity in the PTm(Electric Utilities) baseline and calculated compliance costs as the increase over baseline oil-fired generation costs caused by environmental regulations. Those costs are dominated by the premium for low-sulfur oil. In this analysis it accounts for approximately 90 percent of the 1980 costs of compliance for oil units and is projected to increase. However, this approach produces impacts that are smaller than an approach that assumes that some or all of those units would be coal-fired in the absence of regulations.

The differences between the EPA and the industry approaches are substantial. Presuming no switch in fuel type, compliance costs of units complying with pollution control regulation are approximately 20 percent and 15 percent, respectively, above baseline generation costs. However, the cost of operating a <u>complying</u> oil-fired unit is estimated to be about 85 percent more than operating a <u>noncomplying</u> coal-fired unit.

It is difficult to establish an approach that correctly captures environmentally related costs of constructing, converting, or reconverting utility units. Many studies have adopted a subjective approach to the attribution of costs that overlooks the real economic pressures for building oil-fired units, for converting coal units to oil, or for not reconverting to coal. On the other hand, the EPA approach used in this study certainly fails to capture all the costs associated with environmental compliance. Figure VI-7 demonstrates the many issues and decision points associated with allocating generation capacity decisions to environmental or economic reasons.

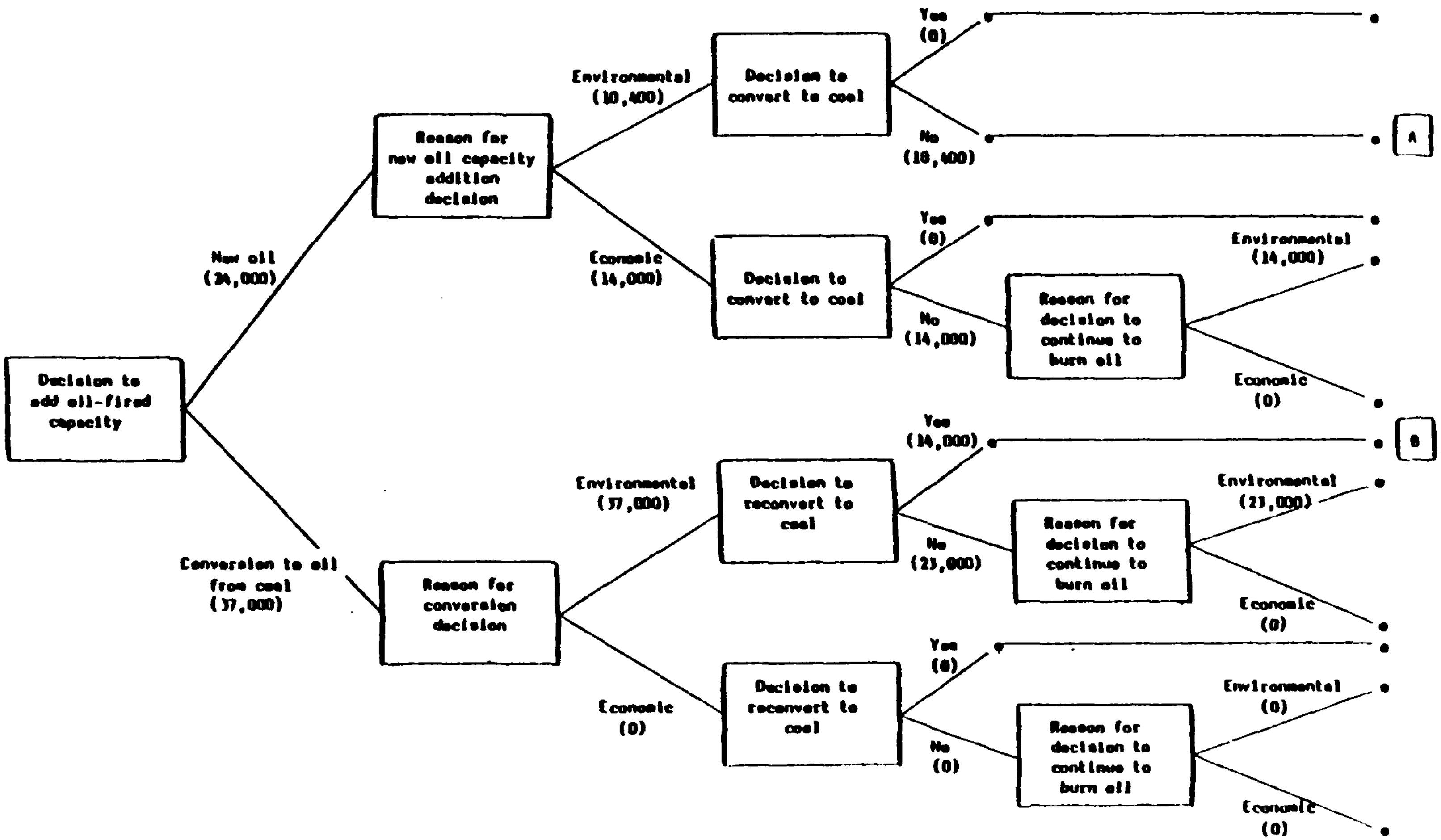
The decision tree in Figure VI-7 begins with the decision to add oil-fired generating capacity. These capacity additions were either new oil-fired units or units converted from coal to oil. For each category, the decision to add oil-fired capacity can be classified as a decision driven by either environmental or economic reasons. In each case there are environmental costs associated with the capacity additions; however, the magnitude of costs varies greatly.

With the dramatic changes in fuel prices in the 1970s, utilities were then confronted with the decision of whether to convert these oil-fired units or to reconvert them to coal. The attribution of the cost differentials between oil- and coal-fired units, the costs of conversions and reconversions, and the costs of pollution control equipment to pollution control regulations depends on the original reason for adding the oil-fired unit and the subsequent reason for either converting (or reconverting) to coal or continuing to burn oil. Two end-points of the decision tree, labeled "A" and "B", have

Figure VI-7

ATTRIBUTION OF THE COSTS OF INCREASED OIL CONSUMPTION, CONVERSION TO OIL, AND RECONVERSION TO COAL SINCE 1965 TO ECONOMIC OR ENVIRONMENTAL DECISION

(numbers in parentheses indicate EEI's estimated capacity in megawatts[1])



[1]Based on information provided in ICF, Inc., The Economic and Financial Impacts of Environmental Regulations on the Electric Utility Industry, prepared for the Edison Electric Institute, February 1980.

been chosen to illustrate the pollution control costs associated with those particular sets of decisions.

End-point "A" of the decision tree represents a new oil-fired unit designed for oil burning because of environmental reasons, and an oil-fired unit that has continued to burn oil (rather than converting to coal). The environmental costs associated with this type of unit include the capital and operation and maintenance cost differential between coal- and oil-fired units (negative), plus the fuel price differential between high-sulfur coal and low-sulfur oil, plus any pollution control equipment costs associated with oil-fired units. In short, the pollution control cost is the difference between the annualized cost of an uncontrolled coal unit and a controlled oil unit.

End-point "B" of the decision tree represents a unit that was converted from coal to oil for environmental reasons and was subsequently reconverted to coal. The pollution control costs for such a unit include reconversion costs, plus the coal fuel premium, plus any pollution control equipment costs. In addition, there are the costs that were incurred during the period the unit burned oil. These costs include the fuel cost differential between high-sulfur coal and low-sulfur oil, minus the operation and maintenance cost differential between coal and oil units, plus the conversion costs, plus any pollution control equipment costs. In general, the pollution control costs for such a unit include direct pollution control costs associated with coal units, plus conversion and reconversion costs, plus the cost differential of operating an uncontrolled coal-fired unit versus a controlled oil-fired unit during the period the unit burned oil.

The decision tree highlights the difficulties and issues involved in allocating costs to pollution control regulations. The numbers in parentheses indicate the allocation of megawatts of capacity implicit in a recent study conducted for EEI.[3] This particular allocation attributes a large share of the difference in constructing and operating coal- versus oil-fired units to the total costs of pollution control-related decisions. On the other hand, this study understates the pollution control-related costs associated with the conversion and reconversion of utility generating capacity. The appropriate allocation lies somewhere between the two estimates.

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[3]ICF, Inc., <u>The Economic and Financial Impacts of Environmental Regulations on the Electric Utility Industry: Draft Final Report</u>, prepared for Edison Electric Institute, February 1980.

In the future, units converting to coal will be required to upgrade air pollution control equipment to meet environmental standards, but are expected to comply with chemical and thermal discharge guidelines with existing equipment. Costs for these units are listed in Table VI-23. EPA provided TBS with the basic assumption that 45.5 percent of units reconverting from oil to coal will install scrubbers. These costs are assumed to be equivalent to the retrofit scrubber costs reported for coal units in the Energy Database. The remaining units that do not retrofit scrubbers are assumed to incur a fuel premium equal to that paid by 1980-1984 units that are required to meet new source performance standard (NSPS I) limits. All reconverting units are also assumed to upgrade TSP controls at a retrofit cost of $73.90 per kW since TSP control systems on oil-fired units are less extensive than those on coal-fired units.

Units Coming Into Service During the Period 1980-1984

Units coming into service in 1980-1984 are required to comply with air pollution limitations established by NSPS I, as discussed in Chapter II. Cost and coverage assumptions for these units, shown in Table VI-24, are derived from the Energy Database and are used to estimate control costs for 1980-1984 capacity. New coal units will comply with air, water, and solid waste regulations and new nuclear units will be affected only by water regulations. There is no new oil or gas capacity expected to come into service after 1980. Analysis of the Energy Database indicates that 52 percent of coal capacity coming into service in the 1980-1984 period will comply with NSPS I limitations on SO_2 emissions--1.2 pounds per million Btu--by installing scrubbers at an average cost of $128.55 per kW. In addition, 44 percent of 1980-1984 capacity will incur a low-sulfur coal premium. Some units will burn coal with less than a 0.8 percent sulfur content, while others will burn coal with a medium sulfur content and also use scrubbers. The fuel premium applied to these units (3.06 mills per kWh) is based on the average fuel premium paid by similar units that came into service during the 1977-1979 period and are subject to NSPS I regulations.

Particulate limits under NSPS I require the use of high-efficiency scrubbers at all coal plants coming into service during the 1980-1984 period. TBS used an average TSP control system cost of $47.52 per kW derived from the Database. This cost is applied to all 1980-1984 coal capacity.

Table VI-24

WEIGHTED AVERAGE POLLUTION CONTROL COSTS[1] FOR UNITS COMING INTO SERVICE DURING 1980-1984

(1982 dollars)

Type of Pollution Control	Capital (dollars per kWh)	O&M (mills/kWh)	Capacity Penalty (percent of capacity)	Energy Penalty (percent of generation)	Affected Plants
Scrubbers	128.55	2.83	1.95	1.95	52% of 1980-1984 capacity
TSP Control	47.52	-	0.50	0	All 1980-1984 capacity
Scrubber Waste Disposal	20.86	1.16	0	0	Same as scrubbers
TSP Waste Control	5.35	0.64	0	0	Same as TSP
Low-Sulfur Fuel					
Premium					
Coal	0	3.06	0	0	44% of new coal capacity[2]
Oil	0	-	0	0	
Gas	0	-	0	0	
Thermal Control					
Fossil	13.63	0.30	1.65	0.65	60% of new capacity
Nuclear	10.71	0.42	3.05	2.05	33.83% of new capacity
Chemical Control					
Fossil	7.50	0.09	0	0	All new capacity
Nuclear	1.29	0.00	0	0	All new capacity

[1] Costs are weighted by the amount of capacity using specific types of equipment (e.g., high- and low-efficiency scrubbers). Discussion of equipment-specific costs can be found in Chapter IV.
[2] Includes units burning low-sulfur coal without scrubbing and units burning low-sulfur coal with scrubbing.

Source: TBS/EPA Energy Database; EEI (non-capital thermal costs and chemical costs).

The magnitude of the costs of complying with solid waste regulations depends significantly on whether units have SO_2 scrubbers. Units in the Database that do not have scrubbers and therefore dispose only of fly ash and bottom ash incur an average capital cost of $5.35 per kW and annual operation and maintenance expenditures of 0.64 mills per kWh. Costs for combined ash and scrubber sludge disposal facilities are nearly four times the cost for ash disposal facilities alone. This difference results from the greater volumes of ash and sludge requiring disposal and the need, in most cases, to construct a lined pond for ash-sludge co-disposal. Lined ponds are not typically required for ash disposal without sludge disposal.

Chemical and thermal pollution control expenditures apply to both coal and nuclear capacity. The cost of cooling towers for fossil plants is based on Energy Database information for 1977-1979 units (cooling tower data are not reported for future units). Nuclear plant cooling tower costs are based on costs used in EPA's 1974 Economic Analysis of Effluent Guidelines, Steam-Electric Powerplants (Economic Analysis) that assumed installation of cooling towers. Operation and maintenance costs and capacity and energy penalties for both coal and nuclear units are those established during joint review of the draft version of this report with EPA, TBS, EEI, and ICF.

Regulations requiring cooling towers on all new sources were remanded in 1977, and cooling tower requirements are currently left up to the "best engineering judgment" of permit writers on a case-by-case basis. For this reason the extent of use of cooling towers on future units is somewhat uncertain. To establish a coverage for future cooling towers, TBS examined the extent of use of cooling systems on recent fossil units in the Energy Database and recent nuclear units in the Generating Unit Reference File (GURF) database, and projected these coverages to future units. As noted in Chapter IV, cooling towers in water-constrained regions are frequently installed in response to economic rather than environmental requirements. To the extent that cooling towers are installed for economic reasons, this analysis overstates the cost of cooling towers associated with environmental compliance.

EPA is currently revising its chemical effluent limitations guidelines and, therefore, considerable uncertainty remains concerning these guidelines. The costs used in this analysis are costs of compliance with guidelines currently in effect--essentially the best practicable control technology (BPT) standards established in 1974. The costs of complying with chemical guidelines for both coal and nuclear units are not reported in the Energy Database and are based instead on the results of a joint review with EPA, TBS, and EEI.

Units Coming Into Service After 1984

Cost and coverage assumptions for post-1984 units were provided by EPA on the basis of past studies and engineering cost estimates. These costs provided by EPA are shown in Exhibit VI-8. Table VI-25 indicates the weighted average of the costs shown in Exhibit VI-8. Data in the Energy Database do not provide projections beyond 1984 and consequently those data were used only to validate assumptions provided by EPA.

Table VI-25

WEIGHTED AVERAGE POLLUTION CONTROL COSTS[1] FOR UNITS COMING INTO SERVICE AFTER 1984: BASE CASE SCENARIO

(1982 dollars)

Type of Pollution Control	Capital (dollars per kWh)	O&M (mills/kWh)	Capacity Penalty (percent of capacity)	Energy Penalty (percent of generation)	Affected Plants
Scrubber					
Eastern	123.08	1.75	2.02	1.58	63% new coal
Western	90.13	1.32	0.79	1.81	37% new coal
TSP Control					
Eastern	45.59	0.26	0.28	0.28	63% new coal
Western	69.65	0.66	0.81	0.81	37% new coal
Waste Disposal					
Eastern	50.84	0.39	0.03	0.03	63% new coal
Western	8.24	0.46	0	0	37% new coal
Low-Sulfur Fuel					
Premium	0	3.06	0	0	6% new coal
Thermal Control					
Fossil	13.63	0.30	1.65	0.65	60% new capacity
Nuclear	10.71	0.42	3.05	2.05	39% new capacity
Chemical Control					
Fossil	7.50	0.09	0	0	All new capacity
Nuclear/Gas	1.29	0	0	0	All new capacity

[1]Costs are weighted by the amount of capacity using specific types of equipment (e.g., high- and low-efficiency scrubbers). Discussions of equipment-specific costs can be found in Chapter IV.

Source: TBS/EPA Energy Database (fuel premium, thermal control capital); General Utility Reference File (GURF) (nuclear coverage); EEI (thermal noncapital costs and chemical costs); EPA (other costs).

Units coming into service after 1984 are assumed to comply with NSPS II air regulations, disposal facility guidelines under Resource Conservation and Recovery Act (RCRA section 4004--nonhazardous waste disposal), and current water regulations. Costs of compliance and coverage assumptions concerning water regulations are the same for those units as for units that will come into service in 1980-1984.

Emission limitations under NSPS II air regulations require new units to meet an emissions rate between 0.6 and 1.2 pounds with an SO_2 removal rate of 90 percent. Those plants able to attain an emissions rate below 6 must still remove at least 70 percent of the SO_2 in their coal. In addition, new units are required to install high-efficiency TSP control systems and nitrogen oxide (NO_x) controls based on combustion modifications. Some units siting in the vicinity of Class I prevention of significant deterioration (PSD) areas, or PSD areas where increments are nearly exhausted, may be required to meet best available control technology (BACT) standards that are more restrictive than NSPS II. Solid waste guidelines under RCRA section 4004 will require lining of disposal facilities as well as special precautions for facilities locating in flood plains.

The assumed weighted average control costs for the base case scenario, shown in Table VI-25, are based on the following assumptions provided by EPA:

- In the West, 81 percent of new units will install scrubbers with 70 percent removal efficiency and will burn low-sulfur western coal, while the remaining 19 percent will install equipment that will achieve more stringent BACT requirements of 90 percent removal efficiency on similar-quality coal.

- In the East, 90 percent of new capacity will choose to burn high-sulfur coal and install scrubbers with 90 percent removal efficiencies.

- A relatively inexpensive dry scrubbing technology that can be used to obtain 70 percent removal efficiencies on low-sulfur eastern coal will not be available widely, and will be the selected strategy at only about 10 percent of eastern capacity installed after 1984. Sufficient quantities of coal with an SO_2 content of 2.8 pounds per million Btu (approximately 1.7 percent sulfur by weight), will be available to supply 10 percent of capacity additions in the East.

EPA estimates that wet scrubbing and 90 percent removal will cost $127 per kW, while dry scrubbing technologies with removal rates of 70 percent will become available in the East at approximately $84 per kW by 1985. As noted in Chapter IV, the difference in cost between wet scrubbing at 90 percent removal efficiencies and dry scrubbing at 70 percent removal efficiencies is important in determining the utility decision between high-sulfur coal strategy and a low-sulfur coal strategy. These two strategies represent the extreme ends of a spectrum of possible combinations. The choices presented here, then, represent two potential combinations of removal efficiency and sulfur content. Other combinations may, in fact, be selected and may be economically desirable. In this analysis, dry scrubbing with a removal rate of 70 percent using low-sulfur coal is slightly more attractive economically, but is selected by only 10 percent of post-1984 units in the East because the technology is still in its early stages.

Only 10 percent of new eastern capacity is assumed to use low-sulfur coal with its associated fuel premium. The premium is assumed to remain constant in real terms at 3.06 mills per kWh. Western units do not incur a low-sulfur coal premium.

Solid waste disposal costs differ between the scrubber technologies for two reasons. The higher sulfur contents and the higher removal efficiencies implicit in the high-sulfur coal scrubbing approach result in approximately six times as much scrubber sludge requiring disposal as in the low-sulfur coal approach. A second important consideration is that the scrubber sludge resulting from a wet scrubbing process is more difficult to dispose of than residues from dry scrubbing. For example, the capital cost for sludge and ash co-disposal for a unit with 90 percent wet scrubbing is $56 per kW, compared with about $4 per kW at a plant with 70 percent dry scrubbing. Table VI-25 shows the weighted average of these costs.

Particulate matter control costs are lower under the high-sulfur scrubbing approach. Assumptions provided by EPA indicate that low-sulfur coal units with dry scrubbers will choose to install baghouses to control TSP--at a cost of approximately $69 per kW. The cost of electrostatic precipitators used by units that burn high-sulfur coal is $43 per kW--$26 per kW lower. Consequently, the lower cost of TSP control associated with high-sulfur scrubbing partially compensates for the higher cost of the scrubber itself.

RESULTS OF THE NATIONAL ANALYSIS

This section presents the TBS estimates of the national costs of pollution control regulations for the period 1980-1999. The costs associated with the base case scenario, described in the initial section of this chapter, are presented first, arrayed along a number of dimensions. Next, two alternative scenarios are evaluated to determine the effect of particular input assumptions on total pollution control costs. All of the scenarios use a starting financial profile which excludes all pollution control expenditures.

Base Case Scenario

The base case scenario reflects the base assumptions regarding pollution control costs and coverages presented earlier, as well as assumptions concerning demand growth, etc., reflected in the baseline financial projection. The results of the base case analysis are summarized in Figure VI-8. Additional detail on pollution control costs is provided in Table VI-26. Among other things, these data indicate that pollution control expenditures under the base case scenario result in consumer charge increases of 5.01 mills per kWh by 1999. Cumulative plant additions during the 1980-1999 period are $87.28 billion, or 8 percent, over what would have been spent in the absence of pollution control regulations.

Table VI-26

FINANCIAL EFFECTS OF ALL POLLUTION CONTROL EXPENDITURES:[1]
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[2]				
Total for Year	2.76	3.39	3.98	7.36
Total since 1979	2.76	18.45	35.84	87.28
External Financing				
Total for Year	5.36	2.29	2.50	6.86
Total since 1979	5.36	16.86	28.43	68.18
Operating Revenues				
Total for Year	8.44	11.27	13.23	18.72
Total since 1979	8.44	58.30	120.41	263.26
Operation and Maintenance Expenses[3]				
Total for Year	7.39	8.61	9.42	12.02
Total since 1979	7.39	48.28	93.58	190.29
Consumer Charges (mills/kWh)				
Average for Year	3.97	4.56	4.62	5.01

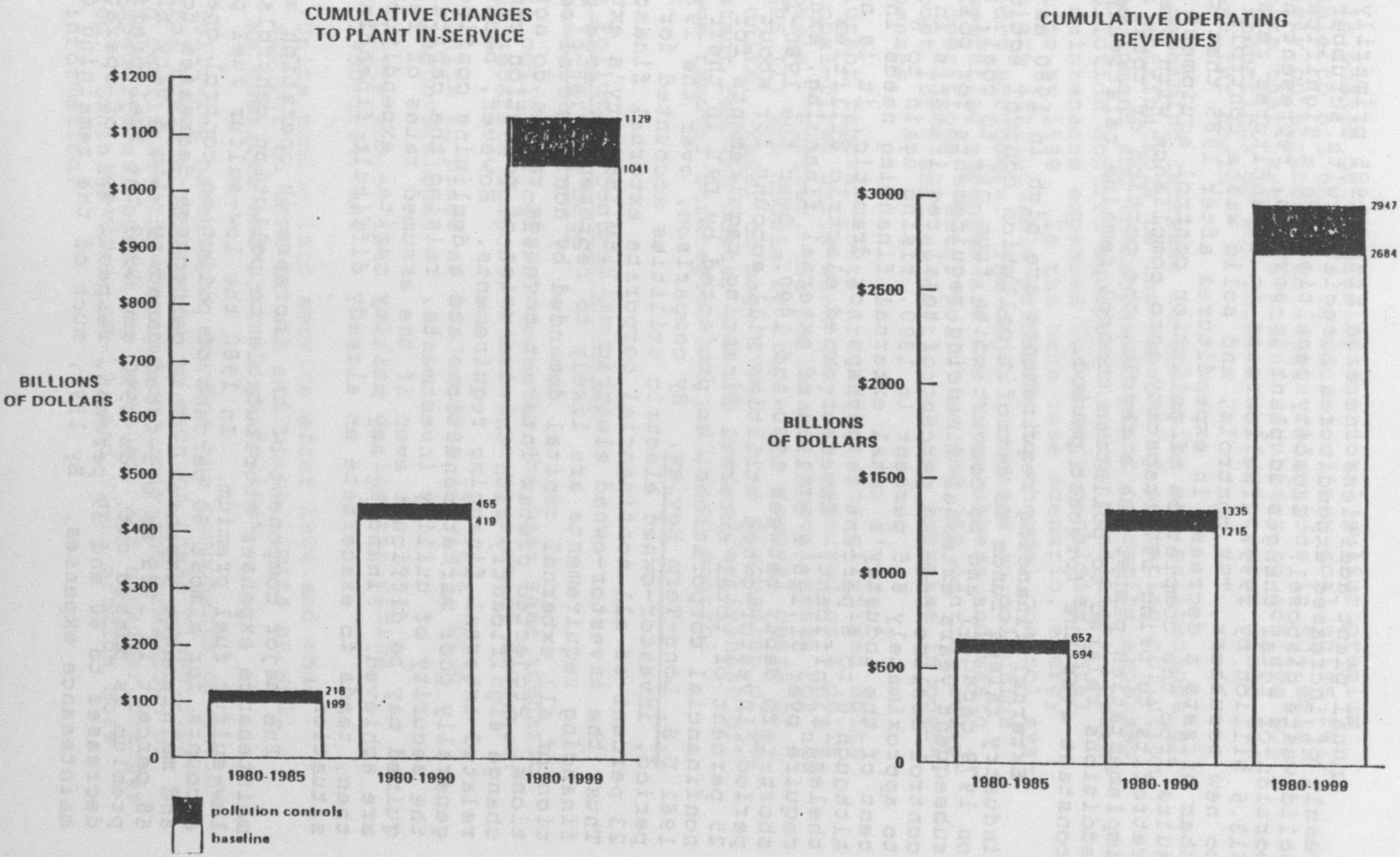
[1]As defined in this study.
[2]Excludes changes in construction work in progress.
[3]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Figure VI—8

CUMULATIVE CHANGES TO PLANT IN-SERVICE AND OPERATING REVENUES: BASE CASE SCENARIO

CONSTANT 1982 DOLLARS



Source: PTm(Electric Utilities).

Annual plant additions increase after 1985 primarily as a result of increased expenditures associated with scrubbers and solid waste disposal. Capacity penalties are a significant portion of total changes in plant in-service, representing $13.6 billion by 1999. The increase in expenditures related to new scrubbers, TSP controls, and solid waste controls more than offsets a decrease in expenditures after 1985 that results from the completion of pollution control equipment retrofits to bring 1979 capacity into compliance with state implementation plans. As a result, the portion of total plant additions related to pollution control remains relatively constant over the forecast period.

External financing requirements are high in 1980 as the industry raises funds to retrofit pollution control equipment on 1979 capacity and to convert units from oil to coal, but in subsequent years external financing requirements for pollution control decline from 50 percent of total requirements in 1980 to approximately 6.5 percent in 1990, rising again to 8 percent of the industry's total external financing needs in 1999. Although 6 to 8 percent is perhaps not dramatic, it is nonetheless significant. Investor-owned electric utilities will require over $1,128.8 billion of external financing, excluding short-term debt, between 1980 and 1999. Over the 1980-1999 period, investor-owned utilities will account for about 25 percent of total external financing requirements for all nonfinancial corporations, as projected by DRI in their Fall 1981 U.S. Long-Term Review. By comparison, over the 1970-1976 period, investor-owned electric utilities accounted for 23 percent of all nonfinancial corporate external financing. Thus, the investor-owned electric utility industry's external financing requirements are likely to represent a large proportion of all external capital demanded by nonfinancial corporations. Projected pretax interest coverage ratios do not change significantly with the inclusion of pollution control-related external financing requirements. However, because of generally poor market conditions and a declining confidence in the security of utility investments, raising the capital required may be difficult even if the assumed rates of return are achieved. Financing any utility capital expenditures, then, tends to exacerbate an already difficult financing situation.

The major component of the increase in operation and maintenance expenses attributable to pollution controls is the low-sulfur fuel premium. In 1980 the low-sulfur fuel premium accounts for almost 80 percent of pollution control operation and maintenance expenses. This percentage decreases to about 68 percent in 1985 as oil-fired capacity with a very high fuel premium is phased out. In 1990 and 1999 the fuel premium decreases to 60 and 39 percent, respectively, of operation and maintenance expenses. By 1999, much of the remaining oil capacity is phased out, reducing the total sulfur premium attributable to oil units. In addition, new coal units rely increasingly on scrubbers to attain reductions in SO_2 emissions; units that have high-sulfur scrubbers to achieve SO_2 emission reductions do not incur a sulfur premium since they use high-sulfur coals.

The remaining increase in operation and maintenance expenses is attributable to the expense of operating pollution control equipment and to increased plant operating expenses due to pollution control equipment energy penalties. Operation and maintenance expenses for energy penalties total $6.5 billion by 1999. In the base case scenario, energy penalties are attributable primarily to thermal control systems and dry scrubbers. The major increases in pollution control operating expenses are due to scrubbers and waste disposal operations. Water pollution and TSP control equipment account for a smaller portion of the increase in operating expenses.

Pollutant removal costs are higher for oil-fired units than for coal-fired units when they are measured on a dollar-per-ton basis. Further, the pollutant removal costs for new units (NSPS II) are double or triple the removal costs of existing units. Refer to page IV-10 for a discussion of per-ton pollutant removal costs, and the cost-effectiveness of alternative removal strategies and pollution control equipment.

Base Pollution Control Costs by Unit In-Service Date

Total pollution control costs in the base case scenario have three separate components based on regulatory coverage:

- Units in place as of December 31, 1979, plus reconversions,
- Units coming into service during the period 1980-1984, and
- Units coming into service after 1984 and thus subject to NSPS II air pollution limits as well as chemical and thermal guidelines.

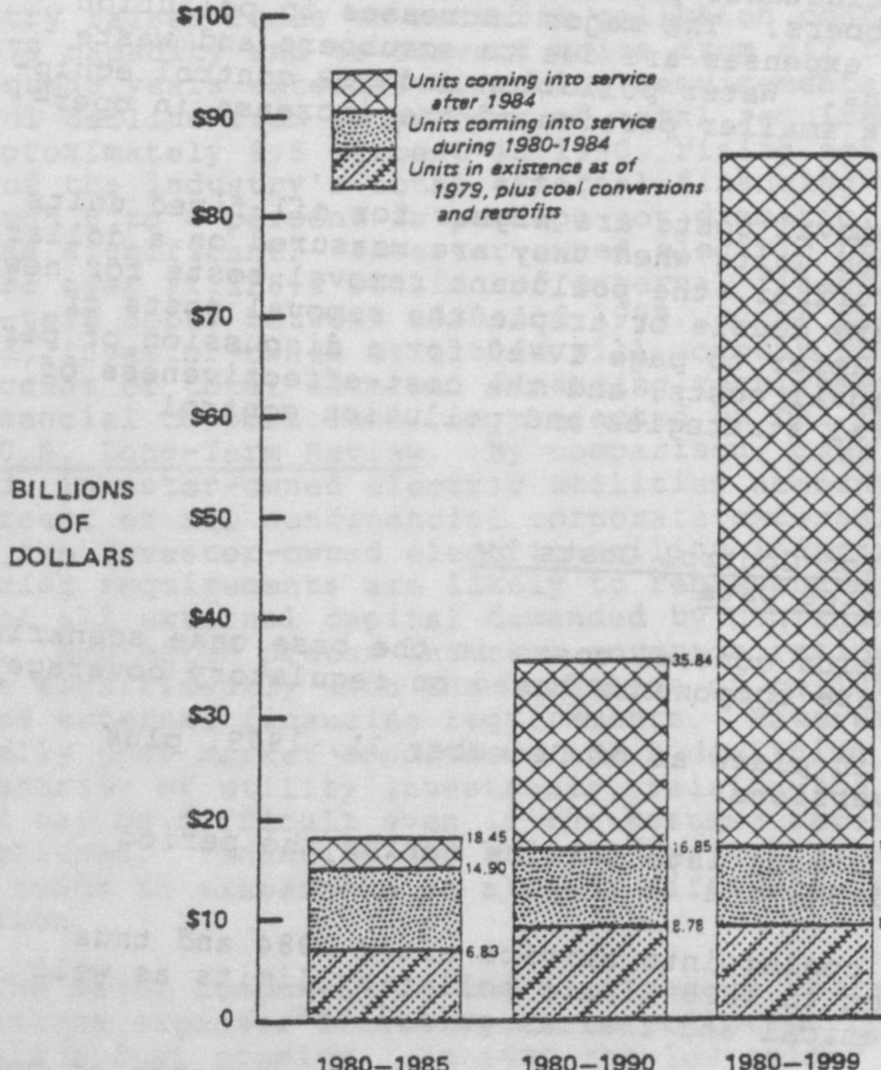
The following paragraphs examine the components of pollution control costs attributable to each of these classifications. To facilitate the discussion, only the breakdown of capital expenditures, operating revenues, and consumer charges is analyzed. Exhibits VI-9, VI-10, and VI-11 provide more detailed information.

Three types of changes in plant in-service--equipment retrofits on existing coal capacity, retrofits on reconverted coal units, and equipment installation on new units--contribute to high expenditures in 1980. As indicated by Figure VI-9, plant additions associated with retrofit pollution control equipment for units installed as of 1979 plus pollution

Figure VI–9

CUMULATIVE POLLUTION CONTROL ADDITIONS BY UNIT IN-SERVICE YEAR: BASE CASE SCENARIO

CONSTANT 1982 DOLLARS



Source: PTm(Electric Utilities).

controls for reconverted units are $6.8 billion in the 1980-1985 period, but total only $8.78 billion by 1999. By 1985, retrofits have been completed and the only remaining expenditures are those associated with reconversions. Units coming into service during 1980-1984 incur total pollution control plant additions of $8.07 billion over the forecast period. Units coming into service in 1985 and after incur the largest portion of pollution control additions to plant in-service, $70.43 billion. These expenditures, which represent 81 percent of total pollution control expenditures over the study period, are primarily related to compliance with NSPS II air regulations and solid waste disposal requirements that are increased due to the removal of air pollutants.

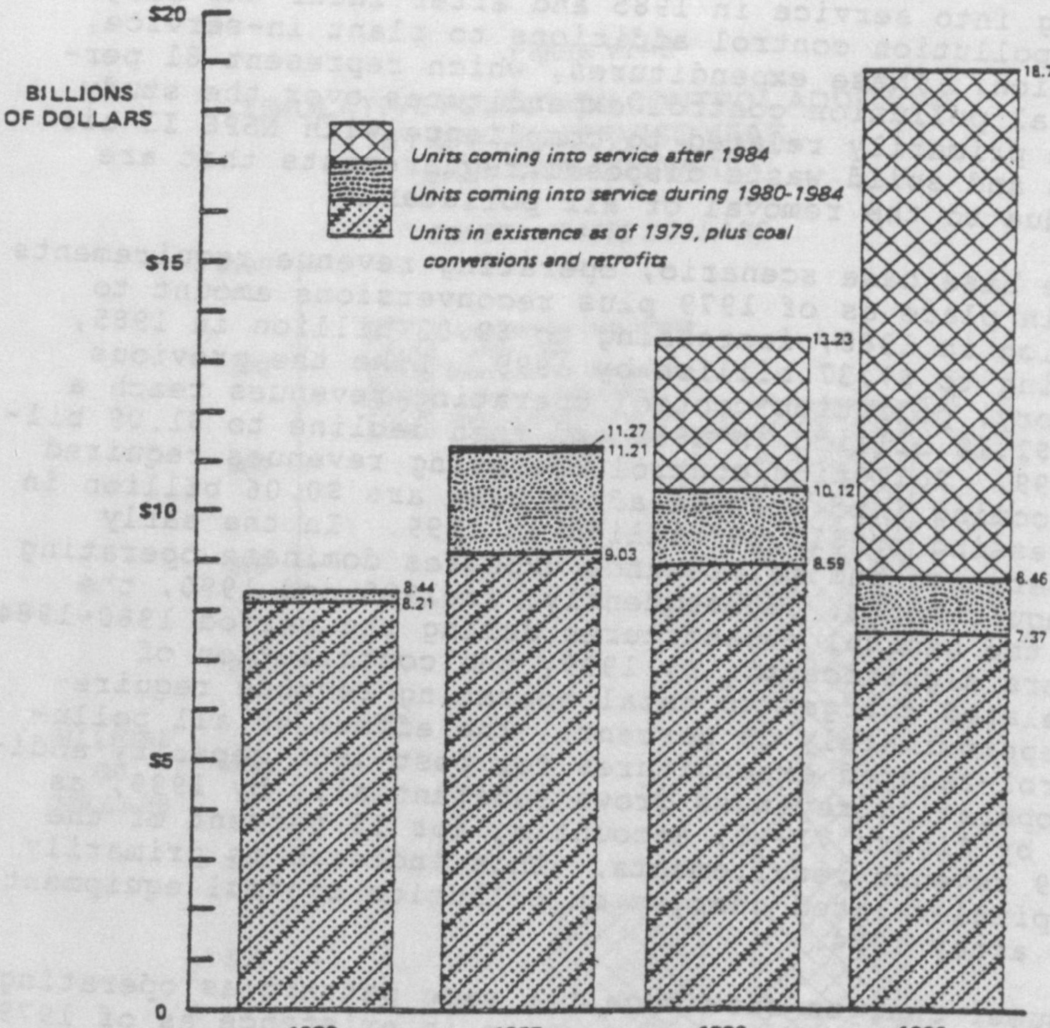
In the base case scenario, operating revenue requirements for units in place as of 1979 plus reconversions amount to $8.21 billion in 1980, increasing to $9.03 billion in 1985, and declining to $7.37 billion by 1999. Like the previous unit category, pollution control operating revenues reach a height of $2.18 billion in 1985 and then decline to $1.09 billion in 1999. Pollution control operating revenues required for units coming into service after 1984 are $0.06 billion in 1985, increasing to $10.26 billion in 1999. In the early period, operation and maintenance expenses dominate operating revenue requirements. Subsequently, in 1985 and 1990, the effect of the capital expenditures during the period 1980-1984 becomes more significant. By 1999, the contribution of capital-related charges to total operating revenue requirements is approximately 28 percent. The effect of all pollution control-related expenditures for post-1984 capacity additions on operating revenues grows substantially by 1999, as indicated by Figure VI-10, accounting for 55 percent of the total 1999 revenue requirements. This increase is primarily due to capital-related charges on pollution control equipment installed after 1984.

Consumer charges show much the same pattern as operating revenues. Consumer charges for units in existence as of 1979 (including reconversions) decrease over time as the sulfur premium is spread over more kilowatt-hours, as indicated by Figure VI-11. Pollution control costs for units coming into service between 1980 and 1984 rise initially as units come on line and then decline. The effects on consumer charges of pollution control expenditures for units coming into service after 1984 are barely perceptible in 1985, but account for more than 55 percent of the increase in consumer charges due to pollution control equipment by 1999. This increase in consumer charges results primarily from capital-related charges on pollution control equipment installed after 1985.

Figure VI—10

ANNUAL POLLUTION CONTROL OPERATING REVENUES BY IN-SERVICE YEAR: BASE CASE SCENARIO

CONSTANT 1982 DOLLARS



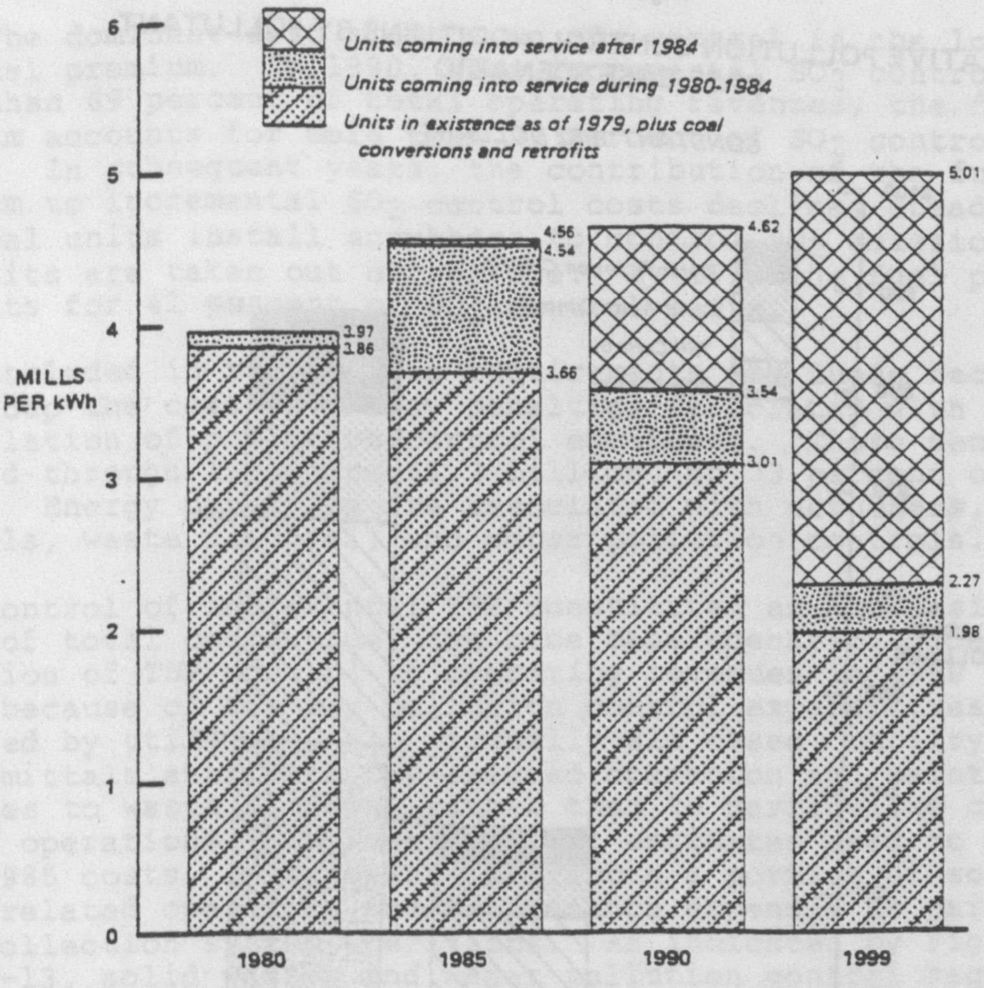
Source: PTm(Electric Utilities).

A decrease in the low-sulfur fuel premium compensates partially for the effect on consumer charges of increased capital expenditures for pollution control equipment. Fewer NSPS II units than pre-1985 units incur a low-sulfur fuel premium both because more capacity additions after 1985 are located in the West, and because most eastern units install scrubbers with 90 percent removal efficiencies and burn high-sulfur coal, and therefore do not incur fuel premiums.

Figure VI-11

ANNUAL POLLUTION CONTROL CONSUMER CHARGES BY UNIT IN-SERVICE YEAR: BASE CASE SCENARIO

CONSTANT 1982 DOLLARS



Source: PTm(Electric Utilities).

Pollution Control Expenditures by Pollutant

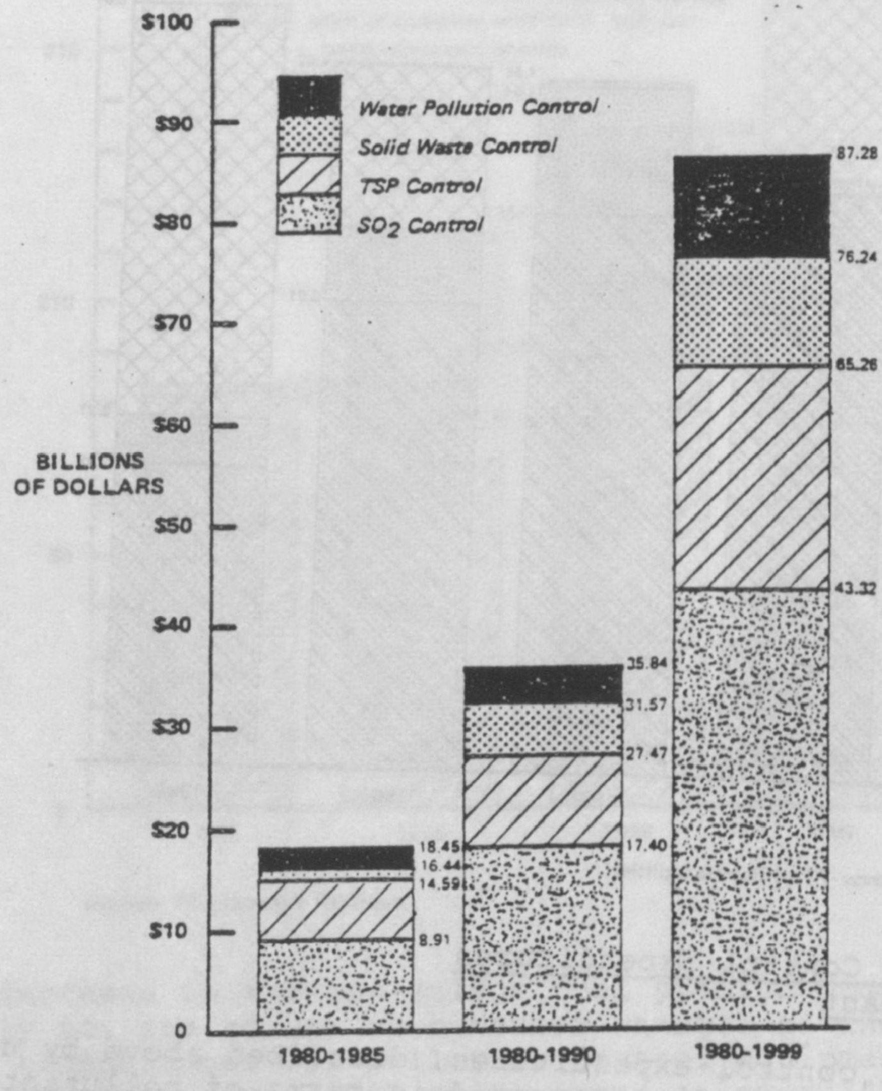
Pollution control expenditures, described above by unit in-service dates, are disaggregated in terms of pollutants controlled in the following discussion. The costs reviewed are the same as those above. Exhibits VI-12 through VI-18 provide more detailed information.

The largest component of total pollution control plant additions is SO_2 control, which represents 48 percent of total costs in 1980 and 50 percent in 1999. Based on Figure VI-12, TSP plant additions also increase over the period, representing 26 percent of total expenditures by 1999. Solid waste

Figure VI—12

CUMULATIVE POLLUTION CONTROL ADDITIONS BY POLLUTANT: BASE CASE SCENARIO

CONSTANT 1982 DOLLARS



Source: PTm(Electric Utilities).

disposal expenditures consist of the costs incurred in disposing of wastes generated by TSP and SO_2 removal systems.[4] These expenditures account for 13 percent of the total change in plant in-service; water pollution controls are also 13 percent of the total pollution control plant additions. Total capacity penalties associated with SO_2, TSP, and water pollution controls amount to $13.6 billion by 1999.

The dominant cost element in SO_2 control is the low-sulfur fuel premium. In 1980, when incremental SO_2 control is more than 69 percent of total operating revenues, the fuel premium accounts for more than 97 percent of SO_2 control costs. In subsequent years, the contribution of the fuel premium to incremental SO_2 control costs declines steadily as new coal units install scrubbers to control SO_2 emissions and oil units are taken out of service. By 1999 the fuel premium accounts for 41 percent of SO_2 control costs.

Included in the revenue requirements are funds necessary to recoup the cost of energy penalties associated with the installation of pollution control equipment. Those penalties, totaled through 1999, are $6.2 billion, or 33 percent of the total. Energy penalties are associated with scrubbers, TSP controls, waste disposal, and water pollution controls.

Control of incremental TSP constitutes an increasing share of total costs under the base case scenario. The contribution of TSP control to operating revenues in 1980 is small because of the way pollution control expenditures are reported by utilities. In virtually all cases, utility Form 67 submittals attribute TSP-related operation and maintenance expenses to waste disposal rather than to particulate control system operations. Engineering cost estimates used to develop post-1985 costs, in contrast, attribute a portion of solid waste-related operation and maintenance expenses to particulate collection system operations. As indicated by Figure VI-13, solid wastes and water pollution control requirements constitute a much smaller share of total operating revenues associated with pollution control equipment.

The discussion related to consumer charges follows much the same pattern as that for operating revenues. Figure VI-14 details the cost components of consumer charges by pollutant. As is the case for operating revenues, incremental SO_2 and TSP

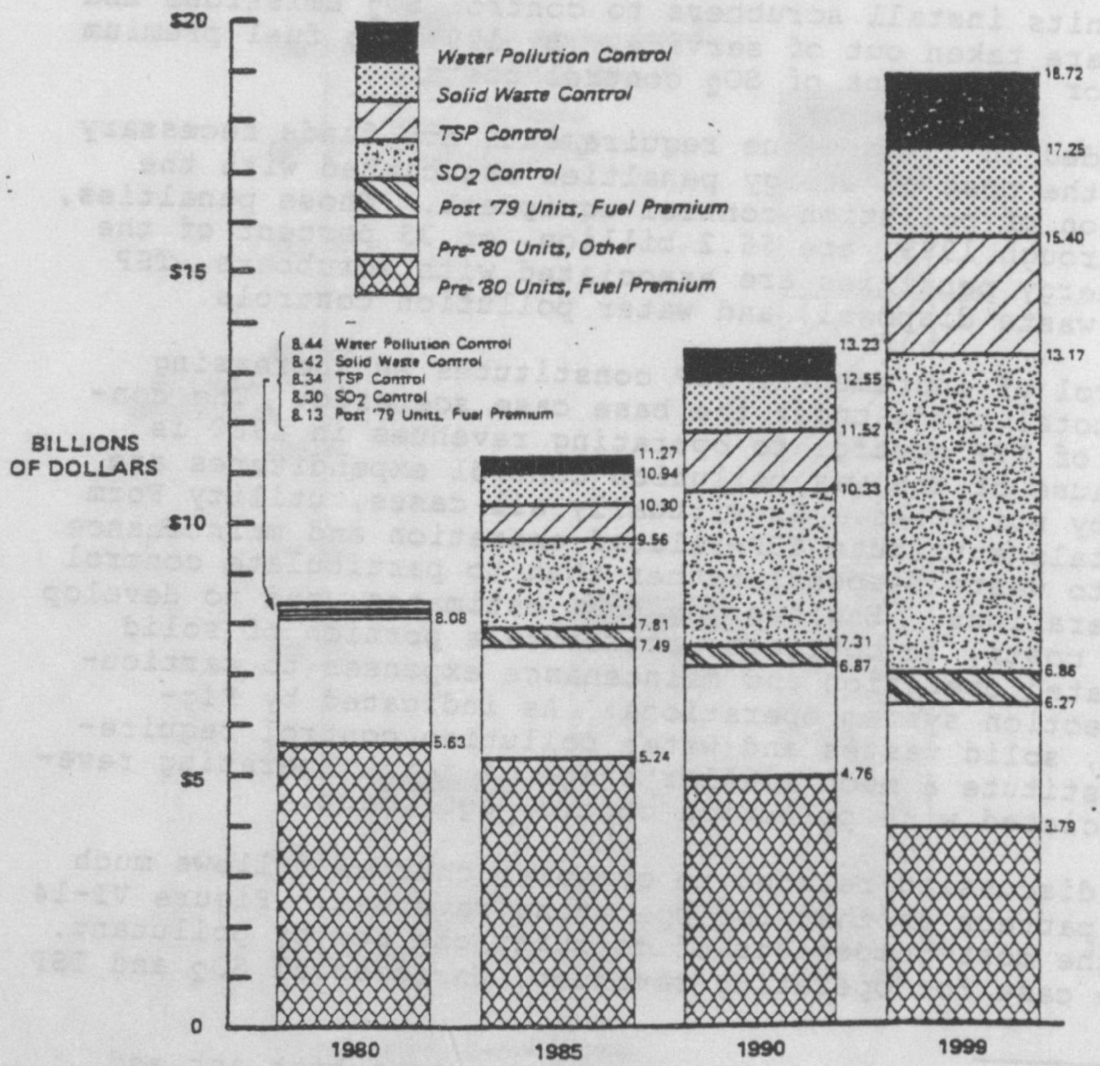
[4] Since solid waste disposal facilities accept both ash and scrubber residues, the contribution of SO_2 and TSP controls to solid waste costs cannot be readily disentangled.

controls are the primary source of consumer charges associated with pollution controls. Together they account for 69 percent of the pollution control-related consumer charge increase in 1999. However, the contribution of incremental solid waste and water pollution controls grows over time from 1 percent in 1980 to 18 percent in 1999.

Figure VI—13

ANNUAL POLLUTION CONTROL REVENUES BY POLLUTANT: BASE CASE SCENARIO

CONSTANT 1982 DOLLARS

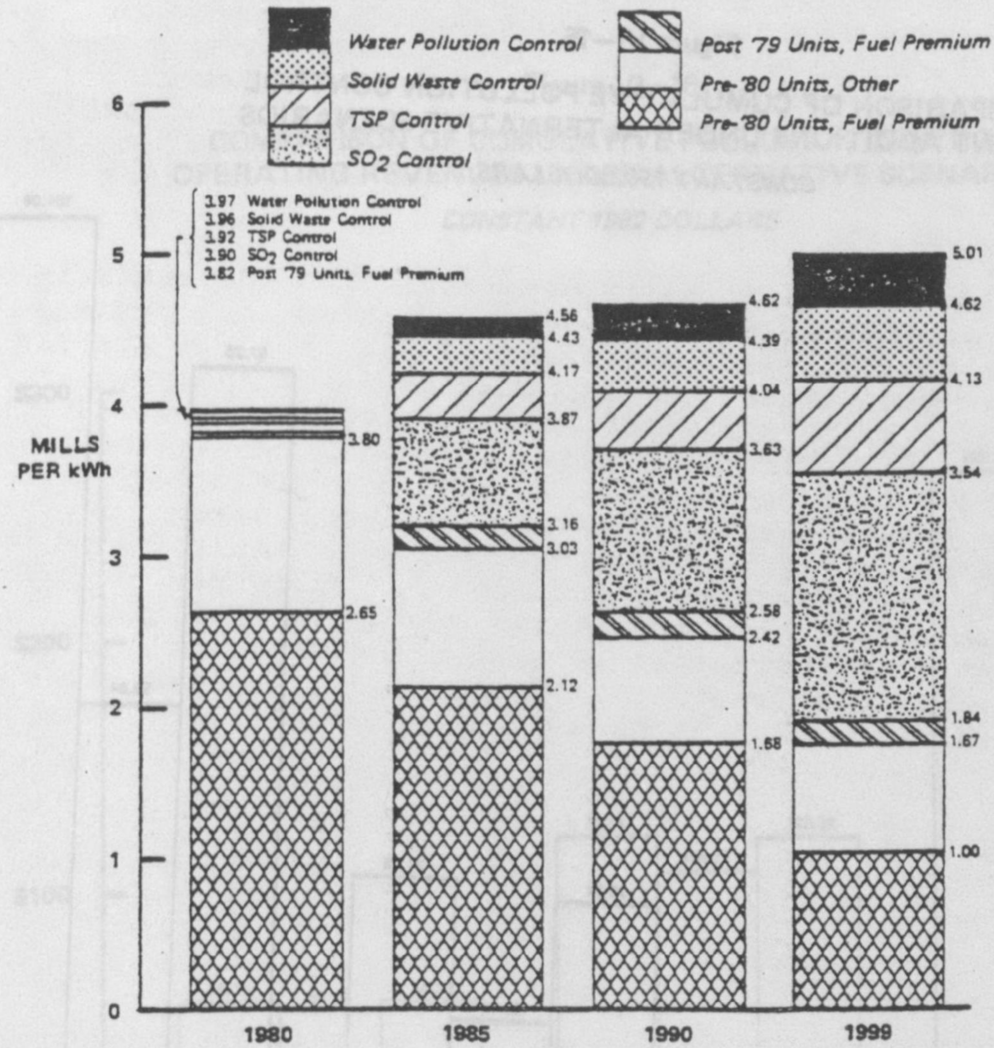


Source: PTm(Electric Utilities).

Figure VI—14

AVERAGE POLLUTION CONTROL CONSUMER CHARGES BY POLLUTANT: BASE CASE SCENARIO

CONSTANT 1982 DOLLARS



Source: PTm(Electric Utilities).

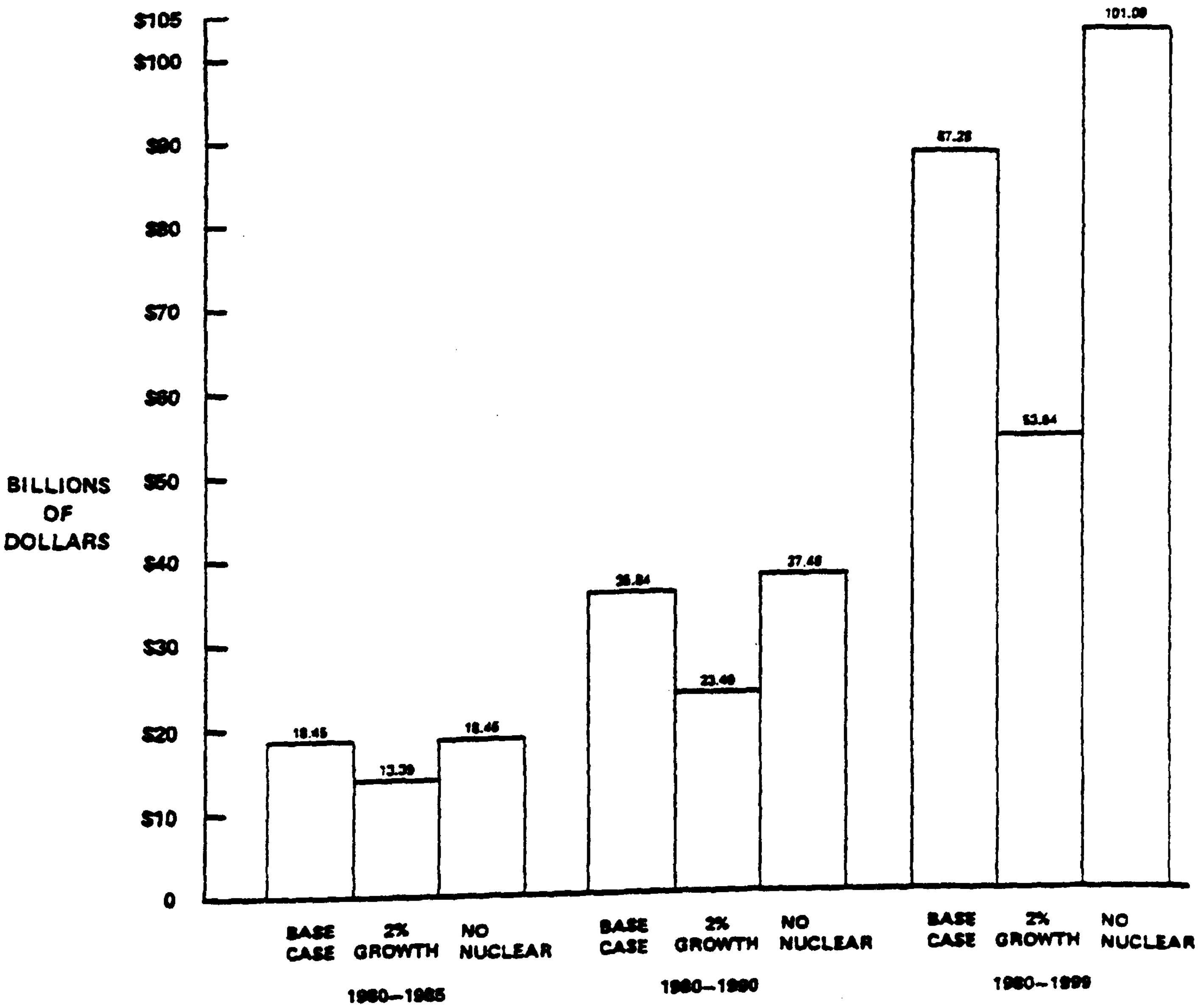
Alternative Scenarios

TBS tested two key assumptions in the base case scenario by developing alternative hypotheses and identifying the effects of these hypotheses on the results of the analysis. The two key assumptions tested were lower industry growth and termination of nuclear capacity additions after 1989. The effects of the alternative scenarios on pollution control plant additions and operating revenues are shown in Figures VI-15 and VI-16. These effects are shown in further detail in Exhibits VI-19 and VI-20. All pollution control effects are measured against a corresponding base financial projection. (The base financial projections for these two scenarios were

Figure VI-15

COMPARISON OF CUMULATIVE POLLUTION CONTROL PLANT ADDITIONS UNDER ALTERNATIVE SCENARIOS

CONSTANT 1982 DOLLARS



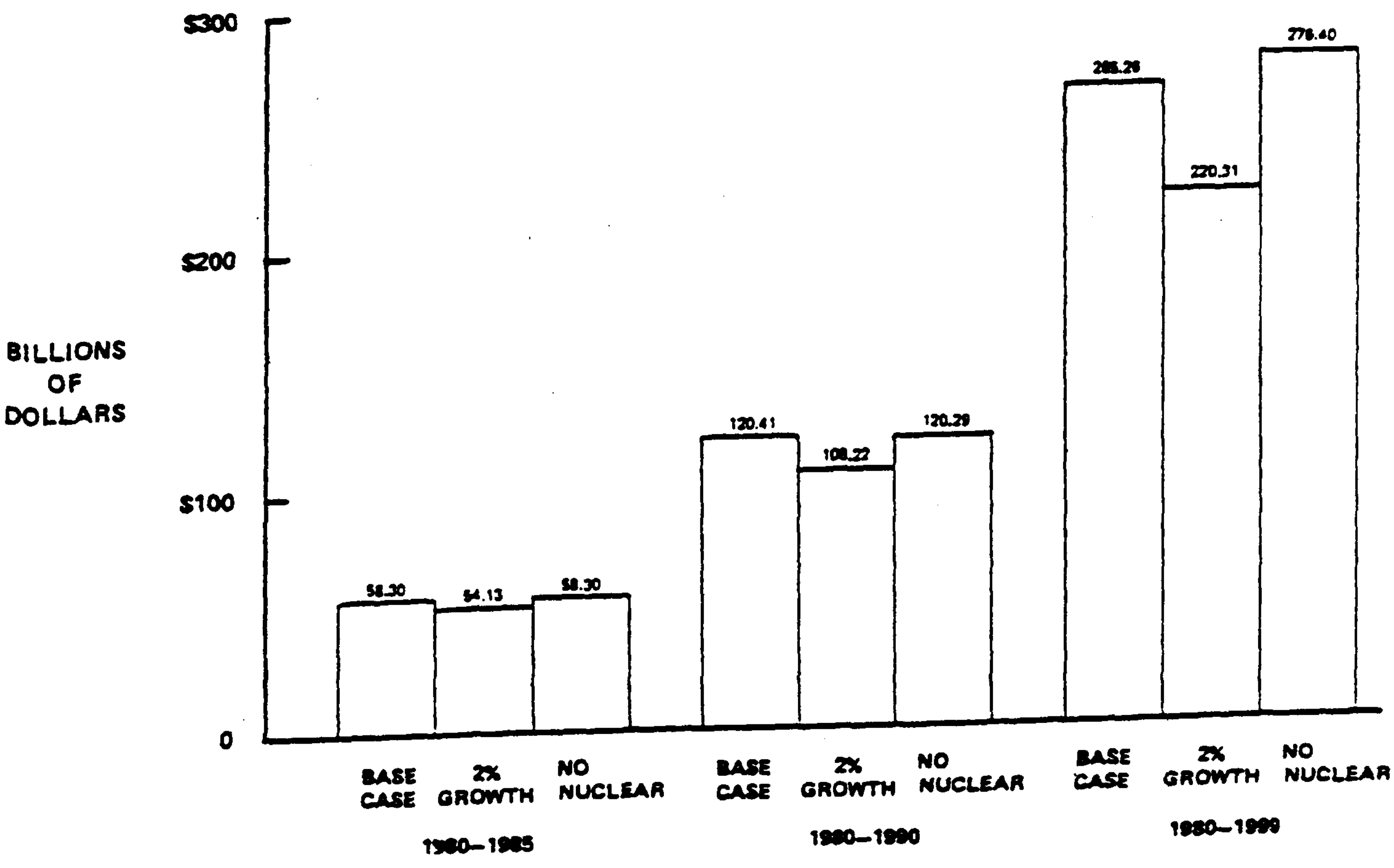
Source: PTm(Electric Utilities).

presented earlier in Tables VI-21 and VI-22.) The comparisons provide an indication of the change in pollution control-related costs, recognizing that the underlying costs and financial profiles also vary between scenarios.

Figure VI-16

COMPARISON OF CUMULATIVE POLLUTION CONTROL OPERATING REVENUES UNDER ALTERNATIVE SCENARIOS

CONSTANT 1982 DOLLARS



Source: FTm(Electric Utilities).

A decrease in the industry's near-term annual growth rate, from the 3.0 percent assumed in the base case to 2 percent, decreases the industry's total costs, both with and without pollution controls. Total pollution control plant additions through 1999 are $33.64 billion lower as a consequence of a slower annual growth rate. Similarly, total pollution control operating revenues through 1999 decrease by $44.95 billion from the base case. As operating revenue requirements decrease, however, so do total kWh of generation. Consequently, consumer charges do not decline as significantly. The largest decrease in pollution control consumer charges takes place in 1999, but even then it decreases by less than 0.4 mills per kWh (7 percent).

Termination of nuclear additions results in increases in all pollution control-related expenditure categories. Cumulative pollution control plant additions of $101 billion are $14 billion greater than under the base case scenario. Annual pollution control plant additions are $8.7 billion by 1999. Cumulative revenue requirements associated with pollution controls are $276 billion by 1999, $11 billion greater than under the base case scenario. Average consumer charges increase by 0.64 mills per kWh over the case of continued nuclear additions, representing a total of 5.7 mills per kWh by 1999 for all pollution control-related expenses. This increase amounts to approximately 10 percent of the baseline cost of generating electricity, assuming no nuclear additions after 1989. This corresponds to 9 percent for the base case scenario.

PIm(ELECTRIC UTILITIES) MODEL
BALANCE SHEET FOR INVESTOR-OWNED ELECTRIC UTILITIES

(billions of current dollars)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ASSETS											
CURRENT ASSETS	23.7	26.7	29.8	33.6	37.8	43.7	50.3	57.1	64.5	72.7	81.9
LONG TERM ASSET ACCOUNTS											
GROSS PLANT IN SERVICE	202.1	223.2	247.3	274.9	306.5	348.0	394.2	444.5	499.6	561.4	640.6
-ACCUM. DEPRECIATION	51.4	55.7	60.6	66.2	72.6	79.6	87.7	97.2	108.0	120.4	135.9
NET PLANT IN SERVICE	150.8	167.5	186.8	208.7	233.9	268.4	306.4	347.4	391.7	441.0	504.7
+NUC. FUEL (NET)	3.4	3.6	4.5	6.2	7.4	9.4	12.0	15.1	18.0	21.3	24.9
+CWIP	46.7	54.6	63.9	75.0	89.6	100.7	112.3	127.1	147.7	173.9	193.8
NET ELECTRIC PLANT	200.9	225.8	255.2	289.9	330.8	378.4	430.7	489.5	557.3	636.2	723.4
TOTAL ASSETS	224.6	252.5	285.0	323.4	368.6	422.1	481.1	546.7	621.8	708.9	805.3
LIABILITIES											
CURRENT LIABILITIES											
SHORT TERM DEBT	6.7	7.5	8.4	9.5	10.8	12.3	14.0	15.8	18.0	20.5	23.2
OTHER CURRENT LIABILITIES	3.7	5.9	8.1	10.7	13.6	18.1	23.0	28.0	33.2	38.9	45.3
LONG TERM LIABILITIES											
ACCUM. DEFERRALS	15.0	16.9	18.9	21.1	23.6	26.4	29.6	33.3	37.4	42.0	47.3
ACCUM. DEFERRED ITC	7.1	8.0	8.9	9.9	11.0	12.6	14.3	16.1	18.2	20.4	23.3
LONG TERM DEBT											
POST 1979	7.8	20.7	36.2	53.7	74.5	97.6	122.8	150.8	182.9	219.8	260.5
TOTAL	96.3	107.4	120.4	136.1	154.8	176.4	200.1	226.7	257.6	293.6	333.1
PREFERRED STOCK											
POST 1979	.8	2.6	4.9	7.4	9.9	13.0	17.7	23.1	29.2	36.4	44.3
TOTAL	23.1	24.9	27.2	29.7	32.2	35.3	40.0	45.3	51.5	58.7	66.6
OWNERS EQUITY											
POST 1979 CASH ISSUES	3.2	10.2	18.4	28.1	39.8	52.6	65.0	79.4	96.3	116.0	137.5
POST 1979 RETAINED EARN.	1.9	4.1	7.0	10.5	15.0	20.8	27.3	34.3	42.0	51.1	61.2
TOTAL	72.8	82.1	93.2	106.4	122.6	141.1	160.1	181.4	206.1	234.9	266.4
TOTAL CAPITALIZATION	192.1	214.3	240.7	272.1	309.5	352.8	400.2	453.5	515.1	587.2	666.1
TOTAL LONG TERM LIABILITIES	214.2	239.1	268.5	303.2	344.2	391.7	444.0	502.9	570.7	649.5	736.7
TOTAL LIABILITIES	224.6	252.5	285.0	323.4	368.6	422.1	481.1	546.7	621.8	708.9	805.3

Exhibit VI-2

PIm(ELECTRIC UTILITIES) MODEL
INCOME STATEMENT FOR INVESTOR-OWNED ELECTRIC UTILITIES

(billions of current dollars)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
OPERATING REVENUE	74.0	83.1	92.9	104.5	117.7	136.3	156.9	178.0	201.0	226.5	255.2
-OPER. & MAINT. EXP.	47.3	52.4	57.8	64.0	71.3	79.7	90.2	101.6	113.7	126.8	142.0
-O/M EXP. - THERMAL	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
-O/M EXP. - CHEMICAL	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
-USAGE TAX	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
-TAXES (OTHER)	5.6	6.3	7.1	7.9	8.9	10.4	11.9	13.5	15.3	17.2	19.4
-DEPRECIATION - PLANT	4.9	5.5	6.1	6.8	7.6	8.6	9.7	11.0	12.4	14.0	15.9
-DEPRECIATION - NUC FUEL	1.6	1.8	2.1	2.9	3.3	4.3	5.6	6.8	8.5	10.3	12.1
+OPT. & CREDIT	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
+AFDC	6.7	7.5	9.2	11.3	14.1	17.1	18.6	19.8	22.3	26.6	30.0
EBIT	21.1	24.7	28.9	34.2	40.7	50.4	58.0	64.9	73.4	84.9	95.8
-INTEREST ON LONG TERM DEBT	6.5	7.6	9.0	10.0	13.3	16.1	19.1	22.2	25.7	29.9	34.4
-INTEREST ON SHORT TERM DEBT	1.0	1.0	1.1	1.2	1.3	1.5	1.6	1.8	2.0	2.3	2.5
EBT	13.7	16.1	18.9	22.2	26.1	32.8	37.3	41.0	45.7	52.8	58.9
-TAXES (INCOME)	.0	.5	.8	1.0	1.1	2.0	2.7	3.2	3.5	3.9	3.4
-DEFERRED TAXES	1.8	1.9	2.0	2.2	2.4	2.8	3.2	3.6	4.1	4.6	5.4
-DEFERRED ITCS	.8	.9	.9	1.0	1.1	1.5	1.7	1.9	2.0	2.2	2.9
NET INCOME	11.1	12.8	15.1	17.9	21.4	26.5	29.6	32.3	36.1	42.1	47.2
-DIVIDENDS (PREF)	1.8	1.9	2.2	2.5	2.8	3.2	3.8	4.4	5.1	5.9	6.8
-DIVIDENDS (COMM)	7.5	8.6	10.1	11.9	14.1	17.4	19.4	20.9	23.3	27.1	30.3
RETAINED EARNINGS	1.9	2.3	2.8	3.6	4.5	5.8	6.5	7.0	7.8	9.0	10.1
COVERAGE RATIOS											
EBIT/INTEREST	3.3	3.3	3.2	3.2	3.1	3.1	3.0	2.9	2.9	2.8	2.8
EBIT/INT + PFD DIV	2.6	2.6	2.6	2.6	2.5	2.6	2.5	2.4	2.4	2.4	2.3

Exhibit VI-3

PTm(ELECTRIC UTILITIES) MODEL
APPLICATIONS AND SOURCES OF FUNDS
FOR INVESTOR-OWNED ELECTRIC UTILITIES

(billions of current dollars)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
APPLICATIONS OF FUNDS											
CAPTIAL EXPENDITURES											
CAP. EXPEND. FOR PLANT	12.7	22.6	25.4	28.5	33.3	37.0	40.8	46.9	55.0	62.8	69.4
INIT. LOADING NUC. FUEL	.2	.3	.4	.4	.5	1.1	1.3	1.4	1.6	1.8	1.7
NET REPLACEMENT	-.5	.0	.5	1.2	.7	.9	1.4	1.6	1.3	1.5	1.9
AFDC	6.7	7.5	9.2	11.3	14.1	17.1	18.6	19.8	22.3	26.6	30.0
+REFUNDINGS	2.0	1.8	2.5	1.8	2.1	1.5	1.4	1.4	1.3	.9	1.2
TOTAL APPLICATIONS	21.1	32.2	38.0	43.3	50.7	57.6	63.5	71.2	81.5	93.7	104.3
SOURCES OF FUNDS											
INTERNAL GENERATION											
RETAINED EARNINGS	1.9	2.3	2.8	3.6	4.5	5.8	6.5	7.0	7.8	9.0	10.1
+DEPRECIATION-PLANT	4.9	5.5	6.1	6.8	7.6	8.6	9.7	11.0	12.4	14.0	15.9
+DEFERRALS	2.6	2.8	3.0	3.2	3.6	4.3	4.9	5.5	6.1	6.8	8.3
TOTAL	9.4	10.5	11.9	13.6	15.6	18.7	21.1	23.5	26.3	29.8	34.2
EXTERNAL FINANCING											
LONG-TERM DEBT	7.8	12.9	15.5	17.5	20.8	23.1	25.1	28.0	32.1	36.9	40.7
+STOCK (PREF)	.8	1.8	2.3	2.5	2.5	3.1	4.7	5.3	6.2	7.2	7.9
+STOCK (COMM)	3.2	7.0	8.2	9.7	11.7	12.7	12.5	14.3	16.9	19.8	21.5
TOTAL	11.8	21.7	26.1	29.7	35.1	38.9	42.4	47.7	55.2	63.8	70.1
TOTAL SOURCES	21.1	32.2	38.0	43.3	50.7	57.6	63.5	71.2	81.5	93.7	104.3
CUM. EXTERNAL FINANCING	11.8	33.4	59.5	89.2	124.3	163.2	205.5	253.3	308.4	372.3	442.4

Exhibit VI-4

PTm(ELECTRIC UTILITIES) MODEL
FUELS CONSUMED FOR GENERATION OF ELECTRICITY

CONVENTIONAL STEAM AND PEAKING UNITS

	TOTAL GENERATION	COAL (MM TONS)	OIL (MM BBLS)	GAS (BCF)
1980	2343.3	533.7	651.7	2583.6
1981	2413.6	563.4	639.2	2497.2
1982	2486.0	594.7	624.2	2412.0
1983	2560.6	626.3	611.7	2330.9
1984	2637.4	659.3	596.7	2248.9
1985	2716.5	693.8	572.1	2156.1
1986	2798.0	727.2	554.4	2149.6
1987	2881.9	762.5	535.6	2139.1
1988	2968.4	798.0	519.6	2137.9
1989	3057.4	835.7	502.4	2133.5
1990	3149.2	872.8	499.1	2121.1
1991	3243.6	907.5	488.8	2078.2
1992	3340.9	943.6	478.9	2038.6
1993	3441.2	980.0	469.9	2001.2
1994	3544.4	1018.0	460.7	1963.1
1995	3650.7	1068.5	441.6	1890.4
1996	3760.3	1125.7	411.3	1767.9
1997	3873.1	1183.8	382.9	1652.3
1998	3989.3	1241.5	357.2	1548.0
1999	4108.9	1301.3	332.8	1450.1

Exhibit VI-5

PTm(ELECTRIC UTILITIES) MODEL
TOTAL GENERATION BY DRIVER

(billion kWh)

	TOTAL GENER.	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED	PEAKER
1980	2343.3	1134.1	377.2	228.6	258.3	253.7	63.4	28.0
1981	2413.6	1190.5	368.4	219.7	283.7	257.4	64.4	29.5
1982	2486.0	1249.5	358.5	211.2	310.2	260.9	65.2	30.5
1983	2560.6	1308.3	349.7	202.8	337.9	263.8	65.9	32.0
1984	2637.4	1369.3	339.8	194.6	367.1	266.9	66.7	33.0
1985	2716.5	1432.7	324.5	185.7	409.5	264.6	66.1	33.3
1986	2798.0	1489.3	312.4	184.3	443.6	266.8	66.7	34.8
1987	2881.9	1548.3	300.1	182.8	478.7	268.9	67.2	35.8
1988	2968.4	1606.5	288.9	181.8	513.8	271.9	68.0	37.5
1989	3057.4	1667.9	277.0	180.5	550.0	274.3	68.6	39.2
1990	3149.2	1727.0	274.2	178.8	577.9	280.8	70.2	40.2
1991	3243.6	1792.9	267.8	174.7	607.3	288.5	72.1	40.3
1992	3340.9	1860.8	261.6	170.9	637.5	295.8	73.9	40.4
1993	3441.2	1929.2	255.5	167.0	668.7	303.8	75.9	41.1
1994	3544.4	2000.5	249.7	163.3	700.2	311.6	77.9	41.3
1995	3650.7	2097.1	237.8	156.3	723.7	315.4	78.8	41.6
1996	3760.3	2203.1	221.4	146.2	751.7	319.1	79.8	38.9
1997	3873.1	2310.0	206.2	136.8	780.2	322.9	80.7	36.1
1998	3989.3	2415.4	192.3	128.2	810.7	327.1	81.8	33.8
1999	4108.9	2524.1	179.2	120.2	840.1	331.1	82.8	31.5

Exhibit VI-6

PIm(ELECTRIC UTILITIES) MODEL
GROSS ADDITIONS TO GENERATING PLANT
INCLUDING CONVERSIONS TO COAL FROM OIL

(million kilowatts)

	TOTAL CAPACITY	TOTAL ADDTNS.	FOSSIL SUBTOTAL	COAL	OIL	GAS	NUCLEAR	HYDRO	PUMPED	PEAKER
1980	569.6	15.9	8.8	8.8	.0	.0	3.1	1.3	.3	2.4
1981	582.6	15.9	8.8	8.8	.0	.0	3.1	1.3	.3	2.4
1982	595.6	15.9	8.8	8.8	.0	.0	3.1	1.3	.3	2.4
1983	608.7	15.9	8.8	8.8	.0	.0	3.1	1.3	.3	2.4
1984	621.7	15.9	8.8	8.8	.0	.0	3.1	1.3	.3	2.4
1985	636.2	17.8	10.8	10.8	.0	.0	5.6	.5	.1	.8
1986	650.7	17.8	10.8	10.8	.0	.0	5.6	.5	.1	.8
1987	665.2	17.8	10.8	10.8	.0	.0	5.6	.5	.1	.8
1988	679.7	17.8	10.8	10.8	.0	.0	5.6	.5	.1	.8
1989	694.2	17.8	10.8	10.8	.0	.0	5.6	.5	.1	.8
1990	713.0	19.0	12.2	12.2	.0	.0	4.7	1.7	.4	.0
1991	731.7	19.0	12.2	12.2	.0	.0	4.7	1.7	.4	.0
1992	750.5	19.0	12.2	12.2	.0	.0	4.7	1.7	.4	.0
1993	769.2	19.0	12.2	12.2	.0	.0	4.7	1.7	.4	.0
1994	788.0	19.0	12.2	12.2	.0	.0	4.7	1.7	.4	.0
1995	814.1	30.0	22.9	22.9	.0	.0	4.5	1.4	.3	.9
1996	840.1	30.0	22.9	22.9	.0	.0	4.5	1.4	.3	.9
1997	866.2	30.0	22.9	22.9	.0	.0	4.5	1.4	.3	.9
1998	892.3	30.0	22.9	22.9	.0	.0	4.5	1.4	.3	.9
1999	918.3	30.0	22.9	22.9	.0	.0	4.5	1.4	.3	.9

Exhibit VI-7

PTm(ELECTRIC UTILITIES) MODEL
SALES AND CAPACITY ASSUMPTIONS
U.S. ELECTRIC UTILITY INDUSTRY

	PEAK DEMAND (MW)	PEAK GROWTH (%)	RESERVE MARGIN (%)	CAPAB AT PEAK (MW)	YR END CAP (MW)	CAPACITY FACTOR (%)	TOTAL GENER (BIL)	GENER NOT SOLD (%)	SALES (BIL)	SALES GROWTH (%)	LOAD FACTOR (%)
1980	421.3	3.0	28.5	541.2	569.6	49.4	2343.3	9.0	2132.4	3.0	63.5
1981	433.9	3.0	27.6	553.7	582.6	49.8	2413.6	9.0	2196.3	3.0	63.5
1982	446.9	3.0	26.7	566.2	595.6	50.1	2486.0	9.0	2262.2	3.0	63.5
1983	460.3	3.0	25.7	578.7	608.7	50.5	2560.6	9.0	2330.1	3.0	63.5
1984	474.1	3.0	24.7	591.2	621.7	50.9	2637.4	9.0	2400.0	3.0	63.5
1985	488.4	3.0	23.8	604.6	636.2	51.3	2716.5	9.0	2472.0	3.0	63.5
1986	503.0	3.0	22.8	617.9	650.7	51.7	2798.0	9.0	2546.2	3.0	63.5
1987	518.1	3.0	21.8	631.3	665.2	52.1	2881.9	9.0	2622.6	3.0	63.5
1988	533.7	3.0	20.8	644.6	679.7	52.6	2968.4	9.0	2701.2	3.0	63.5
1989	549.7	3.0	19.7	658.0	694.2	53.0	3057.4	9.0	2782.3	3.0	63.5
1990	566.2	3.0	19.3	675.4	713.0	53.2	3149.2	9.0	2865.7	3.0	63.5
1991	583.1	3.0	18.8	692.8	731.7	53.4	3243.6	9.0	2951.7	3.0	63.5
1992	600.6	3.0	18.2	710.2	750.5	53.7	3340.9	9.0	3040.3	3.0	63.5
1993	618.6	3.0	17.6	727.6	769.2	54.0	3441.2	9.0	3131.5	3.0	63.5
1994	637.2	3.0	16.9	745.0	788.0	54.3	3544.4	9.0	3225.4	3.0	63.5
1995	656.3	3.0	17.2	769.1	814.1	54.2	3650.7	9.0	3322.2	3.0	63.5
1996	676.0	3.0	17.3	793.1	840.1	54.1	3760.3	9.0	3421.8	3.0	63.5
1997	696.3	3.0	17.4	817.2	866.2	54.1	3873.1	9.0	3524.5	3.0	63.5
1998	717.2	3.0	17.3	841.2	892.3	54.1	3989.3	9.0	3630.2	3.0	63.5
1999	738.7	3.0	17.1	865.3	918.3	54.2	4108.9	9.0	3739.1	3.0	63.5

Exhibit VI-8

UNIT POLLUTION CONTROL COSTS USED TO
DEVELOP POST-1984 COST ASSUMPTIONS

(1982 dollars)

	Capital $/kW	O&M (mills/kWh)	Capacity Penalty (% capacity)	Energy Penalty (% generation)
Eastern 90% Wet Scrubbing: <u>High-Sulfur Coal</u>				
Scrubber	127.42	1.83	2.18	3.54
Waste Disposal	53.98	0.37	0.03	0.03
TSP Control	43.03	0.21	0.21	0.21
Western 70% Dry Scrubbing: <u>Low-Sulfur Coal</u>				
Scrubber	83.99	1.08	0.59	1.43
Waste Disposal	4.47	0.51	0.00	0.00
TSP Control	68.51	0.72	0.95	0.95
Western 90% Wet Scrubbing: <u>Low-Sulfur Coal</u>				
Scrubber	116.35	1.67	1.53	3.43
Waste Disposal	24.34	0.22	0.00	0.00
TSP Control	74.27	0.36	0.21	0.21

Source: EPA.

Exhibit VI-9

FINANCIAL EFFECTS OF POLLUTION CONTROL EXPENDITURES
BY UNITS IN EXISTENCE AS OF 1979, PLUS COAL
CONVERSIONS AND RETROFITS:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	1.20	0.54	0.00	0.00
Total since 1979	1.20	6.83	8.78	8.78
External Financing				
Total for Year	2.17	0.07	(0.30)	(0.11)
Total since 1979	2.17	4.53	4.04	2.45
Operating Revenues				
Total for Year	8.21	9.03	8.59	7.37
Total since 1979	8.21	51.52	95.13	166.31
Operations and Maintenance Expenses[2]				
Total for Year	7.23	7.56	7.54	7.20
Total since 1979	7.23	44.62	82.37	149.37
Consumer Charges (mills/kWh)				
Average for Year	3.86	3.66	3.01	1.98

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-10

FINANCIAL EFFECTS OF POLLUTION CONTROL EXPENDITURES
BY UNITS COMING INTO SERVICE DURING 1980-1984:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	1.56	0.00	0.00	0.00
Total since 1979	1.56	8.07	8.07	8.07
External Financing				
Total for Year	3.19	(0.33)	(0.17)	(0.06)
Total since 1979	3.19	6.17	5.07	4.20
Operating Revenues				
Total for Year	0.23	2.18	1.53	1.09
Total since 1979	0.23	7.14	15.80	26.99
Operations and Maintenance Expenses[2]				
Total for Year	0.16	0.90	0.91	0.92
Total since 1979	0.16	3.51	8.00	16.22
Consumer Charges (mills/kWh)				
Average for Year	0.11	0.88	0.53	0.29

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-11

FINANCIAL EFFECTS OF POLLUTION CONTROL EXPENDITURES
BY UNITS COMING INTO SERVICE AFTER 1984:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	0.00	2.85	3.98	7.36
Total since 1979	0.00	3.55	18.99	70.43
External Financing				
Total for Year	0.00	2.55	2.97	7.03
Total since 1979	0.00	6.16	19.32	61.53
Operating Revenues				
Total for Year	0.00	0.06	3.11	10.26
Total since 1979	0.00	(0.36)	9.48	69.96
Operations and Maintenance Expenses[2]				
Total for Year	0.00	0.15	0.97	3.90
Total since 1979	0.00	0.15	3.21	24.70
Consumer Charges (mills/kWh)				
Average for Year	0.00	0.02	1.08	2.74

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-12

FINANCIAL EFFECTS OF FUEL PREMIUMS
FOR UNITS IN EXISTENCE AS OF 1979:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	0.00	0.00	0.00	0.00
Total since 1979	0.00	0.00	0.00	0.00
External Financing				
Total for Year	0.00	0.00	0.00	0.00
Total since 1979	0.00	0.00	0.00	0.00
Operating Revenues				
Total for Year	5.63	5.24	4.76	3.79
Total since 1979	5.63	32.70	57.35	96.45
Operations and Maintenance Expenses[2]				
Total for Year	5.84	5.47	4.97	3.95
Total since 1979	5.84	34.09	59.80	100.52
Consumer Charges (mills/kWh)				
Average for Year	2.65	2.12	1.68	1.00

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-13

FINANCIAL EFFECTS OF ALL POLLUTION CONTROL EXPENDITURES,[1]
EXCLUDING FUEL PREMIUMS, FOR UNITS IN EXISTENCE AS OF 1979:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[2]				
Total for Year	0.00	0.00	0.00	0.00
Total since 1979	0.00	0.00	0.00	0.00
External Financing				
Total for Year	(0.28)	(0.16)	(0.08)	(0.03)
Total since 1979	(0.28)	(1.31)	(1.86)	(2.28)
Operating Revenues				
Total for Year	2.45	2.25	2.11	2.48
Total since 1979	2.45	13.99	24.68	45.00
Operations and Maintenance Expenses[3]				
Total for Year	1.29	1.52	1.77	2.43
Total since 1979	1.29	8.42	16.76	35.69
Consumer Charges (mills/kWh)				
Average for Year	1.15	0.91	0.74	0.67

[1]As defined in this study.
[2]Excludes changes in construction work in progress.
[3]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-14

FINANCIAL EFFECTS OF FUEL PREMIUMS
FOR UNITS COMING INTO SERVICE AFTER 1979,
PLUS COAL CONVERSIONS:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	0.00	0.00	0.00	0.00
Total since 1979	0.00	0.00	0.00	0.00
External Financing				
Total for Year	0.00	0.00	0.00	0.00
Total since 1979	0.00	0.00	0.00	0.00
Operating Revenues				
Total for Year	0.05	0.32	0.44	0.79
Total since 1979	0.05	1.19	3.16	7.76
Operations and Maintenance Expenses[2]				
Total for Year	0.05	0.33	0.46	0.62
Total since 1979	0.05	1.24	3.30	8.10
Consumer Charges (mills/kWh)				
Average for Year	0.02	0.13	0.16	0.17

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-15

FINANCIAL EFFECTS OF SO_2 CONTROLS INSTALLED AFTER 1979
(EXCLUDING SOLID WASTE DISPOSAL COSTS AND FUEL PREMIUMS):
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	1.32	1.64	1.99	3.73
Total since 1979	1.32	8.91	17.40	43.32
External Financing				
Total for Year	2.72	1.19	1.30	3.51
Total since 1979	2.72	8.78	19.77	35.21
Operating Revenues				
Total for Year	0.17	1.75	3.02	6.31
Total since 1979	0.17	5.31	17.95	59.30
Operations and Maintenance Expenses[2]				
Total for Year	0.11	0.72	1.25	2.91
Total since 1979	0.11	2.49	7.61	26.05
Consumer Charges (mills/kWh)				
Average for Year	0.08	0.71	1.05	1.70

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-16

FINANCIAL EFFECTS OF TSP CONTROLS INSTALLED AFTER 1979
(EXCLUDING SOLID WASTE DISPOSAL COSTS):
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	0.88	0.88	0.92	1.70
Total since 1979	0.88	5.68	10.07	21.94
External Financing				
Total for Year	1.81	0.61	0.54	1.58
Total since 1979	1.81	5.41	8.18	17.24
Operating Revenues				
Total for Year	0.04	0.74	1.19	2.23
Total since 1979	0.04	2.01	2.08	22.04
Operations and Maintenance Expenses[2]				
Total for Year	0.00	0.02	0.14	0.56
Total since 1979	0.00	0.02	0.45	3.51
Consumer Charges (mills/kWh)				
Average for Year	0.02	0.30	0.41	0.39

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-17

FINANCIAL EFFECTS OF SOLID WASTE DISPOSAL COSTS
INCURRED AFTER 1979:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	0.25	0.43	0.54	0.98
Total since 1979	0.25	1.85	4.10	10.98
External Financing				
Total for Year	0.56	0.33	0.36	0.91
Total since 1979	0.56	1.93	3.59	9.03
Operating Revenues				
Total for Year	0.08	0.64	1.03	1.85
Total since 1979	0.08	2.15	6.53	19.40
Operations and Maintenance Expenses[2]				
Total for Year	0.07	0.45	0.61	0.97
Total since 1979	0.07	1.67	4.41	11.48
Consumer Charges (mills/kWh)				
Average for Year	0.04	0.26	0.35	0.49

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-18

FINANCIAL EFFECTS OF WATER POLLUTION CONTROLS
INSTALLED AFTER 1979:
BASE CASE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[1]				
Total for Year	0.28	0.42	0.54	0.96
Total since 1979	0.28	2.01	4.27	11.04
External Financing				
Total for Year	0.57	0.33	0.37	0.88
Total since 1979	0.57	2.05	3.73	8.98
Operating Revenues				
Total for Year	0.02	0.33	0.68	1.47
Total since 1979	0.02	0.95	3.64	13.31
Operations and Maintenance Expenses[2]				
Total for Year	0.01	0.11	0.24	0.59
Total since 1979	0.01	0.35	1.26	4.94
Consumer Charges (mills/kWh)				
Average for Year	0.01	0.13	0.23	0.39

[1]Excludes changes in construction work in progress.
[2]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-19

FINANCIAL EFFECTS OF ALL POLLUTION CONTROL EXPENDITURES:[1]
2 PERCENT GROWTH RATE SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[2]				
Total for Year	2.11	2.03	2.16	4.08
Total since 1979	2.11	13.39	23.49	53.64
External Financing				
Total for Year	4.04	1.20	1.22	1.80
Total since 1979	4.04	11.45	17.35	37.41
Operating Revenues				
Total for Year	8.22	10.29	11.21	14.26
Total since 1979	8.22	54.13	108.22	220.31
Operations and Maintenance Expenses[3]				
Total for Year	7.31	8.17	8.72	9.95
Total since 1979	7.31	46.58	88.98	173.28
Consumer Charges (mills/kWh)				
Average for Year	3.90	4.41	4.36	4.64

[1]As defined in this study.
[2]Excludes changes in construction work in progress.
[3]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

Exhibit VI-20

FINANCIAL EFFECTS OF ALL POLLUTION CONTROL EXPENDITURES:[1]
NO NUCLEAR ADDITIONS AFTER 1989 SCENARIO

(billions of 1982 dollars)

	1980	1985	1990	1999
Changes in Plant In-Service[2]				
Total for Year	2.76	3.40	5.29	8.74
Total since 1979	2.76	18.45	37.49	101.09
External Financing				
Total for Year	5.36	2.29	3.66	7.84
Total since 1979	5.36	16.86	31.26	79.91
Operating Revenues				
Total for Year	8.44	11.27	13.30	21.12
Total since 1979	8.44	58.30	120.29	276.40
Operations and Maintenance Expenses[3]				
Total for Year	7.39	8.61	9.52	13.04
Total since 1979	7.39	48.28	93.69	195.85
Consumer Charges (mills/kWh)				
Average for Year	3.97	4.56	4.65	5.65

[1]As defined in this study.
[2]Excludes changes in construction work in progress.
[3]Excludes nuclear fuel.

Source: PTm(Electric Utilities).

APPENDICES

APPENDIX A

THE ENERGY DATABASE

Appendix A

THE ENERGY DATABASE

The Energy Database is a computerized information system developed by Temple, Barker & Sloane for the U.S. Environmental Protection Agency. The information contained within the data files was obtained from the FERC Form 67s supplied to the Energy Information Administration of the U.S. Department of Energy (EIA, DOE) by electric utility companies.

Because the information was obtained from the FERC Form 67s, certain limitations exist with the data. First, the forms used contained information for 1979; therefore, any anomalies occurring in that year will be reflected in the data. Second, only steam-electric generating plants with a capacity of 25 megawatts or greater are required to file the FERC form. Therefore, smaller sized plants are not represented in the databases.

To validate the information contained in the FERC Form 67s, comparisons were made between the forms and several other sources. These sources included:

- Generating Unit Reference File (GURF), DOE
- Steam Electric Plant Factors, 1979, National Coal Association
- Utility FGD Survey, PEDCo
- Survey of Utility Power Plant Emissions and Fuel Data, ICF, Inc., for EPA
- Cost and Quality of Fuels for Electric Utility Plants, 1980, DOE

Every reasonable attempt has been made to ensure that numbers in the databases fall within ranges already established in other publications.

The Energy Database consists of two sets of computer files. The first set of data contains three computer files describing current generating facilities and their operations. Each of these three files describes a particular set of activities for power plants in the Energy Database. These three files are named after the type of information they contain: "plant file," "boiler file," and "stack file."

- The <u>plant file</u> describes characteristics of the power plants in general. These include the plant's fuel consumption; fuel characteristics, including Btu content, sulfur content, and ash content; characteristics of ash production and handling; and cooling water characteristics. Costs associated with these characteristics are also included. (See Exhibit A-1 for a more detailed description.)

- The <u>boiler file</u> presents characteristics of individual units within each plant. These include unit fuel consumption, stack gas cleaning equipment for each unit, cooling facilities on each unit, and costs and in-service dates for the types of equipment described. (See Exhibit A-2.)

- The <u>stack file</u> describes the stacks used by the individual units, including their height and costs. (See Exhibit A-3.)

The second set of files contains information describing planned plant expansions and equipment changes for the period 1980 to 1984 and fuel use for 1984 and 1989. This set consists of two computer files, one describing future plant level operations and the other describing future unit level operations. These two files are called the "future plant file" and the "future boiler file."

- The <u>future plant file</u> projects for 1979, 1984, and 1989 both fuel consumption, including characteristics of the fuel, and plant-level emissions for air, water, and solid wastes. (See Exhibit A-4.)

- The <u>future boiler file</u> forecasts the units and pollution control equipment to be associated with these units. This file includes the same type of information included in the boiler file but for future periods. (See Exhibit A-5.)

Each of the files described above can be examined independently, and comparisons can be drawn between the plants, the boilers, or the stacks within each file. The files can also be related, however, producing complete profiles of plants within a utility of boilers and stacks within the plants, and of future plans for the plants.

In addition to the five files developed from the FERC Form 67s, another file concerned with plant emissions data was also built.

- The emissions data file contains information describing calculated current emissions and allowable emissions for sulfur dioxide and total suspended particulates on a unit-level basis. Also included are the ratios of calculated to allowable emissions for both SO_2 and TSP. (See Exhibit A-6.)

The emissions data file was developed from the ICF report Review of Calculated and Allowable Emissions for Exising Utility Steam Powerplants, prepared for EPA in October 1980.

An additional capability of the Energy Database is its compatability with other databases already developed. Its files of this system can be matched with other databases to supplement the information in each. For the analysis of this study, the databases were matched frequently with the computerized DOE Generating Unit Reference File for both validation requirements and additional information.

The capabilities of the Energy Database can be seen in the chapters of this report. Data for the unit level, regional, and national analyses were supplied, primarily, by the Energy Database.

Exhibit A-1

Data File Name: PLANT.FILE

Item Name	Description
PLANT.CODE	Plant code of plant in question; provides relational key to other files in system.
UTILITY.CODE	First six numbers of the PLANT.CODE through which particular utilities can be selected.
UTILITY.NAME	Name of the utility that operates the plant.
PLANT.NAME	Plant name.
COUNTY	County in which the plant is located.
STATE	State in which the plant is located.
FED.REGION	Federal region in which the plant is located.
COAL.CONSUMPT	Amount (in 1000 tons) of coal consumed by all units in the plant.
COAL.BTU	Average Btu content (in Btu per pound) of coal consumed by plant.
COAL.%.SULFUR	Average sulfur content (in percent by weight) of coal consumed by plant.
COAL.%.ASH	Average ash content (in percent by weight) of coal consumed by plant.
OIL.CONSUMPT	Amount (in 1000 bbls) of oil consumed by all units in the plant.
OIL.BTU	Average Btu content (in Btu per gal.) of oil consumed by the plant.
OIL.%.SULFUR	Average sulfur content (in percent by weight) of oil consumed by the plant.

Exhibit A-1 (continued)

Item Name	Description
GAS.CONSUMPT	Amount (in 1000 mcf) of gas consumed by all units in the plant.
GAS.BTU	Average Btu content (in Btu per c.f.) of gas consumed by the plant.
TOT.COAL.BTU	Total Btu released by coal consumption in millions of Btu (equals COAL.CONSUMPT * COAL.BTU * 2).
TOT.OIL.BTU	Total Btu released by oil consumption in millions of Btu (equals OIL.CONSUMPT * .042 OIL.BTU).
TOT.GAS.BTU	Total Btu released by gas consumption in millions of Btu (equals GAS.CONSUMPT * GAS.BTU).
FLY.TOTAL	Total amount of fly ash resulting from combustion (in 1000 tons).
FLY.SOLD	Amount of fly ash sold (in 1000 tons).
FLY.PD.DISP	Amount of fly ash disposed of by contractors off site (in 1000 tons).
BOT.TOTAL	Amount of bottom ash resulting from combustion (in 1000 tons).
BOT.SOLD	Amount of bottom ash sold (in 1000 tons).
BOT.PD.DISP	Amount of bottom ash disposed of by contractors off site (in 1000 tons).
FLY.$	Cost of fly ash collection and disposal (in $1000).
BOT.$	Cost of bottom ash collection and disposal (in $1000).
TOT.AIR.EXP	Total air quality control expenses (includes fly ash collection and disposal, bottom ash collection and disposal, collection of other products from flue gas, and other air quality expenses (in $1000)).

Exhibit A-1 (continued)

Item Name	Description
AVG.DISCHARGE	Average annual rate of discharge of cooling water to a water body (in c.f.s.).
WINTER.OUTFALL	Maximum temperature of cooling water at outfall during winter season (in ^{o}F).
WINTER.AVG.FLOW	Average winter monthly flow of cooling water to a receiving water body (in c.f.s.).
SUMMER.OUTFALL	Maximum temperature of cooling water at outfall during summer season (in ^{o}F).
SUMMER.AVG.FLOW	Average summer monthly flow of cooling water to a receiving water body (in c.f.s.).
CHLORINE	Amount of chlorine added to cooling water during year (in lbs).
PLANT.O.M.	Annual operation and maintenance expenses for the cooling water operation at the plant (in $1000).
CHEM.COST	Annual cost of chemical additions to cooling water at plant (in $1000).
BOILER.CHEM	Annual cost of chemical additions to boiler water makeup and boiler blowdown treatment (in $1000).
MAX.OUTFALL.TEMP	Maximum allowable temperature of cooling water at outfall: summer (in ^{o}F).
MAX.TEMP.WINTER	Maximum allowable temperature of cooling water at outfall: winter (in ^{o}F).
DISCHARGE.VOL	Total discharge of bottom ash to settling pounds (in c.f./year).
SEWAGE.CODE	Code for plant sewage disposal.

Exhibit A-2

Data File Name: BOILER.FILE

Item Name	Description
PLANT.CODE	Plant code of the plant in which the unit is located.
BOILER.NO	Boiler number of this unit.
FUEL.COAL	Amount of coal consumed by unit (in 1000 tons).
FUEL.OIL	Amount of oil consumed by unit (in 1000 bbls).
FUEL.GAS	Amount of gas consumed by unit (in 1000 mcf).
CAPACITY.	Capacity factor of unit.
STACK.NO	Number of the stack associated with the unit.
WET.DRY	Wet or dry bottom.
FIRING	Type of firing.
COAL OIL GAS	Code identifies whether the unit is able to burn alternate fuel.
FGC	Type of FGC (flue gas cleaning) equipment associated with unit.
FGC.EFF	Removal efficiency of the FGC equipment.
FGC.INSERV	In-service year of FGC equipment.
FGC.Cost	Cost of FGC equipment (in $1000).
ESP.	Type of ESP (electrostatic precipitator) associated with unit.
ESP.EFF	Removal efficiency of the ESP equipment.

Exhibit A-2 (continued)

Item Name	Description
ESP.INSERV	In-service year of ESP equipment.
ESP.COST	Cost of ESP equipment (in $1000).
FGD	Type of FGD (flue gas desulfurization) equipment associated with unit.
FGD.EFF	Removal efficiency of FGD equipment.
FGD.INSERV	In-service year of FGD equipment.
FGD.COST	Cost of FGD equipment (in $1000).
CAPACITY.MW	Rated generating capacity of the unit in megawatts.
COOL.TYPE	Type of cooling facilities associated with unit.
YR.INST	Year cooling facilities were installed.
OTC.COST CP.COST CT.COST	Cost of cooling facilities associated with the unit--OTC, once-through cooling; CP, cooling pond; CT, cooling tower (in $1000).
SOURCE.OTC	Name of water source if unit uses once-through cooling facilities.
SOURCE.CP	Name of water source if unit uses cooling ponds.
BOILER.YR	In-service date of the unit.
KWH	Generation for 1979 for the unit.

Exhibit A-3

Data File Name: STACK.FILE

Item Name	Description
PLANT.CODE	Plant code of the plant in which the stack is located.
STACK.NO	Number of the stack.
COST	Cost of the stack (in $1000).
HEIGHT	Height of the stack (in feet).

Exhibit A-4

Data File Name: FUTURE.PLANT.FILE

Item Name	Description
PLANT.CODE	Plant code of plant in question.
PLANT.NAME	Plant name.
COAL.CONS.84 COAL.CONS.89 COAL.BTU.84 COAL.BTU.89 COAL.%S.84 COAL.%S.89	Projected coal consumption (in 1000 tons), Btu content (in Btu/lb), and sulfur content (in percent by weight) of the coal for 1984 and 1989.
RES.OIL.CONS.84 RES.OIL.CONS.89 RES.OIL.%S.84 RES.OIL.%S.89	Projected residual oil consumption (in 1000 bbls) and average sulfur content (in percent by weight) of the oil for 1984 nd 1989.
DIS.OIL.CONS.84 DIS.OIL.CONS.89	Projected distillate oil consumption (in 1000 bbls) for 1984 and 1989.
CR.OIL.CONS.84 CR.OIL.CONS.89 CR.OIL.%S.84 CR.OIL.%S.89	Projected crude oil consumption (in 1000 bbls) and average sulfur content (in percent by weight) of oil for 1984 and 1989.
GAS.CONS.84 GAS.CONS.89	Projected gas consumption (in 1000 mcf) for 1984 and 1989.
TOT.TSP.79 TOT.TSP.84 TOT.TSP.89	Projected total particulate emissions (in 1000 tons/year) for 1979, 1984, and 1989.
TOT.SOX.79 TOT.SOX.84 TOT.SOX.89	Projected total sulfur oxide emissions (in 1000 tons/year) for 1979, 1984, and 1989.
TOT.NOX.79 TOT.NOX.84 TOT.NOX.89	Projected total nitrogen oxide emissions (in 1000 tons/year) for 1979, 1984, and 1989.

Exhibit A-4 (continued)

Item Name	Description
OTC.%.84 OTC.%.89 WCT.%.84 WCT.%.89 DCT.%.84 DCT.%.89 CP.%.84 CP.%.89	Percent of capacity cooled by the following types of cooling facilities for 1984 and 1989: OTC--once-through cooling; WCT--wet cooling tower; DCT--dry cooling tower; CP--cooling pond.
AVG.WITHDL.84 AVG.WITHDL.89	Projected average water withdrawal from water body (in c.f.s.) for 1984 and 1989.
AVG.T.RISE.84 AVG.T.RISE.89	Projected average temperature across condensers (in ^{o}F) for 1984 and 1989.
AVG.RETURN.84 AVG.RETURN.89	Projected average water return to water body (in c.f.s.) for 1984 and 1989.
TOT.ASH.84 TOT.ASH.89	Projected total top and bottom ash (in 1000 tons/year) for 1984 and 1989.
STACK.WASTE.84 STACK.WASTE.89	Projected stack scrubbing waste (in 1000 tons/year) for 1984 and 1989.
FGD.REGEN	Is the FGD system regenerable?

Exhibit A-5

Data File Name: FUTURE.BOILER.FILE

Item Name	Description
PLANT.NAME	Plant name.
PLANT.CODE	Plant code of plant in which the unit is located.
BOILER.NO	Boiler number of planned unit.
NU.STACK.NO	Stack number of planned unit.
NU.MW.CAPACITY	Capacity of planned unit (in megawatts).
NU.INSERV	In-service date of planned unit.
NU.COAL.PER.HR	Coal consumption of planned unit (in tons/hour).
NU.OIL.PER.HR	Oil consumption of planned unit (in bbls/hour).
NU.GAS.PER.HR.	Gas consumption of planned unit (in 1000 c.f./hour).
NU.OTHER.FUEL	Consumption of other fuels of the planned unit.
NU.PRIM.FUEL	Primary fuel to be fired in planned unit.
NU.BOTTOM	Wet or dry bottom of planned unit.
NU.FIRING	Type of firing of planned unit.
FUEL.TYPE	Fuel type (of existing or planned unit).
BOILER.CAT	Code describing the type of boiler being reported.
TSP.REG	Limiting TSP regulation; federal, state, or local requirement.

Exhibit A-5 (continued)

Item Name	Description
NEWBOIL.TSPCOD	Units of TSP requirement (e.g., lb in Btu, lb/hour, or grains/standard cubic foot).
NEWBOIL.TSPLIM	Actual TSP requirement in above units.
TSP.STRATEGY	Strategy for meeting TSP requirement.
SOX.REG	Limiting SOX regulation; federal, state, or local requirement.
NEWBOIL.SOXCOD	Units of SOX requirement.
NEWBOIL.SOXLIM	Actual SOX requirement in above units.
SOX.STRATEGY	Strategy for meeting SOX requirement.
PREC.BOILER.CAT	Code describing boiler and its relation to a TSP system.
PREC.STACK.NO	Stack associated with TSP equipment.
PREC.RETRO	Will particulate equipment be retrofit?
PREC.TYPE	Type of particulate removal equipment to be installed (for planned or existing equipment).
PREC.INSERV	In-service date of particulate equipment.
PREC.FUEL.DSN	Type of fuel particulate equipment is designed to handle.
PREC.%.S.DSN	Percent sulfur fuel specification for particulate equipment.
PREC.%.ASH.DSN	Percent ash fuel specification for particulate equipment.
PREC.EFFIC	Particulate equipment design removal efficiency.

Exhibit A-5 (continued)

Item Name	Description
PREC.MER	Particulate equipment's designed mass emission rate.
PREC.EQ.COST	Equipment and installation cost ($/kWh) for particulate equipment.
TOT.PREC.COST	PREC.EQ.COST plus other capital costs ($/kWh).
PREC.ENERGY.OM	Operating and maintenance expense associated with energy for the particulate control equipment.
PREC.WASTE.OM	Operating and maintenance expense associated with waste disposal for the particulate control equipment.
PREC.TOT.OM	Total operating and maintenance expense associated with the particulate control equipment (includes PREC.ENERGY.OM and PREC.WASTE.OM).
FGD.BOILER.CAT	Code describing boiler and its relation to a FGD system.
FGD.STACK.NO	Stack associated with FGD equipment.
FGD.TYPE	Type of FGD equipment to be installed on existing or planned units.
FGD.SCRUB	Wet or dry scrubbing.
FGD.INSERV	Date of commercial operation of the FGD equipment.
FGD.CAPACITY	FGD unit capacity (in megawatts).
FGD.%S.DSN	Percent sulfur in fuel for which the FGD unit was designed.
FGD.%ASH.DSN	Percent ash in fuel for which the FGD unit was designed.
FGD.%CHL.DSN	Percent chlorine in fuel for which the FGD unit was designed.

Exhibit A-5 (continued)

Item Name	Description
%GAS.TREATED	Percent of total gas which passes through the FGD equipment.
FGD.BYPASS	Capability to bypass the FGD equipment.
FGD.DSN.EFF	Design removal efficiency (percent by weight of SO_2 removed) of FGD unit.
FGD.ACT.EFFIC	Actual removal efficiency (percent by weight of SO_2 removed) of FGD unit.
WITHPREC.EFFIC	Removal efficiency if particulate scrubber included on unit.
FGD.DSN.MER	FGD design mass emission rate.
FGD.LIFE	Estimated useful life of the FGD unit.
SLDG.DISP	Sludge disposal: on or off site.
SLDG.STABLE	Is sludge stabilized?
POND.REQ	Pond or landfill requirements (in acre-feet/year).
POND.LINED	Is the sludge pond lined?
FGD.INST.COST	Installed capital cost of the FGD unit (in $/kWh).
FGD.ANCIL	Installed capital cost of ancillaries (in $/kWh).
SLDG.DSP.COST	Capital costs for sludge disposal site preparations and waste transport system (in $/kWh).
SYS.REV	Revenue from sale of regenerable product (in $/kWh).
REG.SYS.COST	Installed capital cost of regenerable system (in $/kWh).

Exhibit A-5 (continued)

Item Name	Description
FGD.OTHER.COST	Other capital costs for FGD system (in $/kWh).
WASTE.OPER.COST	The waste disposal component of operating expenses for the FGD unit (in $/kWh).
FGD.TOT.OP.CST	Total operating expenses attributable to the FGD unit (in $/kWh).
FGD.TOT.MNTC	Total maintenance expenses attributable to the FGD unit (in $/kWh).
FGD.ELEC.DEM	Electrical demand by the FGD unit (in kWh/h).
FGD.REHEAT.DEM	Reheat electrical demand equivalent (in kWh/h).
FGD.SCRUB.HRS	Hours of scrubber operation.
FGD.AVG.CAPACITY	Average scrubber capacity during the year (in MW).
FGD.FOR	Number of hours during the year that the boiler was forced out of service due to an FGD system outage.
FGD.FOR.CAPACITY	Average outage capacity level (in MW).
FGD.RED.LD	Number of hours during the year that the boiler was forced to operate at a reduced load due to FGD system limitations.
FGD.RED.LD.CAP	Average load reduction capacity level.

Exhibit A-6

Data File Name: EMISSIONS.DATA.FILE

Item Name	Description
PLANT.CODE	Plant code of plant in which the unit is located.
UNIT.NO	Boiler number of unit.
FUEL.TYPE	Emissions for unit associated with burning this type of fuel (coal, oil, gas).
SO2.CALC.EM	Unit's calculated SO_2 emission given fuel consumption (1,000 tons).
TSP.CALC.EM	Unit's calculated TSP emission given fuel consumption (1,000 tons).
SO2.ALLOW.EM	Allowable SO_2 emission for unit under current regulations (1,000 tons).
TSP.ALLOW.EM	Allowable TSP emission for unit under current regulations (1,000 tons).
SO2.RATIO	Ratio of calculated to allowable emissions for the unit.
TSP.RATIO	Ratio of calculated to allowable emissions for the unit.

APPENDIX B

PTm(ELECTRIC UTILITIES)
RESEARCH METHODOLOGY

Appendix B

PTm(ELECTRIC UTILITIES) RESEARCH METHODOLOGY

This appendix on research methodology consists of a non-technical overview of the logical structure of the computer model, PTm(Electric Utilities), used to derive the projections discussed and analyzed in the text of this report. In broad terms, PTm has three main logical components, which may conveniently be labeled the external, physical, and financial modules. As shown in Exhibit B-1, it is assumed that general economic conditions and other factors outside the model determine the demand for electricity. Expectations regarding future generation expansion plans, and the equipment, power drain, and generating efficiency implications of pollution control requirements, combine to determine the industry's physical plant, equipment, fuel, and labor requirements. These physical requirements and the relevant factor costs, which are also influenced by economic considerations external to PTm, combine to determine the consequences of building and operating the capacity.

The capital asset and operating cash requirements implied by the capacity expansion plan are met in part by revenues collected from the users of electrical energy and in part by external financing. The amount of cash provided by operations at any moment is influenced by regulatory policy (in effect via the allowed revenue per kilowatt-hour), by tax policy (via the effective rate of taxation after consideration of depreciation tax shields, investment tax credits, etc.), and by the cost of capital raised in prior periods. Any shortfall between cash needs and the cash provided by operations is met by recourse to the capital markets.

Exhibit B-1 omits a number of interactions and feedbacks, two of which are notable. First, if external financing is to be available, regulatory policy must be such as to allow revenues per kilowatt-hour sufficient to yield returns to capital that are adequate in light of prevailing capital market conditions, tax policy, and pollution control requirements, all of which may have an impact on the cost of electrical power and hence on demand. As a second illustration, because the financial characteristics of the electric utility industry and of individual utilities may be considered in the drafting and administration of pollution control legislation, pollution control policy in part determines and in part is determined by the industry's financial profile.

EXTERNAL MODULE

The model's external module has as its primary function the inputting of assumptions, such as those concerning future growth in generating capacity, operating costs, future pollution control requirements, etc. The implications of these policy, economic, and technical assumptions are then determined in the physical and financial modules of PTm. PTm is programmed so as to be able to test a wide variety of policy alternatives through changes in input data.

PHYSICAL PLANT AND EQUIPMENT MODULE

The primary relationships determining the industry's physical plant and equipment requirements are shown in Exhibit B-2. The industry's gross generating capacity in service at any moment is typically determined by the level of demand, the industry's policy with respect to capacity reserves, and the effect of pollution control equipment and in-plant power requirements. However, for consistency with another recent study for EPA, PTm was modified to accept projections of future capacity additions and retirements as direct inputs. With the inclusion of the pollution control equipment required for generating capacity currently in service, the additions to in-service plant and related equipment are fully specified in physical terms.

Given the long time lags involved in constructing new generating capacity, the industry's plant and equipment construction at any moment typically includes significant amounts of work in progress. As is shown in Exhibit B-2, future capacity additions and future pollution control requirements--together with the lags in construction--determine plant construction in progress. It should be noted that because the time span between ordering and placing generating capacity in service is radically different for hydro facilities, peaking units, fossil-fueled baseload plants, and nuclear units, PTm computes construction work in progress for plants by fuel type on different time schedules. Thus average construction lags are themselves a function of the assumed future mix of these various types of generating plants.

FINANCIAL MODULE

For expositional purposes it is convenient to divide PTm's financial modules into three segments, dealing with:

- Uses of funds,
- Sources of funds, and
- Revenues and related variables.

Uses of Funds

The industry's uses of funds depicted in Exhibit B-3 are determined primarily by the physical plant and equipment required to meet current and future demand and by the cost per unit of this equipment. A second use is the allowance for funds tied up in plant and equipment in the process of construction. For simplicity, PTm assumes that the industry's net working capital remains constant, so that changes in working capital appear neither as a use nor as a source of funds. Given the minuscule size of such working capital changes in comparison with the industry's major sources and uses of funds, such a simplifying assumption is unlikely to introduce appreciable error in the absence of fundamental structural changes in the industry's current assets and payables accounts or in its usage of short-term debt.

Exhibit B-3 shows that once the total physical amounts of plant and equipment required to meet current and future demand and the proportions of those amounts accounted for by each type of new capacity are determined, the crucial input assumptions required to convert these physical quantities into financial terms are the cost per unit of each type of asset and the schedule of payments required by contractors while such plant and equipment are under construction.

Sources of Funds

In the case of the private sector of the electric utility industry, sources of funds consist of two major elements:

- Funds provided by operations, and
- External financing.

Funds provided by operations are in turn the sum of three internal sources:

- Depreciation,
- Tax deferrals, and
- Retained earnings.

For the public sector, it is simply assumed that a percentage of total funds used is met from internal sources. As is shown in Exhibit B-4A, any shortfall between total uses and internal sources is met through external financing.

Exhibit B-4B shows these same relationships in a format that is slightly different and that shows how the private sector's total required external financing, capital structure, and dividend policies combine to determine:

- Cash issues of preferred stock,
- Gross cash offerings of debt, and
- Cash issues of common stock.

Revenues and Related Variables

The third segment of the financial module determines total industry revenues, expenses, profits, and related statistics such as price per kilowatt-hour and interest coverage ratios. The output variables of this revenues segment serve in many instances as inputs to other segments. For example, the depreciation expense figure computed in the revenue segment is an input to the sources of funds segment. Conversely, certain of the input variables to the revenue segment are based on the output from the sources and uses segment of the financial module (e.g., plant and equipment expenditures provide the base for computing depreciation expense). The structure of the revenue segment and the interactions between this segment and other parts of the total model are depicted in Exhibit B-5.

As shown at the top of Exhibit B-5, profits available for common stockholders are assumed to be determined completely by the amounts of the industry's common equity capital and by a rate of return on equity set by regulatory policy.[1] As a consequence of this assumption, revenues and prices per kilowatt-hour of electricity are determined by required profits, other capital charges, and operating expenses.

Earnings before interest and taxes (EBIT) are simply the sum of earnings before interest taxes (EBT) and interest expense and are computed by the same general process used for preferred dividends. The resultant EBIT figure constitutes one of the five main determinants of revenues.

The second determinant of revenues, depreciation and amortization of plant and equipment, is a variable related to the amount of plant and equipment in service. Presuming that taxes other than on income consist primarily of property taxes, a third determinant of revenue, other taxes, is also related to the amount of plant and equipment in service.

Generation expansion plans and the power drains and operating efficiency losses associated with pollution control equipment combine to determine the level of operating and maintenance expenses. This latter expense figure is the fourth determinant of revenues.

Generation expansion plans and pollution control requirements also determine the timing of future in-service plant and equipment requirements and hence determine the amount of construction currently in progress. The amount of construction in progress in turn determines the allowance for funds used during construction, which is another non-cash item, but which also affects--in this case diminishes--the level of revenues required to achieve a given level of profit as determined by regulatory accounting procedures. This allowance on construction funds variable is the fifth and last major determinant of revenues.

Net profit is simply the sum of profits available for common stock and preferred dividends. The amounts of preferred dividends are determined by the amounts of preferred equity capital and the average dividend rate on the industry's

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[1] It should be noted that "policy" is a term intended to comprise the effect of both the target rates of return set by individual regulatory bodies and the administrative lags involved in adjusting prices per kilowatt-hour so as to achieve such target returns.

outstanding preferred stock. The dividend yield on new preferred stock issues--and hence the average yield--is in turn determined over time by the reaction of the capital market to the industry's offerings.

Earnings before income taxes are then set at a level such that EBT minus taxes will be equal to the required net profit figure. The tax expense (or equivalently, the effective tax rate) is itself a function of the EBT figure, which is computed in accordance with regulatory accounting procedures, and several other factors. The calculations are somewhat complicated first because various special features of the tax code (e.g., provisions allowing investment tax credits and accelerated depreciation) and of regulatory accounting (e.g., the creation of allowances for funds used during construction as non-cash credits to income) must be taken into account. As a consequence of these differing provisions, taxable EBT and regulatory EBT may--and typically do--differ. Second, as mentioned earlier, there exist two substantially different regulatory methods for determining the tax expense figure to be associated with EBT. Normalizing accounting gives rise to deferred taxes, which are non-cash charges against income but which nonetheless constitute an accounting expense to be covered by revenues if accounting profits to stockholders are to reach prescribed levels.

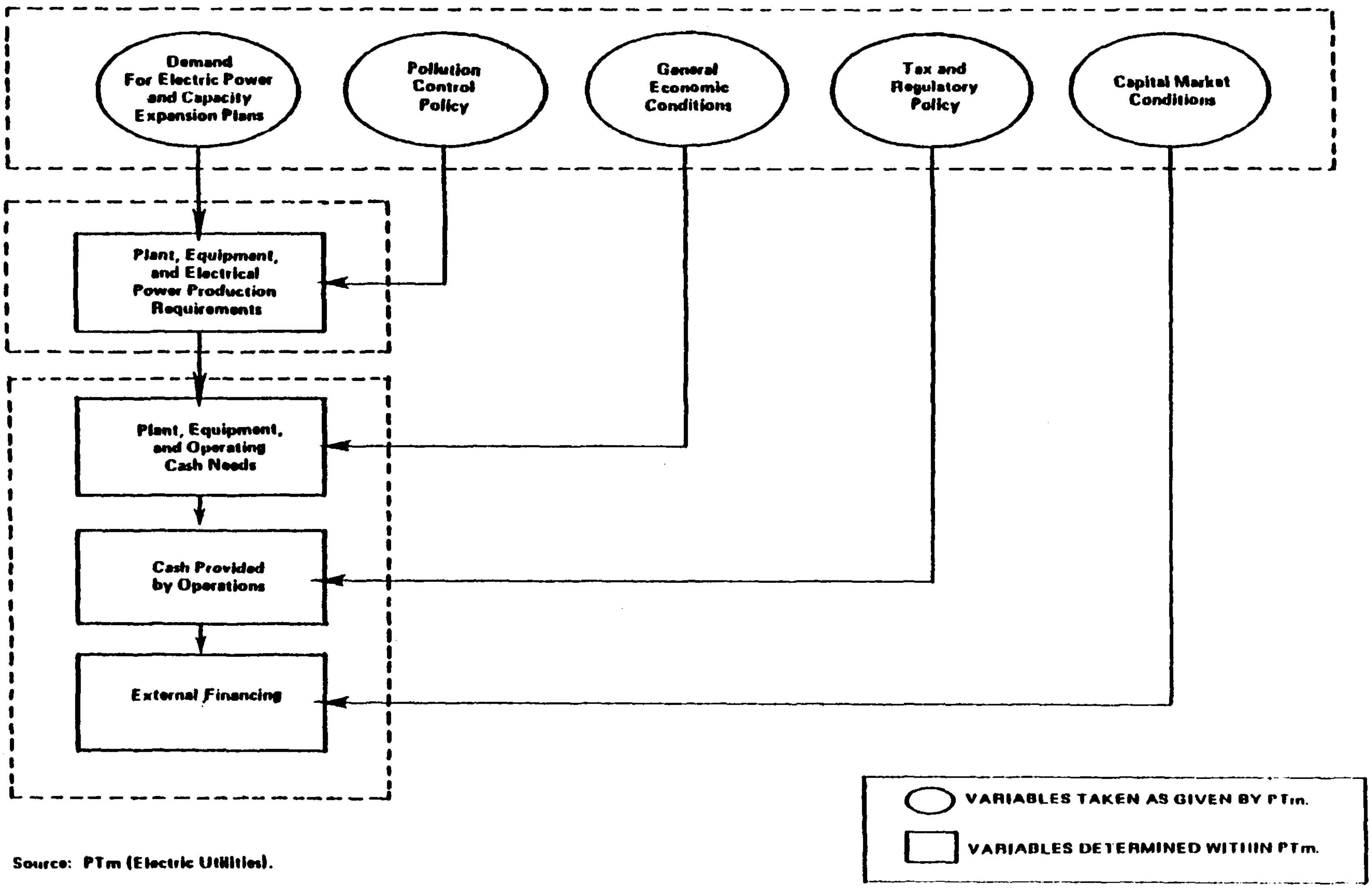
A CONCLUDING COMMENT

As has been outlined above, the operating, financial, tax, regulatory, and accounting relationships and constraints relevant to making economic and financial projections for the industry are individually rather simple. However, the number of these relationships and constraints is so great as to dictate the use of a computer model such as PTm. Moreover, because of interactions among the various industry relationships and constraints, attempts to reduce the number of factors through shortcut approximations are hazardous. Furthermore, such shortcuts, even if based on careful econometric analyses of historical data, tend to preclude an examination of the implications of structural and policy changes.

PTm was designed not only to compute rapidly the implications of any given set of assumptions about the future, but also to facilitate the examination of structural and policy changes. Thus, the model is able conveniently to accept input assumptions for over 100 variables, such as the current level of and future changes in: the industry's peak demand; the amount and mix of capacity additions; unit costs of generating plants, transmission and distribution capacity, thermal and chemical pollution equipment, etc. PTm then generates projections for a variety of physical and financial variables, including: generation figures for each of the major fuel segments of the industry; energy losses resulting from pollution control equipment; income statements; balance sheets; funds flows; reconciliations of regulatory and Internal Revenue Service income tax expense figures; and summary statistics such as interest coverage figures.

Exhibit B–1

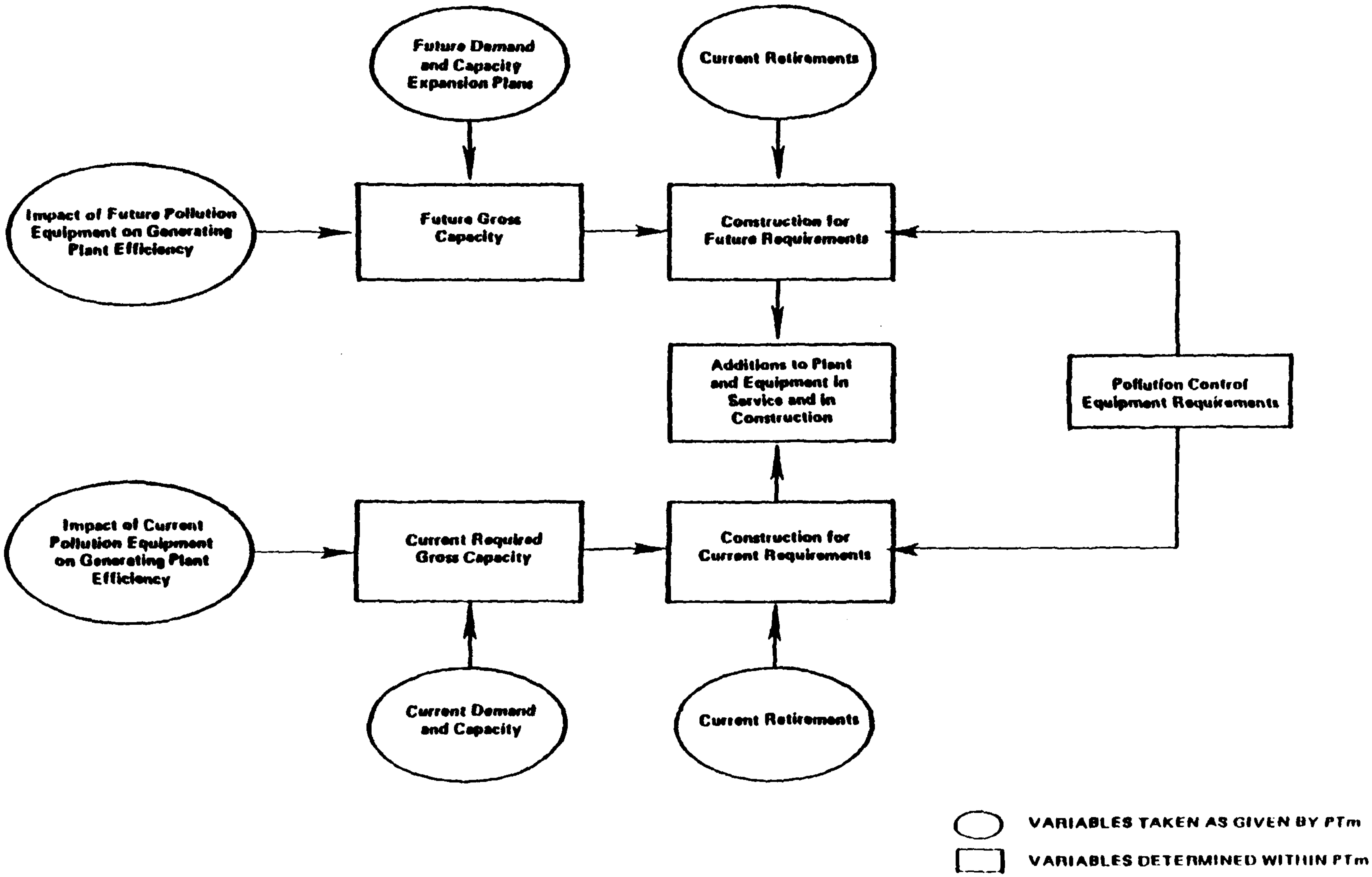
INTERACTIONS BETWEEN THE ENVIRONMENT AND THE PHYSICAL AND FINANCIAL CHARACTERISTICS OF THE ELECTRIC UTILITY INDUSTRY



Source: PTm (Electric Utilities).

Exhibit B–2

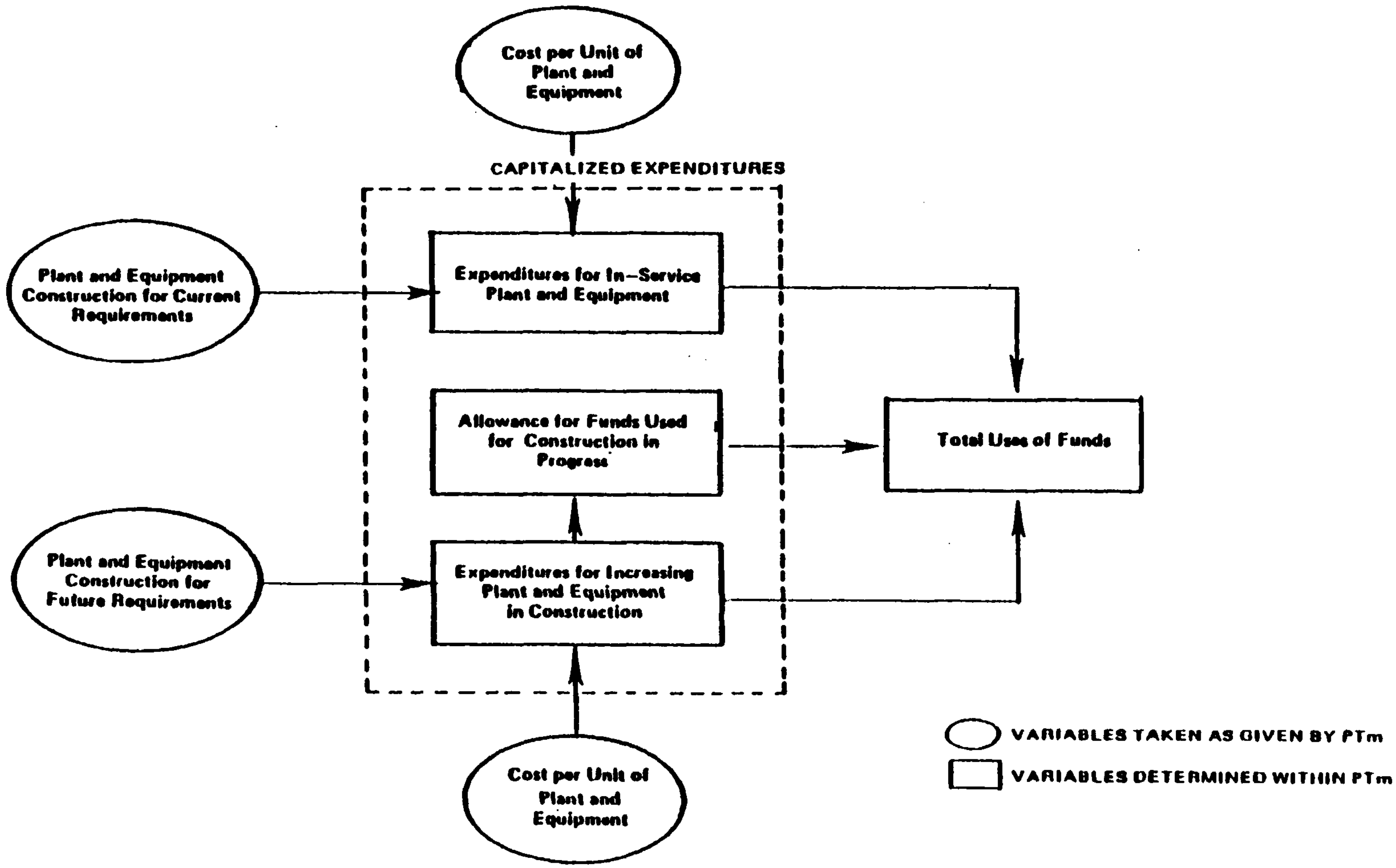
DETERMINANTS OF PLANT AND EQUIPEMENT IN SERVICE AND IN CONSTRUCTION FOR THE ELECTRIC UTILITY INDUSTRY



Source: PTm (Electric Utilities).

Exhibit B–3

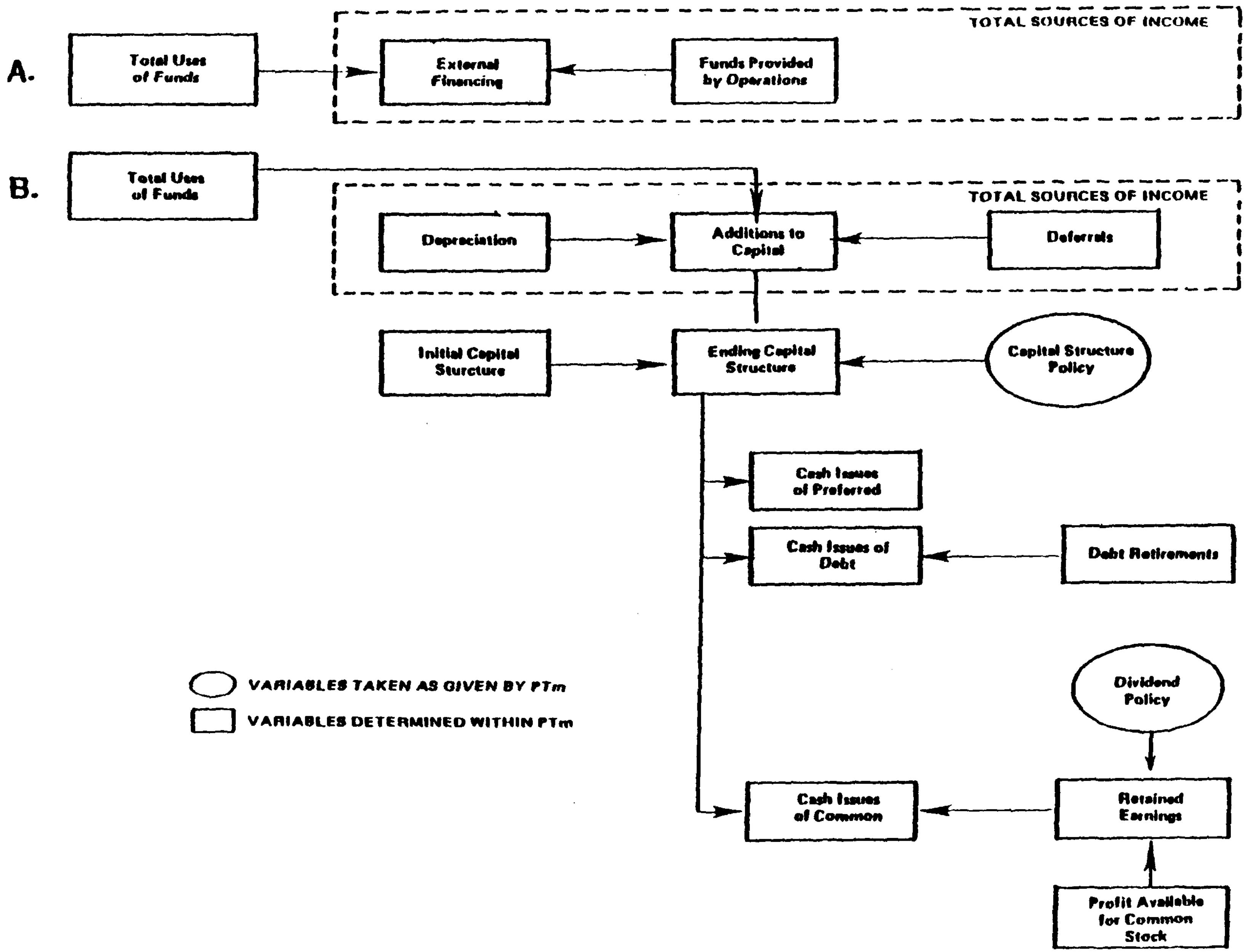
DETERMINANTS OF USES OF FUNDS FOR THE ELECTRIC UTILITY INDUSTRY



Source: PTm (Electric Utilities).

Exhibit B–4

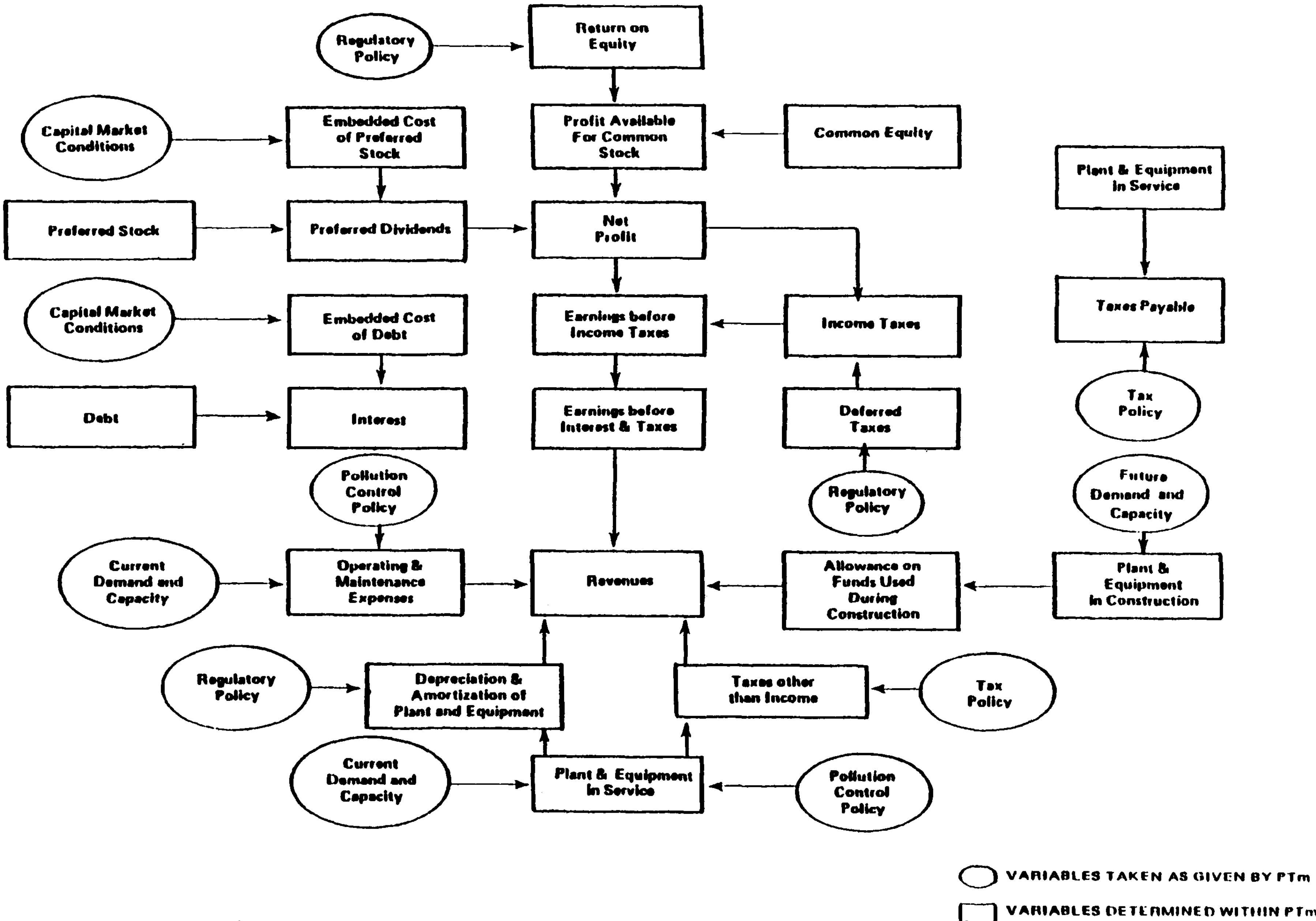
DETERMINANTS AND COMPOSITION OF TOTAL SOURCES OF FUNDS FOR THE ELECTRIC UTILITY INDUSTRY



Source: PTm (Electric Utilities).

Exhibit B–5

DETERMINANTS OF REVENUES, EXPENSES, AND PROFITS FOR THE ELECTRIC UTILITY INDUSTRY



Source: PTm (Electric Utilities).

APPENDIX C

CAPITAL EXPENDITURES AND ELECTRIC UTILITY ACCOUNTING PROCEDURES

Appendix C

CAPITAL EXPENDITURES AND ELECTRIC UTILITY ACCOUNTING PROCEDURES

In Chapter VI "changes to plant in-service" or "plant additions" are used as a measure of the total capital costs associated with electric utility expansion plans. This appendix contrasts the definition of plant in-service used in this study with the definition typically used in the industry and relates those definitions to other commonly used measures of capital costs. One of the major issues in accounting for capital costs is the treatment of the financing costs associated with the cash outlays for construction work in progress (CWIP). The second section of this appendix reviews the major accounting methods used to recover financing costs and provides a brief summary of the cash flow and balance sheet effects of these methods.

DEFINITIONS OF PLANT IN-SERVICE AND CAPITALIZED EXPENDITURES

Changes in plant in-service, as defined for this study, represent total cash outlays for plant construction during the year, minus the year-to-year change in the cash amounts in the CWIP account, plus the carrying charges on the past cash outlays still in the CWIP account (allowance for funds used during construction--AFDC). As discussed further below, the PTm computer model used for this study transfers AFDC directly to the plant in-service account in the year in which it is accrued, rather than in the year the equipment is actually placed in service. This differs from the typical industry practice, which retains this AFDC balance in the CWIP account until the associated cash portion of the construction expenditures is transferred to the plant in-service account.

Additions to plant in-service, using either PTm's definition or the industry's typical definition, differ from another common measure of capital costs, namely capitalized expenditures. Total capitalized expenditures typically refer to total cash outlays and capital-carrying costs incurred during a given period. Capitalized expenditures differ from changes in plant in-service to the extent that beginning CWIP balances do not equal ending CWIP balances. Capitalized expenditures include costs (both cash outlays and financing costs) for equipment not yet placed in service. Plant in-service excludes costs associated with ongoing construction, except that PTm does include in the plant in-service account the financing costs associated with CWIP balances.

TREATMENT OF FINANCING COSTS

Cash outlays for construction of new equipment are credited to either the plant in-service account, for outlays associated with equipment placed into service in the current period, or to the CWIP account, for outlays associated with equipment that will not be placed into service until some future period. Those cash outlays placed in the CWIP account accrue capital-carrying charges which must be recovered.

There are two principal ratemaking methods used to account for capital-carrying costs. The first method, the AFDC approach, treats capital costs as part of the cost of the project. This is the most common approach used in the industry, and is the approach adopted for this study. During the period of construction, the allowance is included as a credit to "other income" on the income statement. The amount of the credit represents an estimate of capital-carrying charges associated with financing construction expenditures. This credit to other income is an accounting entry only and does not represent cash earnings in the current period. Instead, the AFDC credit represents a non-cash credit to earnings; it in effect replaces revenues collected from customers in terms of offsetting financing costs. The capital costs accumulated over the construction period are included in the rate base once the plant or equipment is placed into service and are recovered over the useful life of the asset through financing and depreciation charges. For the purposes of the PTm analysis used in this study, the rate base is assumed to equal the dollar value of the plant in-service account.

The second method, allowing CWIP in the rate base, considers construction expenditures as part of the rate base when they are made. Consumer rates, then, reflect capital-carrying costs during the construction period. Allowing CWIP in the rate base may be characterized as a "pay-as-you-go" treatment for capital-carrying costs. Unlike the AFDC credit to earnings, allowing CWIP in the rate base results in revenues and cash earnings (as opposed to non-cash earnings associated with the AFDC credit).

Figure C-1 demonstrates the differences in the two accounting methods in terms of the effect on rate base, revenues, and earnings. The left-hand side of the diagram shows the treatment of cash outlays associated with equipment that is placed into service in the current period. The right-hand side of the diagram shows the treatment of cash outlays for equipment that will not be placed into service until some future period. As indicated in Figure C-1, cash outlays for CWIP when CWIP is included in the rate base have much the same impact on revenues as cash outlays for equipment placed into service in the current period. The AFDC method, on the other hand, does not increase rate base or revenues effects in the year AFDC is created. The AFDC credit represents a non-cash earnings offset to be included in plant in-service and in the rate base when the equipment is eventually placed into service.

A number of financial changes occur when CWIP is allowed in the rate base. Consumer rates rise initially, relative to AFDC treatment, since capital-carrying charges during construction are reflected in consumer rates immediately rather than over the useful life of the asset. On the other hand, external financing requirements are lower because capital-carrying costs need not be financed and the cash flow available to meet interest and dividends increases. Moreover, when CWIP is allowed in the rate base, total financing costs are lower because total assets are lower and because the capital cost rates required by investors can be expected to be lower.

The analysis presented in this study assumes a continuation of the general industry practice of using the AFDC approach. However, PTm does not track the in-service dates of individual units and therefore the unit-specific AFDC. As a consequence, AFDC associated with a particular project cannot be identified and included in the rate base at the time the unit comes on-line. The model instead computes total CWIP balances and determines the AFDC associated with those balances. AFDC is allocated directly to the plant in-service account, while CWIP, excluding the associated AFDC portion, is transferred to the plant in-service account in the year the corresponding capacity is operational. Figure C-2 demonstrates the differences between the industry method of accounting for financing charges associated with construction expenditures under the AFDC approach and the logic used in PTm.

Figure C-1

ACCOUNTING TREATMENT OF CASH OUTLAYS
FOR NEW EQUIPMENT

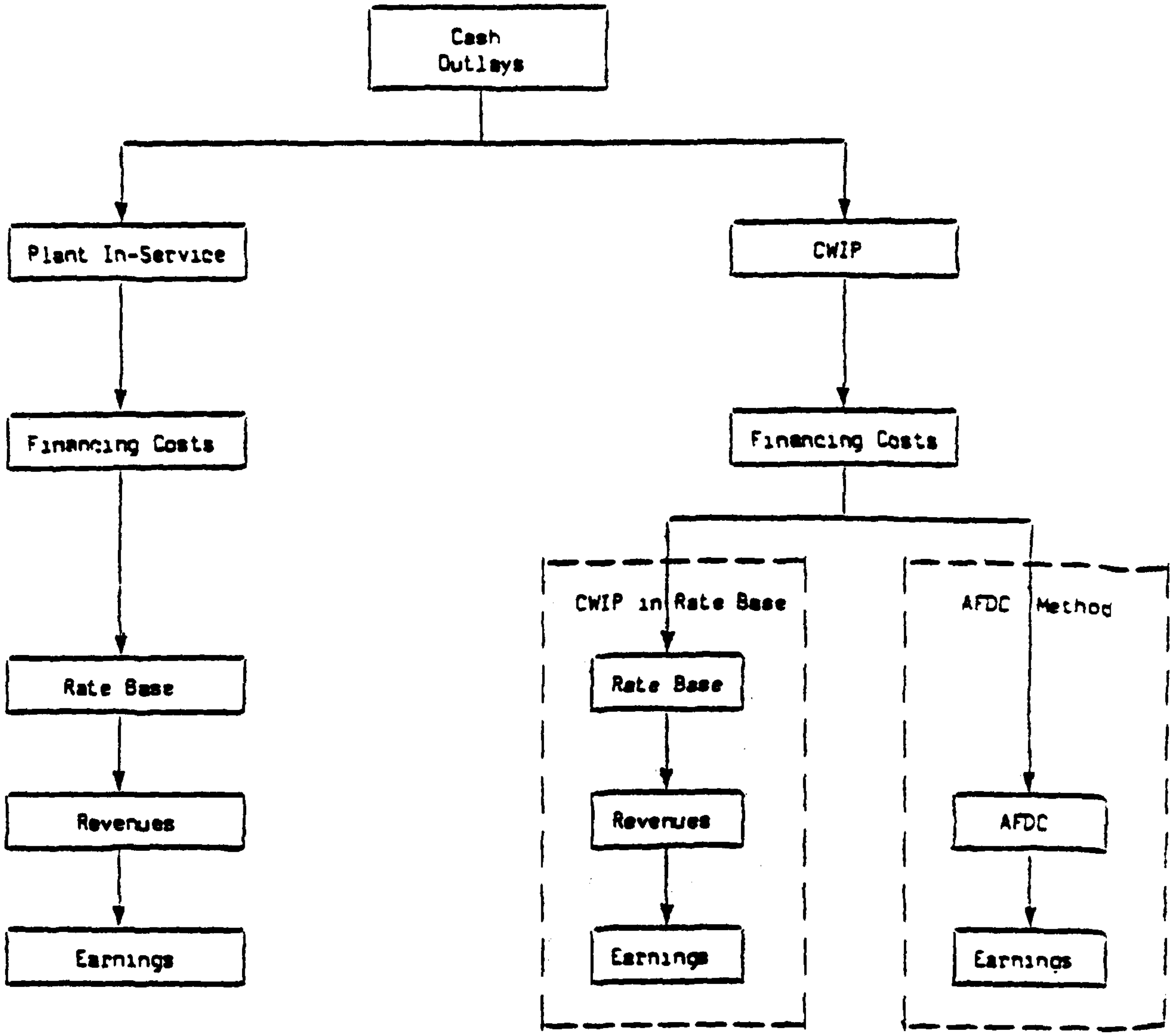
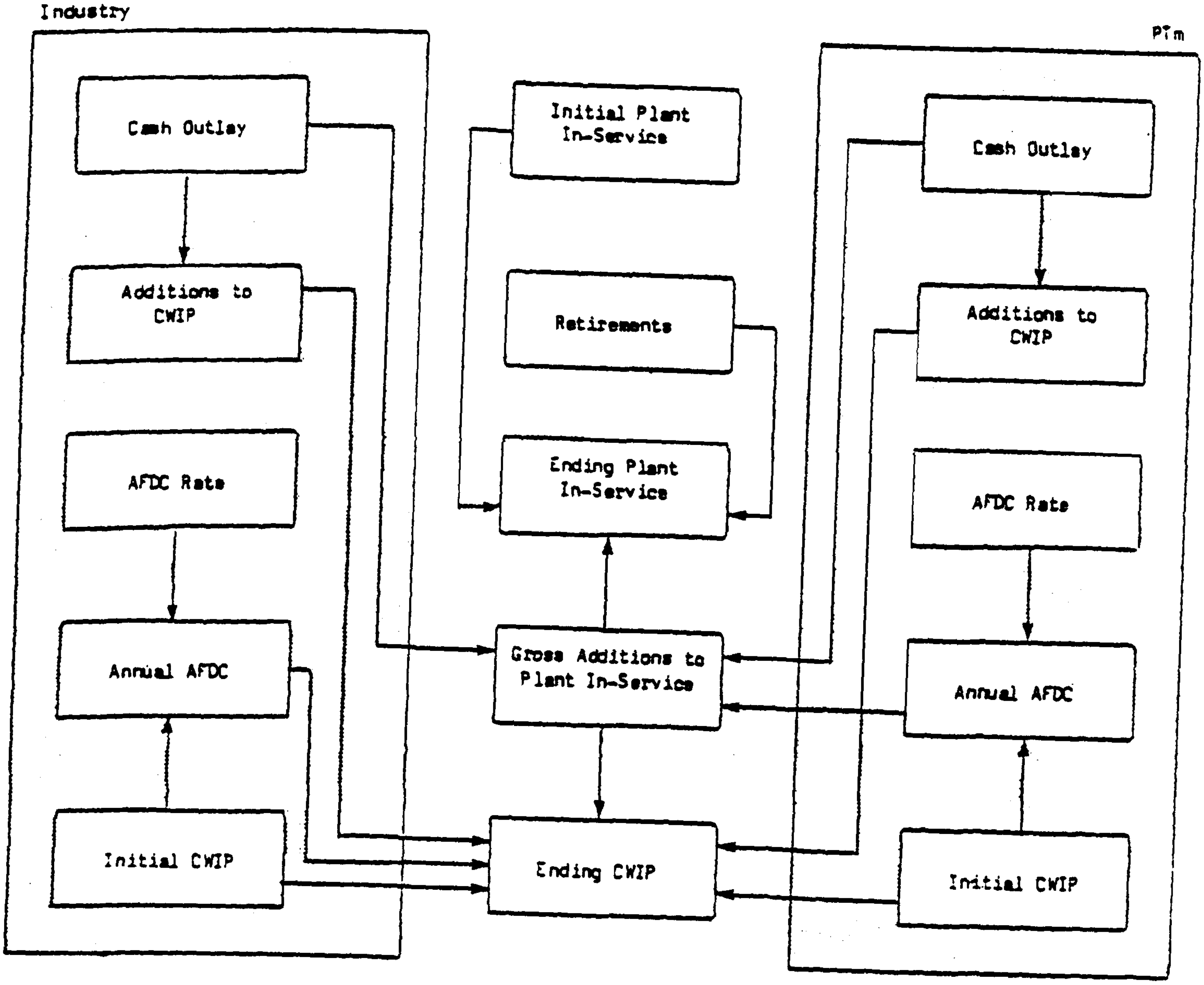


Figure C-2

DETERMINATION OF ANNUAL CHANGES TO PLANT IN-SERVICE AND CWIP ACCOUNTS: INDUSTRY VERSUS PTm TREATMENTS[1]



[1]The industry treatment described in this figure assumes the AFDC method of accounting for the financing costs associated with construction work in progress.

The result of the difference between PTm and the usual industry practice is that PTm generates lower AFDC amounts than the industry method because no compounding of the accrued AFDC occurs. Therefore, while the short-run plant in-service account will be greater under the PTm treatment, PTm's plant in-service account values can be lower in the long run to the extent that cumulative compounding of AFDC occurs. The total CWIP and plant in-service accounts will be lower in the PTm projections by the amount of compound AFDC. Coverage ratios excluding AFDC will show an improvement under the PTm treatment since total AFDC is lower than under the typical industry treatment.

The actual industry data used as inputs to PTm were adjusted to reflect PTm's method of computing and allocating AFDC. In total, $7 billion of approximately $48 billion (in 1979 dollars) in the 1979 privately owned utilities' CWIP account were transferred to plant in-service. This amount is the estimated portion of the CWIP account represented by AFDC.

Table C-1 provides an example of the effect on AFDC accrual, revenue requirements, and selected balance sheet items of various accounting procedures. While many simplistic assumptions are made regarding rates of return and the timing of accounting allocations, it does indicate the direction of the change in selected capital accounts under various accounting treatments. As indicated, short-run plant in-service and rate base accounts are higher using the PTm methodology because AFDC charges are allocated directly to those accounts. As a result short-run annual operating revenues are higher. If CWIP is allowed in the rate base, short-run revenue requirements are higher, but eventually both annual and cumulative operating revenues can be lower than under AFDC or PTm accounting conventions. Further, evidence suggests that the cost of capital for utilities that are allowed to include CWIP in the rate base is lower, reducing revenue requirements still more.

Table C-1

EXAMPLES OF VARIOUS TREATMENTS OF CAPITAL EXPENDITURES

(dollars)

	Year 1	2	3	4	5	6
Cash Outlays						
Plant 1	100.0	100.0	250.0	-	-	-
Plant 2	-	100.0	100.0	250.0	-	-
Typical Industry Treatment (AFDC Method)						
Flows						
Cash Outlay	100.0	200.0	350.0	250.0	-	-
AFDC[1]	5.0	20.0	47.5	32.5	-	-
Revenue Requirements[2]	-	-	-	50.3	100.5	100.5
Balance Sheet Items[3]						
CWIP Balances	105.0	325.0	722.5	502.5	-	-
Plant In-Service	-	-	-	502.5	1,005.0	1,005.0
Rate Base	-	-	-	502.5	1,005.0	1,005.0
CWIP in Rate Base						
Flows						
Cash Outlay	100.0	200.0	350.0	250.0	-	-
AFDC[1]	-	-	-	-	-	-
Revenue Requirements[2]	10.0	30.0	65.0	90.0	90.0	90.0
Balance Sheet Items[3]						
CWIP Balances	100.0	300.0	650.0	450.0	-	-
Plant In-Service	-	-	-	450.0	900.0	900.0
Rate Base	100.0	300.0	650.0	900.0	900.0	900.0
PTm Treatment						
Flows						
Cash Outlay	100.0	200.0	350.0	250.0	-	-
AFDC[1]	5.0	20.0	47.5	32.5	-	-
Revenue Requirements[2]	0.5	2.5	7.3	55.5	100.5	100.5
Balance Sheet Items[3]						
CWIP Balances	100.0	200.0	350.0	250.0	-	-
Plant In-Service	5.0	25.0	72.5	555.0	1,005.0	1,005.0
Rate Base	5.0	25.0	72.5	555.0	1,005.0	1,005.0

[1] AFDC is calculated on the average CWIP account balance using a 10 percent interest rate. No compounding of AFDC is assumed. *However, of the 44 state commissions responding to the National Association of Regulatory Utility Commissioners (NARUC) survey, only four explicitly disallow compounding of AFDC (NARUC, 1979 Annual Report on Utility and Carrier Regulation, October 1980).*

[2] Revenue requirements are calculated on the end-of-year rate base balance using a 10 percent interest rate.

[3] Balance sheet items are for the end of the year indicated.

APPENDIX D

COAL PRICES

Appendix D

COAL PRICES

The prices of coals of different types are determined by a variety of considerations, including the environmental regulations affecting electric utilities. Other factors influencing coal prices include the overall demand for energy, the prices of oil and natural gas, the costs of burning coal versus the alternatives, the availability of reserves of different types of coal in various regions, mining costs for each type in each region, and transportation costs. This appendix provides a brief overview of how these factors interact to determine coal prices.

UTILITY OPERATING AND CONSTRUCTION DECISIONS

The primary determinant of coal demand is the economics of coal versus alternative fuels for the generation of steam in domestic utility and industrial boilers. Of this demand, utility use is by far the larger. Coal is also used to make coke for metallurgical purposes and as a source of industrial process heat in kilns. Furthermore, coal is exported to Europe, Asia, and elsewhere for metallurgical, utility, and industrial uses. (See Table D-1 for data on the major markets for U.S. coal.) Given the central importance of domestic

Table D-1

1981 COAL USES

(millions of tons)

Utility	580
Industrial	71
Metallurgical	58
Export	111
Total	821

Total may not add because of rounding.

Source: U.S. Department of Energy, Energy Information Administration, Coal Distribution, January-December 1981, April 1982.

utility usage, and given that nonmetallurgical consumption is affected by similar considerations, this appendix focuses on how utility operating and construction decisions affect the price of coal.

Capacity Utilization Decisions

At any particular point in time, a utility has a fixed stock of generating equipment and, in meeting its demand for electricity, can only control the amount of electricity it generates in each of its units or purchases from others. This dispatching decision is generally made to minimize the variable costs of meeting any particular level of demand.

A utility's variable costs are determined by two primary factors. The first is the delivered price per million Btu of the available fuels that can be burned in each of the utility's boilers (or turbines) and that can meet environmental standards. The second is the thermal efficiency or heat rate of each unit. (A related consideration for many utilities is the efficiency of pumped storage for hydrogeneration.) The product of these factors is the fuel cost per kilowatt-hour (kWh) of generation from a particular unit. In addition to fuel costs, the use of a particular unit may involve other variable costs, such as incremental operation and maintenance labor and materials expenses, but these tend to be much smaller than fuel costs and are not discussed at any length in this appendix.

In dispatching particular units to minimize variable costs, a utility must meet a variety of physical constraints, including environmental requirements. They also include keeping boilers operating--if only at low levels and perhaps not producing power--to provide reliability protection for the utility system (or power pool) or for a particular geographical zone. Furthermore, dispatching has to take account of a variety of physical characteristics of a particular unit and all other units in a system, such as minimum power output levels, start-up and shut-down times, maximum rate of change of power output, and maintenance requirements. In sum, these constraints mean that dispatching--and hence the consumption of coal and other fuels--is not determined solely by the "merit order" of units (or increments of capacity for any given unit), i.e., their variable costs per kWh when operating at different "stops," or levels of output.

Environmental regulations affect dispatching primarily through their effects on the costs of the fuels, on the heat rates, and on the other variable costs of operating units so as to comply with those regulations. In some circumstances, problems with the quality of ambient air or with the availability of cooling water may preclude the operation of a unit altogether or may cause it to be operated below full output levels.

Fuels Conversion Decisions

In contrast to dispatching decisions, where equipment capabilities are fixed, fuels conversion decisions involve changes in a utility's existing equipment to reduce total costs over time, rather than the variable costs as of a particular (shorter) period of time. As discussed in Chapter III, given current regulatory practices in most jurisdictions, fuels conversion decisions are generally constrained by another utility objective, that of providing fair return to stockholders, and they may be constrained by the practical difficulty of raising any additional capital to finance the costs of conversion on reasonable terms.

Whether a utility can convert a unit to coal, which generally has much lower current or prospective cost per million Btu than oil or gas,[1] is constrained by a number of considerations. These include the capital availability problems mentioned above. They also include environmental regulations which make the burning of coal impossible for all practical purposes. Finally, they include physical limitations, such as the lack of space for coal storage or additional pollution control equipment, which make conversions economically--if not physically--impossible.

Of the feasible conversions, the economic attractiveness is determined by a panoply of considerations. These include the change in total fuel and other operation and maintenance expenses over time, including any fuel premiums or disposal costs related to environmental requirements, for the utility system as a whole. These cost savings depend in turn on the reliability and remaining life of the converted unit. The

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[1] At a delivered cost of $48 per ton, for example, a 12,000-Btu-per-pound coal costs $2.00 per million Btu. Residual oil at $24 per barrel is roughly twice as costly. Some natural gas is presently priced at or below $2.00 per million cubic feet, or $2.00 per million Btu, but the planned demise of price regulation will almost certainly lead to a major increase even in areas where gas currently sells at prices below those of residual oil.

economics of a conversion secondly involve the capital expenditures required for the conversion and the costs of financing those expenditures, including any pollution control equipment. Finally, the economic attractiveness of a conversion depends on the relative technical, price, and regulatory uncertainties involved in burning coal instead of the original fuel. It is these factors that combine to determine whether a utility's customers would, over time, gain from a conversion to coal.

As suggested above, current rate and environmental regulatory practices and requirements tend to inhibit conversions to coal. In the face of rate regulation that produces inadequate returns on investment, utilities tend to find the raising of additional financing to be difficult and unattractive. Environmental regulations tend to add to the capital costs of conversions and thus increase these financing difficulties, as well as decrease the economic gains from conversions.

Capacity Addition Decisions

Given the general utility objective of meeting demand with acceptable levels of reliability, growth in a utility's demand leads ultimately to the need for capacity expansion--although in a number of cases, various load management techniques are proving cost-effective and are reducing load growth below previously expected rates. In making capacity expansion decisions, utilities are typically guided by the customer and shareholder objectives mentioned in connection with conversions. These are the minimization of total customer costs over the long run (while still maintaining adequate reliability) and the provision of fair returns to investors.

There are several initial determinants of the feasibility and attractiveness of various capacity expansion alternatives. As discussed in Chapter III, these include capital availability, environmental regulations which may inhibit the siting of certain types and sizes of generating plants, and energy regulations which may altogether prohibit the consumption of oil or gas.

There are several major determinants of the costs to consumers associated with various choices of new plant design, fuel, and site. The first is delivered fuels prices, including any premiums associated with environmental regulations, at the potential new plant and at all other generating units in the utility's system. The second is nonfuel operation and maintenance costs, again at the new unit and other units. (The system costs are relevant because, as discussed in connection with dispatching, the value of any given new unit depends on the characteristics of the other units that it supplements or displaces.) The third element in consumer costs is the capital expenditures associated with each generation alternative, including pollution control expenditures. Fourth is the cost of capital required to finance these expenditures. Fifth is the reliability and longevity of the new equipment and its fuel supply. The final determinants of the expected costs and risks of each capacity expansion alternative are a variety of technical, price, and regulatory uncertainties.

The financial and shareholder considerations affecting new capacity decisions are in essence the same as those affecting conversions. Thus environmental regulations, by increasing capital expenditure requirements, generally tend in the current rate regulatory environment to make the implementation of least-consumer-cost capacity expansion decisions more difficult and more painful for shareholders. Moreover, to the extent that new coal units involve higher capital outlays than do new oil or gas units--and much higher outlays than the preservation of economically obsolete oil or gas units--applicable environmental regulations in the current rate regulatory environment tend particularly to inhibit the construction of new coal-fired capacity.

COAL PRICES IN THE ABSENCE OF ENVIRONMENTAL REGULATIONS

In the absence of environmental regulations, coal prices and production volumes by type and by region are determined by three major factors. The first is the value of each coal vis-a-vis alternative fuels at each powerplant. The second is transportation costs. The third is the costs of producing each type of coal in each region.

Determinants of Delivered Coal Prices

As discussed above, utility plants are constructed and dispatched so as to produce the lowest possible delivered electricity costs consistent with reliability objectives, shareholder interests, and other considerations. The amounts of plant capacity, the location of that capacity, and the fuels burned at each plant in turn depend on: the availability and delivered costs of each type of fuel (including different coal types); the associated nonfuel operation and maintenance expenses; the capital costs associated with burning each fuel; and the reliability of each type of equipment and fuel supply.

After adjusting for the differential capital and other costs associated with burning coal, the delivered price of coal must be--if any is to be consumed--at or below the price (in the long run) of the cheapest alternative fuel. Furthermore, coal prices may be expected to be significantly below the price of alternative fuels after adjusting for non-fuel-related expenses. In the many instances where there are multiple competing types and suppliers of coal to a particular generating plant, the delivered price of the coal may be as low as the total of transportation costs and mine-mouth production costs for the least-cost transport-mine combination.

Transportation Costs

Because transportation costs frequently are larger than production costs, coal-burning utility plants--particularly in the eastern United States--are sited wherever possible close to coal mines or on navigable waterways. Table D-2 shows approximate rail rates for selected long rail moves. For short hauls, conveyor systems or trucking may be an effective competitor to rail transport, helping to curb costs. With respect to water transport, costs per ton-mile tend inherently to be lower and competition among barge and ship operators precludes large markups on costs.

Table D-2

SELECTED RAIL RATES

(1980 dollars)

Origin	Destination	Miles	Rate per Ton[1]
Colstrip, MT	Superior, WI	814	$10.56[a]
Cordero, WY	San Antonio, TX	1,651	22.25
Wattis, UT	Los Angeles, CA	900	20.21
Belle Ayn, WY	Amarillo, TX	940	13.47[a]
Fair View, WV	Bow, NH	870	15.89

[1] All rates presume carrier-supplied cars.
[a] Unit-train rates.

Source: Published tariffs; TBS analysis.

Where either a utility plant or a coal mine can be served only by one railroad, that railroad has a monopoly, but the rates it charges are subject to review in certain circumstances by the Interstate Commerce Commission, so that abuses of monopoly power are constrained. However, within the bounds set by regulation, practices vary substantially among railroads. Railroads differ, for example, in their willingness to offer rates that reflect the economies of scale in unit-train operations and the volumes of coal typically consumed by a single coal-fired generating unit, e.g., often 2 million or more tons per year. Railroads also differ in their willingness to set rates that make it possible to transport coal over two (or more) rail systems. As railroad practices evolve in response to the recent relaxation of regulation (the Staggers Act of 1980), long-term contracts that reflect the economics of volume movements may lead to a situation where rates reflect the costs of efficient operations, including a fair return on capital.

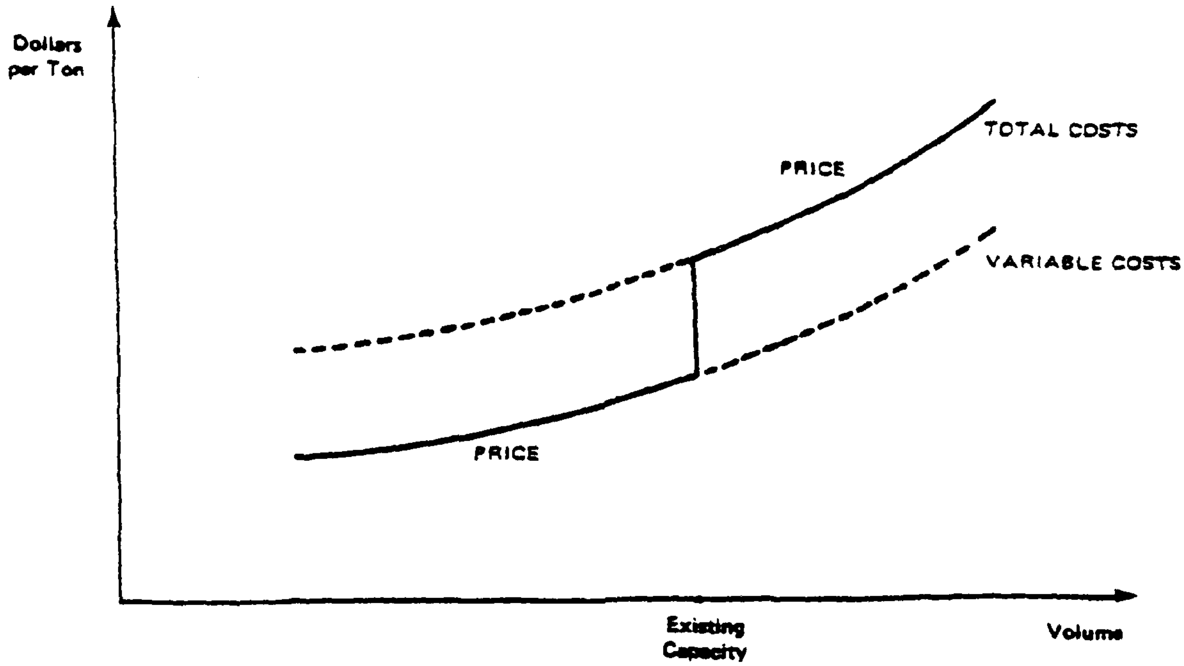
Determinants of Mine-Mouth Coal Prices and Volumes

Assuming that transportation costs from alternative sources of coal to a particular consumer of coal are known, the highest possible mine-mouth price for a particular coal is the difference between its delivered value (adjusted for capital and operating cost differentials between competing fuels, including other coals) and transportation costs. Whether this price is attractive and whether coal is produced from a particular reserve turn on the costs of mining that coal and on alternate uses of existing or potential new capacity for mining that coal.

In the short run, where there exists excess capacity for producing coal, mine-mouth costs may be viewed as the variable costs of production, i.e., the incremental labor, materials, and other costs incurred by incremental production. As suggested by Figure D-1, presuming that production from a single mine or from a region comes first from the most efficient sections of a single mine or from the lowest cost mines in a region, variable costs increase with increasing production volume. Because such costs do not include a return on capital, mine owners obviously try to avoid having to price at levels approaching variable costs. Unfortunately for producers, however, the coal industry has often tended to overbuild relative to the demand that has materialized. Thus, for most recent years and for most producers, prices have not reflected a reasonable return on capital. In the worst case for producers, as shown in Figure D-1, prices would be equal to variable costs until demand exceeds existing capacity.

Figure D-1

MINE-MOUTH COSTS AND PRICES



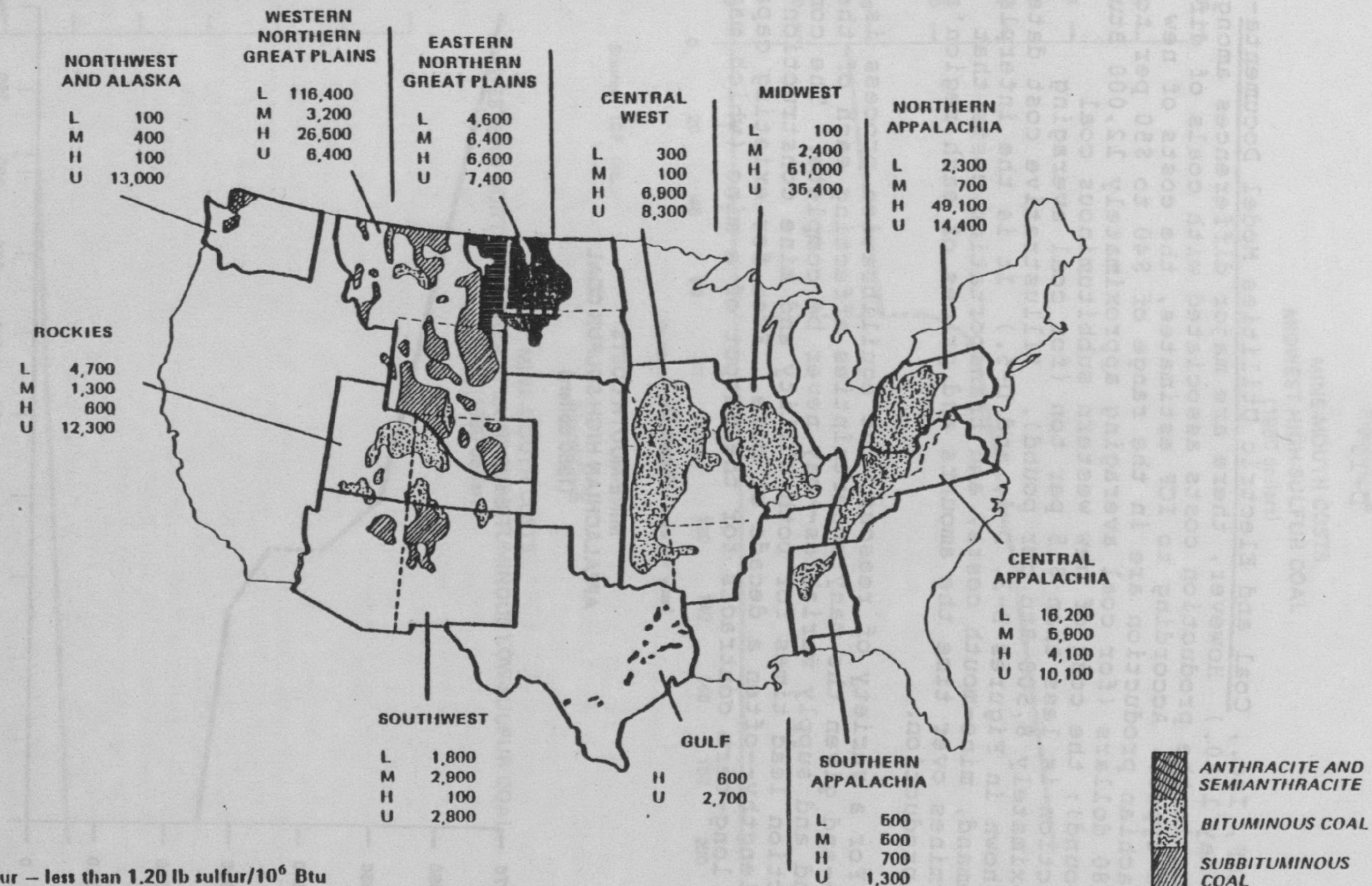
In the long run, capacity and demand may come to be more in balance and, if so, mine-mouth costs can be viewed as including both variable and fixed costs. This equilibration of supply and demand will involve shifts in three factors: first, in the amounts of mining capacity for various types of coal in various regions; second, in the amount, specific design, and location of coal-fired utility generating plants; and third (perhaps to a lesser extent), in the costs of transportation between various origin-destination pairs. Ultimately, to elicit investment by producers in new mine capacity, prices must rise to levels expected to cover the full costs of production from this incremental capacity. As is also suggested by Figure D-1, presuming that reserves are developed and mined in order of their costs, prices for coals of a particular type from a particular region will rise until demand for that coal, which is itself related to the price of that coal, is equated to supply.

The level of both variable and fixed costs and the production volumes of various coals are dependent on the amounts, thickness, depth, and many other characteristics of the reserves of various coals. There are enormous reserves of coal in the continental United States. (See Figure D-2; for consistency with EPA's coal price assumptions, the data are taken

Figure D--2

COAL RESERVES BY SULFUR CONTENT

(millions of tons)



L = Low Sulfur -- less than 1.20 lb sulfur/10^6 Btu
M = Medium Sulfur -- 1.20-1.67 lb sulfur/10^6 Btu
H = High Sulfur -- more than 1.67 lb sulfur/10^6 Btu
U = Unclassified

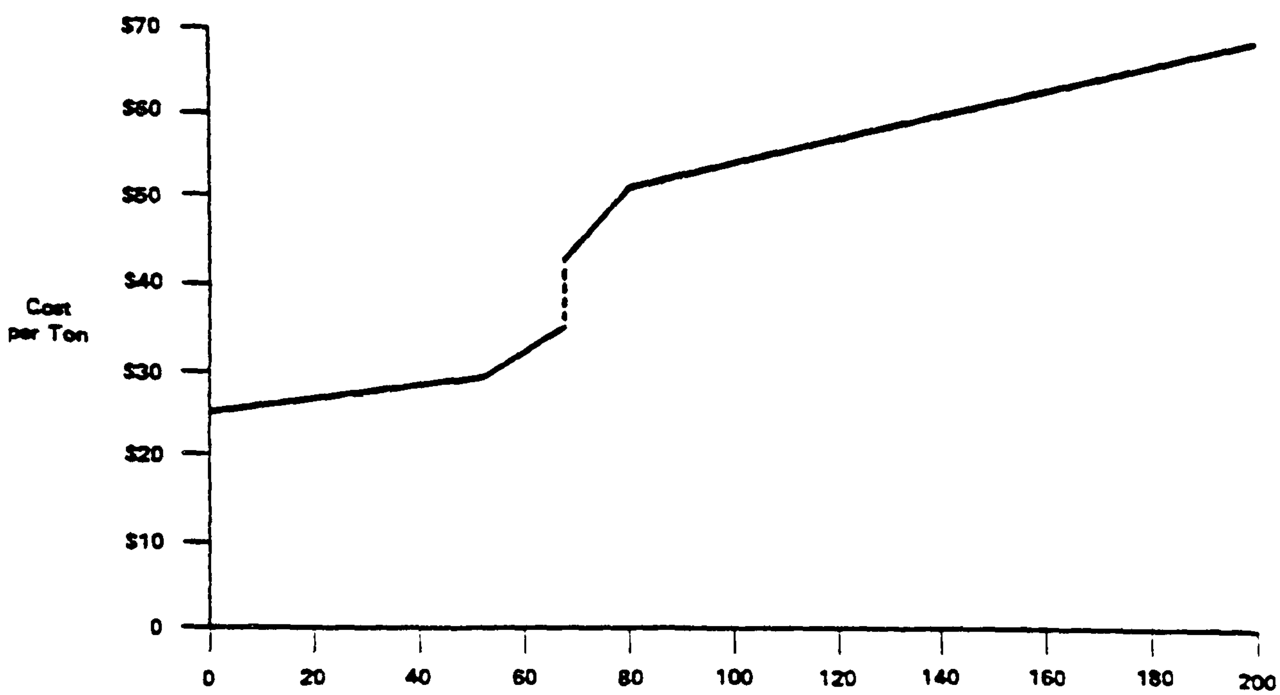
Source: ICF, Inc.; memorandum dated November 10, 1981.

from ICF, Inc., <u>Coal and Electric Utilities Model Documentation</u>, May 1980.) However, there are major differences among regions in the production costs associated with coals of different types. According to ICF estimates, the costs of new Appalachian production are in the range of $40 to $50 per ton in 1980 dollars (for coal averaging approximately 12,000 Btu per pound); the cost of new western subbituminous coal production is less than $15 per ton (for coal averaging approximately 8,500 Btu per pound). (Illustrative cost data are shown in Figures D-3, D-4, and D-5.) It is the interplay of demand, mine-mouth costs, and transportation costs that determines over time the amounts and prices of each region's coal production.

For a variety of reasons, the equilibration process is slow--and given the many uncertainties affecting each of the demand and supply variables--may never be complete. The construction lead times for both utility and mine construction are lengthy--often a decade or more. Even for existing capacity, long-term contracts for the output of a mine (which may

Figure D—3

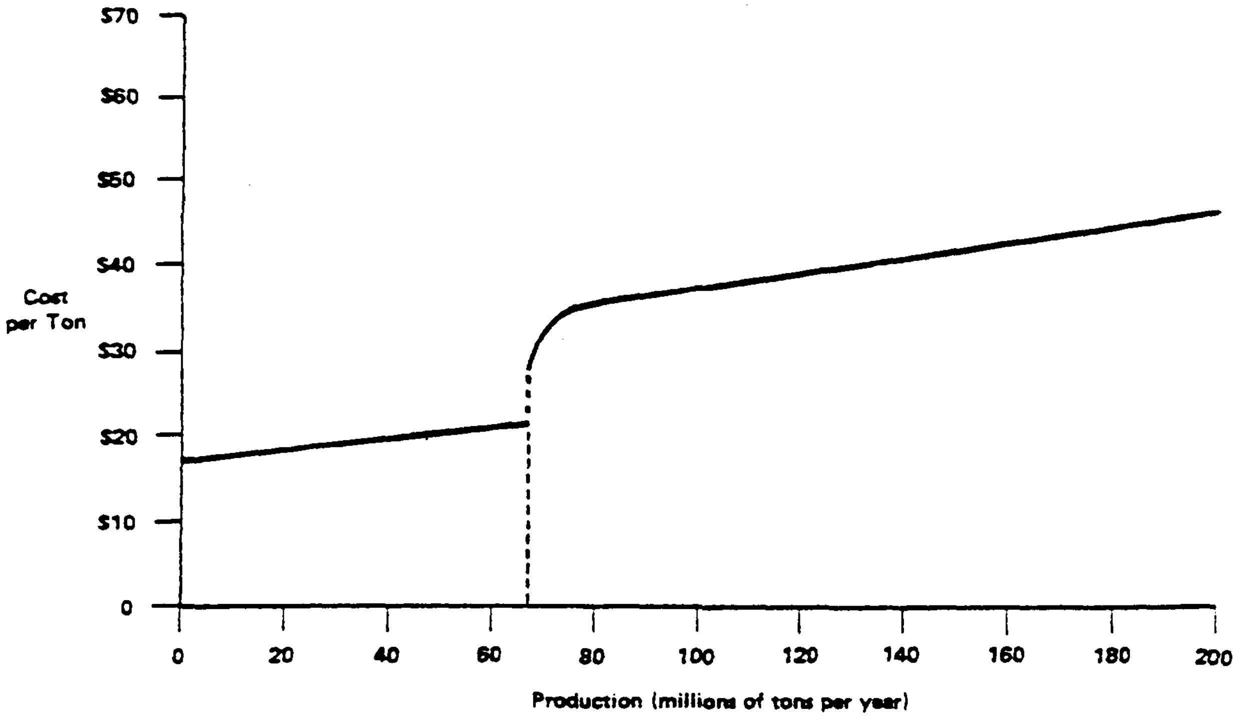
MINE-MOUTH COSTS
APPALACHIAN HIGH-SULFUR COAL
(1980 dollars)



Source: ICF, Inc.

Figure D—4

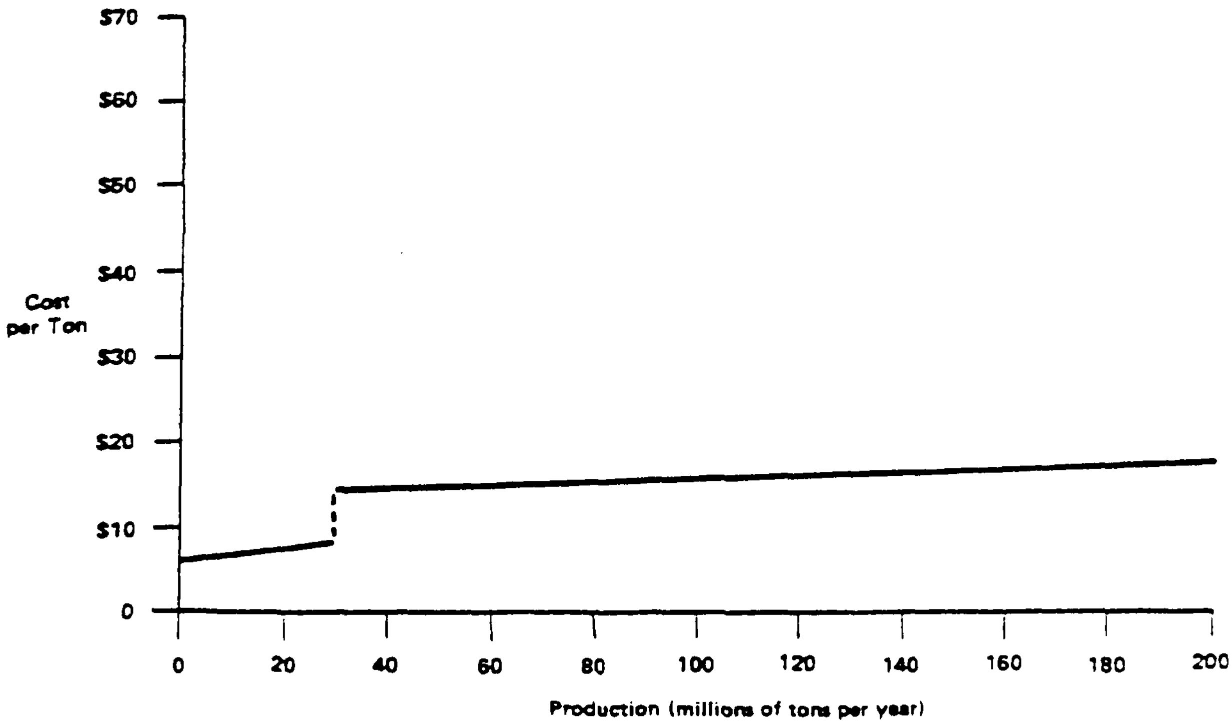
MINE-MOUTH COSTS
MIDWEST HIGH-SULFUR COAL
(1980 dollars)



Source: ICF, Inc.

Figure D—5

MINE-MOUTH COSTS
WESTERN NORTHERN GREAT PLAINS SUBBITUMINOUS LOW-SULFUR COAL
(1980 dollars)



Source: ICF, Inc.

run for 20 years or more) and utility ownership of coal mines may inhibit adjustments. On the other hand, long-term contracts are often key to a coal producer's being willing to invest in new capacity.

THE EFFECTS OF ENVIRONMENTAL REGULATIONS ON COAL PRICES AND AMOUNTS

Environmental regulations governing the combustion of coal affect coal prices both in the short and long run. (Regulations affecting the mining of coal are ignored in this appendix, although they are also of major importance.) The long-run effects arise because certain coals become technically or economically impossible to burn or because the burning of such coals entails higher capital and operating costs. The short-run effects arise to the extent that the character of the regulations is not correctly anticipated by the coal industry and that the implementation of the regulation gives rise to nonequilibrium excess- and deficit-capacity situations.

Although it is impossible to ascribe the full differential wholly to environmental regulations or to partition the causes into short- and long-run causes, in those regions with coals of varying sulfur content, current prices usually (but not always) reflect substantial sulfur premiums. Recent prices for selected coals of different sulfur content are shown in Table D-3.

Short-Run Implications

To the extent that more stringent environmental regulations on, say, sulfur dioxide (SO_2) emissions, are unanticipated, a chain of events occurs that tends to create substantial sulfur premiums. Relative to what otherwise would have been the case, the imposition of new or additional SO_2 regulations causes the consumption of high-sulfur coal to decrease. To the extent that the decrease is unexpected, high-sulfur coals will be in oversupply and high-sulfur coal prices will tend to decline toward variable production costs. Conversely, the desired consumption of low-sulfur coals tends to increase, production tends to rise toward the limits of available capacity, and low-sulfur coal prices tend to rise until mine-mouth prices plus transportation costs reflect the delivered costs of alternative fuels or of coals from more remote regions that have excess capacity. In both cases, long-term contractual provisions may preclude some immediate shifts in response to the unanticipated regulatory changes.

Table D-3

MID-1982 SPOT COAL PRICES

Region	Sulfur Content	Ash Content	Price per million Btu
Southern West Virginia, eastern Kentucky, northern Tennessee, parts of Virginia	1.6	13.0	$2.13
Western Kentucky	3.6	14.2	1.82
	2.5	10.0	2.32
Illinois	3.5	13.0	1.71
	2.5	8.5	1.71
Kansas, Missouri, parts of Oklahoma	4.5	11.0	2.11
	0.7	9.0	3.00

Source: Coal Week, July 19, 1982; TBS analysis.

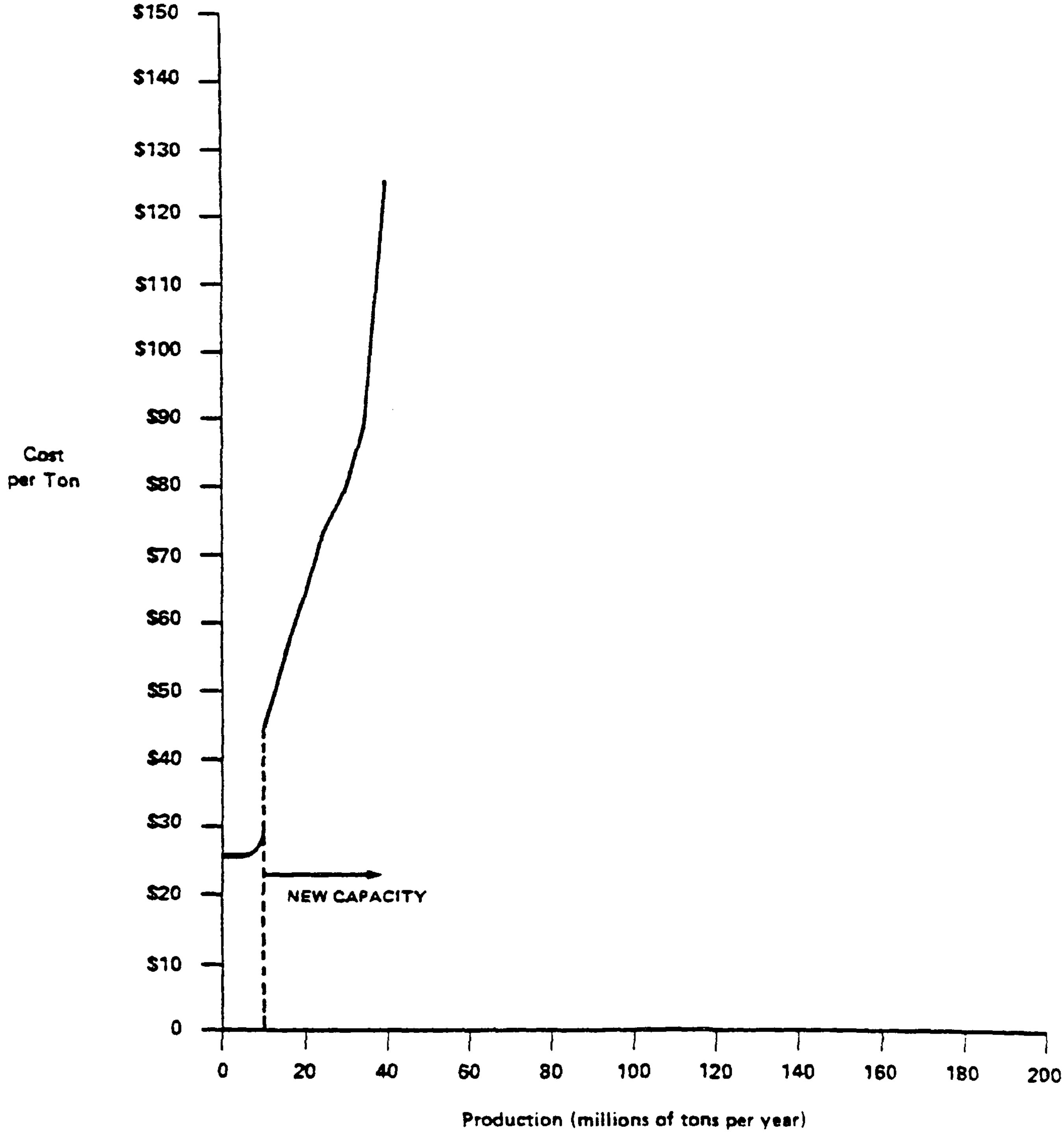
Long-Run Implications

In the longer run, environmental regulations still tend to create premiums for low-sulfur (and low-ash) coals. Most of the reserves of low-sulfur coals in the East and Midwest are mineable only at production costs that are significantly above those of high-sulfur coals. As an example, compare the low-sulfur coal cost curve for the Appalachian region, Figure D-6, with the cost curve for Appalachian high-sulfur coal, Figure D-3. However, the premiums in equilibrium should be smaller in the long run for several reasons. First, excess high-sulfur capacity should diminish, in part because of mine closings and in part because utilities will add flue gas desulfurization, coal washing, or other equipment enabling them to burn high-sulfur coals and still comply with regulations. Second, coal producers and transporters will invest in developing new mines in and transportation facilities for low-sulfur coal reserves. While such investment will be made only if low-sulfur coal prices allow attractive returns on investment, the amount of low-sulfur coal reserves in the United States and the competitiveness of the coal industry will preclude monopolistic returns. Nonetheless, long-run equilibrium delivered coal prices with environmental regulations will, in most regions, contain a significant sulfur premium.

While there remain some uncertainties and limitations in the technology, the existence of desulfurization equipment and

Figure D—6

MINE-MOUTH COSTS
APPALACHIAN LOW-SULFUR COAL
(1980 dollars)



techniques places some upper bounds on sulfur premiums. Scrubbers with 90 percent removal efficiencies add roughly 13 mills per kWh in annual capital and operation and maintenance costs to electricity costs in 1980 dollars. Seventy percent scrubbing adds 10 mills. The differential of 3 mills per kWh is equivalent to $7.60 per ton of coal.[2] Thus, a 3.0 percent sulfur coal scrubbed with 90 percent efficiency and a 0.67 percent sulfur coal scrubbed with 70 percent efficiency should, in theory, differ in price by no more than $7.60 per ton for reasons of sulfur content. If there is a $7.60 per ton differential, the cost of producing electricity should be the same for both scrubber technologies.

Implications of Alternative Types of Environmental Regulations

The character of environmental regulations affects coal prices. In particular, regulations expressed in terms of technology requirements have different effects on prices than regulations expressed in terms of performance standards--even if the technology requirements are set so as to attain equivalent environmental results. A first reason is that, to the extent that technology standards are not identical to the least-cost methodology for meeting a particular air quality standard, the price of electricity will be higher than would otherwise be the case, electricity use would be reduced, and accordingly, coal use and coal prices would be lower.

The second major result of technology requirements vis-a-vis performance standards is to change the distribution of coal consumption by type. Notably, the minimum scrubbing requirement for NSPS II units tends to decrease the consumption and prices of low-sulfur coal relative to what would be burned if performance standards were the sole requirement, as is the case for existing facilities. This does not mean that

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[2]TBS performed the conversion from mills per kWh to 1980 dollars per ton as follows:

dollars per ton = mills per kWh x kWh per ton x 1/1,000
kWh per ton = Btu per pound x pounds per ton x kWh per Btu

For this calculation, TBS assumed 12,000 Btu per pound and 9,600 Btu per kWh.

technology standards do not create sulfur premiums, merely that such premiums are lower than would be the case with performance standards leading to the same emission levels. Both tend to lead to a preference for low-sulfur coals, to greater production and higher prices of such coals, and to increased levels of coal cleaning relative to what would occur in the absence of environmental regulations. Conversely, environmental regulations tend to harm the economic viability of high-sulfur mines and the economic well-being of the miners, companies, and regions associated with high-sulfur coal.

APPENDIX E

TERMS, ACRONYMS, AND CONVERSION FACTORS

Appendix E

TERMS, ACRONYMS, AND CONVERSION FACTORS

This appendix provides definitions of the major terms and acronyms used throughout this report. In addition, some useful conversion factors are included.

DEFINITIONS

These definitions are derived primarily from Edison Electric Institute's Glossary of Electric Utility Terms.

Accelerated Depreciation. See Depreciation, Liberalized.

Accumulated Deferred Income Taxes. A group of balance sheet accounts, representing the net balances arising from charges to income that are equivalent to the reductions in income taxes of the current and prior periods. Such reductions result from the use, for tax purposes, of deductions which, for book purposes, will not be fully reflected in the determination of book net income until subsequent periods. Most commonly, these taxes arise from normalizing the tax reductions that result from the use of accelerated amortization or liberalized depreciation for tax purposes instead of straight-line or other nonliberalized depreciation methods used for book purposes.

Accumulated Deferred Investment Tax Credit. Net unamortized balance of investment tax credits which are being spread over the average useful life of the related property or some other shorter period. This balance sheet account is built up by charges against income in the years in which such credits are realized (the years in which the qualified property additions go into service) and is reduced subsequently through credits to income.

Acquisition Adjustments. See Plant Acquisition Adjustments.

Additions at Cost. Gross additions to, and betterments, renewals, and replacements of, utility plant, including those carried in Construction Work in Progress (CWIP)--at actual cost--whether for cash or other consideration and including utility plant acquired. Plant additions described in this report include the interest portion of CWIP, but not the cash portion. Please refer to Appendix C for additional explanation of the accounting procedures.

Adverse Hydro (adverse water conditions). Water conditions limiting the production of hydroelectric power either from low or restricted water supply or reduced gross head.

Allowance for Funds Used During Construction. Listed in the income account as a subdivison of Other Income, and representing amounts concurrently credited for interest that are charged to the cost of constructing new plant, and that are based generally on the amount expended to date on particular projects. The rate used may represent the net cost for the period of funds borrowed for construction purposes with a reasonable rate upon other funds when so used, or a predetermined rate representing the average cost of capital may be used.

Amortization. The gradual extinguishment (or accumulated provision or reserve) of an amount in an account by prorating such amount over a predetermined period, such as the life of the assest or liability to which it applies, or the period during which it is anticipated the benefit will be realized.

Annual Peak Load. See Demand, Annual Maximum.

Annual System Maximum Demand. See Demand, Annual System Maximum.

Assets (and other debits). Items of value owned by or owned to a business. Represents either a property right or value acquired, or an expenditure made which has created a property right or is properly applicable to the future. Utility assets include: utility plant, other property and investments, current and accrued assets, and deferred debits.

Availability, Operating. The percent of time the unit was available for service, whether operated or not. It is equal to available hours divided by the total hours in the period under consideration, expressed as a percentage.

Average Annual Customer Charge. Annual revenue (excluding forfeited discounts and penalties) divided by the average number of customers served for the 12-month period. A customer with two or more meters at the same location because of special services, such as water heating, etc., is counted as one customer. Customer charges described in this report typically refer to revenues per kilowatt-hour. See "Average Revenue per Kilowatt-Hour Sold."

Average Annual kWh Use per Customer. Annual kilowatt-hour sales divided by the average number of customers for the same 12-month period. A customer with two or more meters at the same location because of special services, such as water heating, etc., is counted as one customer.

Average Demand. See Demand, Average.

Average Number of Customers. The arithmetic averages of month-end customers in each of 12 consecutive months. For those billed other than every month, the number of such customers is adjusted to a 12-month basis (e.g., for bimonthly billing, the number of customers billed, or counted, in each month is multiplied by two and the resultant averaged for the 12-month period).

Average Number of Shares Outstanding. The weighted average number of shares of common stock outstanding in the hands of the public during the period for which earnings per share are to be computed. Use of the weighted average is necessary so that the effect of increases or decreases in outstanding shares on earnings per share data is related to the portion of the period during which the proceeds were applicable. The number of shares outstanding at any time should, of course, be adjusted to give retroactive effect to any subsequent stock dividends or stock splits.

Average Revenue per Kilowatt-Hour Sold (average price of electricity). Revenue from the sale of electricity (excluding forfeited discounts and penalties) divided by the corresponding number of kilowatt-hours sold. Referred to in this report as customer charges.

Base Load. The minimum load over a given period of time.

Base Load Station. A generating station which is normally operated to take all or part of the base load of a system and which, consequently, operates essentially at a constant output.

Bond Ratings. Rating systems which provide the investor with a simple series of graduation by which the relative investment qualities of bonds are indicated. Moody's Investor Service and Standard & Poor's Corporation are the principal bond rating agencies.

Bonds (mortgage). Certificates of indebtedness representing long-term borrowing of capital funds, the terms of which contain an indenture pledging the property as security for the loan and providing for the appointment of a trustee to represent the bondholders. If the lien of the mortgage is limited to specific property owned at the time the mortgage was created and to replacements for the property, the mortgage is described as "closed." If the lien extends to "after acquired" property which may be used as the basis for issuance of additional bonds under the terms and provisions of the indenture, the mortgage is referred to as an "open-end" mortgage.

<u>Book Amounts</u>. The amounts recorded on a company's accounting records at any given time, usually at the most recent closing date or at year-end. These amounts may reflect historical cost, original cost, or current value.

<u>Book Cost</u>. The amount at which assets are recorded in the accounts without deduction of related accumulated provisions for depreciation, amortization, or other purposes.

<u>Book Value per Share of Common Stock</u>. Common Stock Equity (see definition) divided by the number of common shares outstanding at the date of the computation.

<u>Btu (British thermal unit)</u>. The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

- <u>Content of Fuel, Average</u>. The heat value per unit quantity of fuel expressed in Btu as determined from tests of fuel samples. Examples: Btu per pound of coal, per gallon of oil, etc.

- <u>Equivalent of Fuels Burned</u>. The Btu equivalent of fuels burned is the aggregate heat energy of all fuels burned. It is derived by calculating total Btu content of each kind of fuel burned and totaling to establish the Btu content of all fuels burned.

<u>Btu per Kilowatt-Hour</u>. See Heat Rate.

<u>Capability</u>. The maximum load which a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time, without exceeding approved limits of temperature and stress.

- <u>Gross System</u>. The net generating station capability of a system at a stated period of time (usually at the time of the system's maximum load), plus capability available at such time from other sources through firm power contracts.

- <u>Net Generating Station</u>. The capability of a generating station as demonstrated by test or as determined by actual operating experience less power generated and used for auxiliaries and other station uses. Capability may vary with the character of the load, time of year (due to circulating water temperatures in thermal stations or availability of water in hydro stations), and other characteristic causes. Capability is sometimes referred to as effective rating.

- Net System. The net generating station capability of a system at a stated period of time (usually at the time of the system's maximum load), plus capability available at such time from other sources through firm power contracts less firm power obligations at such time to other companies or systems.

- Peaking. Generating capability normally designed for use during the maximum load period of a designated time interval.

Capability Margin (reserve margin). The difference between net system capability and system maximum load requirements (peak load). It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads. On a regional or national basis, it is the difference between aggregate net system capability of the various systems in the region or nation and the sum of system maximum (peak) loads without allowance for time diversity between the loads of the several systems. However, within a region, account is taken of diversity between peak loads of systems that are operated as a closely coordinated group.

Capacity. The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer.

- Dependable. The load-carrying ability for the time interval and period specified when related to the characteristics of the load to be supplied. Dependable capacity of a station is determined by such factors as capability, operating power factor, and portion of the load which the station is to supply.

- Hydraulic. The rating of a hydroelectric generating unit or the sum of such ratings for all units in a station or stations.

- Peaking. Generating units or stations which are available to assist in meeting that portion of peak load which is above base load.
- Purchase. The amount of power available for purchase from a source outside the system to supply energy or capacity.
- Reserve Margin. See Capability Margin.

Capacity Factor. The ratio of the average load on a machine or equipment for the period of time considered to the capacity rating of the machine or equipment.

Capital Expenditures (capital outlay). Cost of construction of new utility plant (additions, betterments, and replacements) and expenditures for the purchase or acquisition of existing utility plant facilities. See Appendix C for additional details.

Capital Stock. Represents ownership in a corporation. If there is no preferred or other special class of stock, common stock and capital stock are synonymous. See also Common Capital Stock or Common Stock.

Capitalization. The total of: Long-Term Debt, Preferred Stock, and Common Stock Equity. For balance sheet presentation, several modifications are sometimes made: current maturities of Long-Term Debt are not included in the Capitalization section, but Short-Term Debt (with an original maturity of less than one year), which will be refinanced by Long-Term Debt, is sometimes included.

Capitalization Ratios. The percentages of: Long-Term Debt, Preferred Stock, and Common Stock Equity (or their components) to Total Capitalization.

Coincident Demand. See Demand, Coincident.

Commercial and Industrial. A customer, sales, and revenues classification covering energy supplied for commercial and industrial purposes, except that supplied under special contracts or agreements or service classifications applicable only to municipalities or divisions or agencies of federal or state governments or to railroads and railways. Usually subdivided into Commerical and Industrial or into Small Light and Power and Large Light and Power. Most companies classify such customers as Commerical or Industrial using the Standard Industrial Classification or predominant kWh use as yardsticks;

others still classify as Industrial all customers whose demands or annual use exceeds some specified limit. These limits are generally based on a utility's rate schedules.

Common Capital Stock or Common Stock. Shares of stock issued and stated at par value, stated value, or the cash value of the consideration received for such no par stock; none of which is limited or preferred to distribution of earnings or assets.

Common Stock Dividends. Dividends declared on Common Stock and charged to unappropriated retained earnings during a stated period, whether or not they were paid during such period. Such dividends only include those payable in cash unless otherwise specified (i.e., payable in stock).

Common Stock Equity. The funds invested in the business by the residual owners whose claims to income and assets are subordinate to all other claims. Includes Common Capital Stock (less reacquired), Other Paid-In Capital, and Retained Earnings. Installments, Received on Capital Stock, Discount on Capital Stock, and Capital Stock Expense are usually included in either Common or Preferred Capital Stock according to the nature of the transactions. Premimum on Preferred Stock and certain reserves are sometimes included in Common Stock Equity.

Construction Expenditures (gross). Expenditures (may or may not include interest or other overheads charged to construction) for construction including additions to and betterments, renewals, and replacements of utility plant during a specific period, but not money spent for maintenance or for the acquisition of existing utility systems or segments. See Appendix C for additional details.

Construction Work in Progress. A subaccount in the utility plant section of the balance sheet representing the sum of the balances of work orders for utility plant in the process of construction but not yet placed in-service.

Cost (net) of Capital. The return asked, or being asked, by investors for the use of their money committed to investment in utility companies, expressed as percentages of the capital funds (debt, preferred stock, common equity).

- For Common Stock. A mathematical computation, whose formula varies, of expected future earnings to the net proceeds received from the sale of common stock after deducting underwriters' commission, and other costs of issuance, including pressure and allowance for underpricing in a rights offering--or ratio of expected future earnings to current market price. Since many factors enter into estimating future earnings (e.g., territory served, regulatory climate, interest costs, growth prospects, management, etc.) the calculation cannot be measured precisely and can only be estimated on the basis of informed judgment.

- For Long-Term Debt. The contractual interest rate expressed as a percentage of the net proceeds, less estimated financing expenses, currently being received from the sale of new issues of bonds of companies.

- For Preferred Stock. The contractual dividend rate expressed as a percentage of the net proceeds, less estimated financing expenses, currently being received from the sale of new issues of preferred stock.

- For Short-Term Debt. The contractual interest rate being asked by financial institutions for short-term loans and by sellers of commercial paper on loans maturing in less than one year. The effective rate on short-term bank loans may be greater because of the requirement to maintain compensating balances.

Customer (electric). An individual, firm, organization, or other electric utility which purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location is counted as a separate customer unless the consumptions are combined before the bill is calculated.

Debentures. Certificates of indebtedness issued under an indenture agreement (administered by a trustee) representing long-term borrowings of capital funds, and secured only by the general credit of the issuing corporation.

Deferred or Future Income Taxes. Amounts representing income tax reductions resulting from the use of accelerated amortization or liberalized depreciation in income tax returns.

<u>Demand</u>. The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment. It is expressed in kilowatts, kilovoltamperes, or other suitable units at a given instant or averaged over any designated period of time. The primary source of Demand is the power-consuming equipment of the customers. See Load.

- <u>Annual Maximum</u>. The greatest of all demands of the load under consideration which occurred during a prescribed demand interval in a calendar year.

- <u>Annual System Maximum</u>. The greatest demand on an electric system during a prescribed demand interval in a calendar year.

- <u>Average</u>. The demand on, or the power output of, an electric system or any of its parts over any interval of time, which is determined by dividing the total number of kilowatt-hours by the number of units of time in the interval.

- <u>Billing</u>. The demand upon which billing to a customer is based, as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.

- <u>Coincident</u>. The sum of two or more demands which occur in the same demand interval.

- <u>Instantaneous Peak</u>. The maximum demand at the instant of greatest load, usually determined from the readings of indicating or graphic meters.

- <u>Integrated</u>. The demand usually determined by an integrating demand meter or by the integration of a load curve. It is the summation of the continuously varying instantaneous demands during a specified demand interval.

- <u>Maximum</u>. The greatest of all demands of the load under consideration which has occurred during a specified period of time.

- <u>Noncoincident</u>. The sum of two or more individual demands which do not occur in the same demand interval. Meaningful only when considering demands within a limited period of time, such as a day, a week, a month, a heating or a cooling season; usually for not more than one year.

Demand Charge. The specified charge to be billed on the basis of the billing demand, under an applicable rate schedule or contract.

Demand Factor. The ratio of the maximum demand over a specified time period to the total connected load on any defined system.

Demand Interval. The period of time during which the electric energy flow is averaged in determining demand, such as 60-minute, 30-minute, 15-minute, or instantaneous.

Dependable Capacity. See Capacity, Dependable.

Depletion (allowance). A charge against income for the pro rata cost of extracted depletable natural resources such as coal, gas, oil, etc.

Depreciation (provision for). Charges made against income to provide for distributing the cost of depreciable plant less estimated net salvage over the estimated useful life of the asset (using mortality turnover or other appropriate methods) in such a way as to allocate it as equitably as possible to the period during which services are obtained from the use of facilities. Among the factors to consider are: wear and tear, decay, inadequacy, obsolescence, changes in demand, and requirements of public authorities.

- Straight-Line Method. Under this method of computing provisions for depreciation, the cost of the asset less estimated salvage is allocated in equal amounts over the asset's estimated useful life.

- Liberalized. This refers to certain approved methods of computing depreciation allowance for federal or state income tax purposes, applicable to plant additions with a useful life of three years or more. These methods permit relatively larger depreciation charges during the earlier years of the life of the property and relatively smaller charges during the later years, in contrast with the straight-line method, under which the annual charges are the same for each year.

--Declining Balance Method. One of the liberalized methods of computing depreciation deductions. Under this method, the depreciation rate is stated as a fixed percentage (up to twice the applicable straight-line rate) per year, and the annual charge is derived by applying the rate to the net plant balance, which is determined by subtracting the accumulated depreciation deductions of previous periods from the cost of the property. When the property of any vintage year is almost fully depreciated, it is necessary to add to the reserve the small remaining amount required to bring the reserve up to 100 percent of the retirement value (cost less salvage); otherwise depreciation charges would continue on in decreasingly smaller amounts to infinity.

--Sum of the Years' Digits ("SYD") Method. Another of the liberalized methods of computing depreciation deductions. Under this method the annual deduction is derived by multiplying the cost of the property, less estimated net salvage, by the estimated number of years of service life remaining, and dividing the resultant product by the sum of all the digits corresponding to the total years of estimated service life. For a property with an assumed 25-year life the sum of the digits would be 25 + 24 + 23 + 22 + . . . + 5 + 4 + 3 + 2 + 1, or 325. A simple way to compute this figure would be to multiply the number of years by the number of years plus 1 and divide by 2, i.e., (25 x 26) ÷ 2 = 325. The first year's full depreciation deduction would be 25/325ths; the second year's would be 24/325ths, etc., of the cost of the property.

Direct Current (DC). Electricity that flows continuously in one direction, as contrasted with alternating current.

Discount on Capital Stock. The excess of par or stated value over the price paid to the company by the shareholders for all original issue shares of its capital stock. In balance sheet presentation, discount on capital stock is usually treated as a deduction from proprietary capital.

Dispatching. The operating control of an integrated electric system involving operations such as:

(1) The assignment of load to specific generating stations and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rises or falls.

(2) The control of operation and maintenance of high-voltage lines, substations, and equipment, including administration of safety procedures.

(3) The operation of principal tie lines and switching.

(4) The scheduling of energy transactions with connecting electric utilities.

<u>Distribution</u>. The act or process of distributing electric energy from convenient points on the transmission or bulk power system to the consumers. Also a functional classification relating to that portion of utility plant used for the purpose of delivering electric energy from convenient points on the transmission system to the consumers, or to expenses relating to the operation and maintenance of distribution plant.

<u>Diversity</u>. That characteristic of variety of electric loads whereby individual maximum demands usually occur at different times. Diversity among customer's loads results in diversity among the loads of distribution transformers, feeders, and substations, as well as between entire systems.

<u>Diversity Factor</u>. The ratio of the sum of the noncoincident maximum demands of two or more loads to their coincident maximum demand for the same period.

<u>Earnings Per Share</u>. The earnings attributable to common stock for a stated period divided by the weighted average number of shares outstanding during the period. The term should not be used without qualifying language if potentially dilutive convertible securities, options, warrants, or other agreements that provide for contingent issuances of common stock are outstanding.

<u>Earnings Price Ratios</u>. Earnings per share on Common Stock divided by its market price. The market price used may be a spot price or an average of the closing or high and low prices for a period; the earnings are for the corresponding period and may be either actual or estimated annual rate.

<u>Earnings Retained in the Business</u>. The remainder of net income for the period (usually for the reporting year) after deducting preferred and common dividends payable in cash.

Electric Utility Industry, or Electric Utilities. All enterprises engaged in the production or distribution of electricity for use by the public, including investor-owned electric utility companies; cooperatively-owned electric utilities; and government-owned electric utilities. The term refers to the annual costs attached to the ownership of property such as depreciation, taxes, insurance, cost of money, and in some instances, rents, general and administrative expenses, and necessary regular maintenance.

Flow-Through Method. An accounting method under which decreases or increases in state or federal income taxes resulting from the use of liberalized depreciation and the Investment Tax Credit for income tax purposes are carried down to net income in the year in which they are realized.

Fuel Clause. A clause in a rate schedule that provides for adjustment of the amount of the bill as the cost of fuel varies from a specified base amount per unit.

Fuel Costs (most commonly used by electric utility companies)

- Cents Per Million Btu Consumed. Since coal is purchased on the basis of its heat content, its cost is measured by computing the "cents per million Btu" of the fuel consumed. It is the total cost of fuel consumed divided by its total Btu content, and multiplied by one million.

- Coal. Average cost per short ton (dollars per ton)--includes bituminous and anthracite coal and relatively small amounts of coke, lignite, and wood.

- Gas. Average cost per cents per thousand cubic feet--includes natural, manufactured, mixed, and waste gas. Frequently expressed as cost per therm (100,000 Btu).

- Nuclear. Nuclear fuel costs can be given on a fuel cycle basis. A fuel cycle consists of all the steps associated with procurement, use, and disposal of nuclear fuel. Accounting for the cost of each step in the fuel cycle including interest charges, nuclear fuel costs can be given in cents per million Btu or mills per kilowatt-hour for the cycle lifetime of the fuel, which is normally five to six years.

- Oil. Average cost per barrel--42 gallons (dollars per barrel)--includes fuel oil, crude and diesel oil, and small amounts of tar and gasoline.

Generating Station (generating plant or powerplant). A station at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, or nuclear energy into electric energy.

Generating Unit. An electric generator together with its prime mover.

Generation, Electric. This term refers to the act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kilowatt-hours.

- Gross. The total amount of electric energy produced by the generating units in a generating station or stations.

- Net. Gross generation less kilowatt-hours consumed out of gross generation for station use.

Heat Rate. A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Income Taxes. A subdivision of Operating Expenses or of Other Income and Deductions or Extraordinary Items. Income Taxes (federal and state) applicable to nonutility operations are allocated to Other Income and Deductions, and to Extraordinary Items, if appropriate. Used in the broad sense Income Taxes include, in addition to federal and state income taxes: Provisions for Deferred Income Taxes, Income Taxes Deferred in Prior Years--Credit and Investment Tax Credit Adjustments--Net.

Interest Charges. A section or group of accounts in the income statement which represents principally the amounts accrued as expenses for the cost of borrowed funds. Includes: Interest on Long-Term Debt, Amortization of Debt Discount and

Expense, Amortization of Premium on Debt-Credit, Interest on Debt to Associated Companies, and Other Interest Expense.

Interest on Long-Term Debt. Interest on outstanding debt which is or was due one year or more from the date of issuance.

Internal Combustion Engine. A prime mover in which energy released from the rapid burning of a fuel-air mixture is converted into mechanical energy. Diesel, gasoline, and gas engines are the principal types in this category.

Invested Capital. The sum of Capitalization, Long-Term Debt Due Within One Year, and Short-Term Debt.

Investment Tax Credit. The credit against federal income taxes provided by the Revenue Act for qualified depreciable assets after December 31, 1961, and before April 18, 1969, except for a suspension period (October 10, 1966, to March 9, 1967).

Investor-Owned Electric Utilities. Those electric utilities organized as tax-paying businesses usually financed by the sale of securities in the free market, and whose properties are managed by representatives regularly elected by their shareholders. Investor-owned electric utilities, which may be owned by an individual proprietor or a small group of people, are usually corporations owned by the general public.

Kilowatt (kW). 1,000 watts (defined herein).

Kilowatt-hour (kWh). The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Liabilities and Other Credits. Amounts recorded in books of account which represent obligations to creditors, items deferred or in suspense, and the equity of shareowners. Includes Capitalization (Long-Term Debt and Proprietary Capital), Current and Accrued Liabilities, Deferred Credits, Operating Reserves, Contributions in Aid of Construction, and Accumulated Deferred Taxes on Income.

Load. The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customers. See Demand.

- Average. See Demand, Average.

- Base. See Base Load.

- Connected. Connected load is the sum of the capacities or ratings of the electric power-consuming apparatus connected to a supplying system, or any part of the system under consideration.

- Peak. See Demand, Maximum, and Demand, Instantaneous Peak.

Load Curve. A curve on a chart showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.

Load Diversity. The difference between the sum of the maxima of two or more individual loads and the coincident or combined maximum load, usually measured in kilowatts.

Load Factor. The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

Long-Term Debt. Includes outstanding mortgage bonds, debentures, advances from associated companies, and notes which are due one year or more from date of issuance. The portion of such securities (inclusive of sinking fund requirements) that is due within one year from the date of the balance sheet is usually included in Current and Accrued Liabilities, but Long-Term Debt to be refinanced within one year should continue to be reported under Long-Term Debt.

Long-Term Financing. Refers to the issuance and sale of debt securities with a maturity of more than one year, and preferred or common stock for the purpose of raising new capital or refunding outstanding securities.

Loss (losses). The general term applied to energy (kilowatt-hours) and power (kilowatt) lost in the operation of an electric system. Losses occur principally as energy transformations from kilowatt-hours to waste heat in electrical conductors and apparatus.

- Average. The total difference in energy input and output or power input and output (due to losses) averaged over a time interval and expressed either in physical quantities or as a percentage of total input.

- Energy. The kilowatt-hours lost in the operation of an electric system.

- Line. Kilowatt-hours and kilowatts lost in transmission and distribution lines under specified conditions.

- Peak Percent. The difference between the power input and output, as a result of losses due to the transfer of power between two or more points on a system at the time of maximum load, divided by the power input.

- System. The difference between the system net energy or power input and output, resulting from characteristic losses and unaccounted for between the sources of supply and the metering points of delivery on a system.

Maintenance Expenses. A subdivision of Operating Expenses--includes labor, materials, and other direct and indirect expenses incurred for preserving the operating efficiency or physical condition of utility plant used for power production, transmission and distribution of energy, and administrative and general operations.

Margin of Reserve Capacity. See Capability Margin.

Maximum Demand. See Demand, Maximum.

Maximum Load. See Demand, Maximum.

Megawatt (MW). 1,000 kilowatts.

Municipally Owned Electric System. An electric utility system owned or operated by a municipality engaged in serving residential, commercial, or industrial customers, usually--but not always--within the boundaries of the municipality.

Name Plate Rating. The full-load continuous rating of a generator, prime mover, or other electrical equipment under specified conditions as designated by the manufacturer. It is usually indicated on a name plate attached mechanically to the individual machine or device. The name plate rating of a steam-electric turbine-generator set is the guaranteed continuous output in kilowatts or kVA and power factor at generator terminals when the turbine is clean and operating under specified throttle steam pressure and temperature, specified reheat temperature, specified exhaust pressure, and with full extraction from all extraction openings.

NARUC. The National Association of Regulatory Utility Commissioners--an advisory council composed of federal and state regulatory commissioners having jurisdiction over transportation agencies and public utilities.

Net (Available) for Common Stock. Net Income less dividends on Preferred Stocks applicable to the period.

Net Income. Income before Interest Charges less Interest Charges plus or minus Extraordinary Items.

Net Other Income and Deductions. Other Income less Other Income Deductions plus or minus Taxes Applicable to Other Income and Deductions.

Normalizing (or deferred) Method.

- For Deferred or Future Income Taxes. An accounting method under which decreases or increases in income taxes, usually resulting from the use of accelerated amortization or liberalized depreciation deductions in income tax returns (federal and state), compared with straight-line depreciation used for book purposes, are offset in the income account by corresponding credits or charges to balance sheet accounts maintained for accumulating the net balances of deferred and future income taxes. Charges (provisions) equal to the related tax deferrals are made against income when the use of accelerated amortization or liberalized depreciation produces lower income taxes than would be the case if straight-line depreciation had been used in the company's tax return. Conversely, credits (feedbacks) are made to income when taxes are increased because for tax purposes the related facilities were fully amortized or the applicable accelerated method resulted in a rate lower than straight-line depreciation. Charges for taxes deferred until future years reduce current year book income; feedback credits for taxes deferred in prior years increase current year book income.

- For Investment Tax Credit. The accounting method used by companies not flowing through to income the entire investment tax credit in the year the credit is realized. The credit to the income account is offset by providing an amount equivalent to the reduction in income taxes and allocating to income an appropriate portion of it over the life of the asset giving rise to the tax credit or over some shorter period.

Nuclear Energy. Energy produced in the form of heat during the fission process in a nuclear reactor. When released in sufficient and controlled quantity, this heat energy may be used to produce steam to drive a turbine-generator and thus be converted to electrical energy.

Nuclear (atomic) Fuel. Material containing fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.

Nuclear Power. Power released in exothermic (a reaction which gives off heat) nuclear reactions which can be converted to electric power by means of heat transformation equipment and a turbine-generator unit.

Oil Burned for Fuel. Oil burned for fuel includes fuel oil, crude oil, diesel oil, and small amounts of tar and gasoline, with fuel oil predominating. See Fuel for Electric Generation.

Operating Expenses. A group of expenses applicable to utility operations composed of: Operation Expense, Maintenance Expense, Provisions for Depreciation and Amortization, Taxes Other Than Income Taxes, Income Taxes, Provision for Deferred Income Taxes, Income Taxes Deferred in Prior Years--Credit, and Investment Tax Credit Adjustments--Net.

Operating Income. Operating Revenues less Operating Expenses.

Operating Ratio. The ratio, generally expressed as a percentage, of Operating Expenses to Operating Revenues. This may be for total operations, or for a single departmental operation, such as electric or gas. (In special variations, the numerator may be defined as exclusive of depreciation or taxes, or both.)

Operating Revenues. The amounts billed by the utility for utility services rendered and for other incidental services.

Power Pool. A power pool is two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance program.

Preferred Stock or Preferred Capital Stock. Capital Stock to which preferences or special rights attach particularly as to dividends or proceeds in liquidation.

Preferred Stock Dividends or Preferred Dividend Charges. The amount of preferred dividends (declared or accrued) that are deductible from Net Income in arriving at the earnings for Common Stock for any given period of time.

Price Earnings (P/E) Ratio. Market price divided by the annual earnings per share of common stock. The market price used may be a spot price, or an average of closing, or the high and low prices for a period; the earnings are for the corresponding period and may be either the actual or an estimated annual rate.

Provisions for Deferred (future) Income Taxes. Charges against income (with corresponding credits to a special liability account) representing the tax deferrals resulting from the use of accelerated amortization or liberalized depreciation in federal or state income tax returns, when the deductions for such rapid depreciation and amortization (applied to any vintage year's property) exceed the allowance that would have been taken if straight-line depreciation had been used for tax return as well as for book purposes. Many companies net in this account the feedback of a prior year's provisions for deferred taxes. See Normalizing (or deferred) Method.

Public Utility District. A political subdivision (quasi-public corporation of a state), with territorial boundaries embracing an area wider than a single municipality (incorporated as well as unincorporated) and frequently covering more than one county for the purpose of generating, transmitting, and distributing electric energy.

Pumped Storage. An arrangement whereby additional electric power may be generated during peak load periods by hydraulic means using water pumped into a storage reservoir during off-peak periods.

Rate Base. The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return. Generally this represents the amount of property used and useful in public service and may be based on the following values or combinations of values: fair value, prudent investment, reproduction cost, or original cost; and it may provide for the inclusion of cash working capital, materials and supplies, and deductions for: Accumulated Provision for Depreciation, Contributions in Aid of Construction, Customer Advances for Construction, and Accumulated Deferred Income Taxes and Accumulated Deferred Investment Tax Credits.

Rate of Return. The ratio of allowed Operating Income to a specified rate base, expressed as a percentage.

System Output. The net generation by the system's own plants plus purchased energy, plus or minus net interchange energy.

Total Fuel Expense (after residual credit). Total cost (including freight and handling) of coal, oil, gas, nuclear, or other fuel used in the production of electric energy, less fuel portion of steam transfer credit, and residual credits, such as net credits from the disposal of ashes, cinders, and nuclear by-products.

Transmission. The act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems. Also a functional classification relating to that portion of utility plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of transmission plant.

Turbine-Generator. A rotary-type unit consisting of a turbine and an electric generator.

Turbine (steam or gas). An enclosed rotary type of prime mover in which heat energy in steam or gas is converted into mechanical energy by the force of a high velocity flow of steam or gases directed against successive rows of radial blades fastened to a central shaft.

Utility Plant. Includes plant: in-service, purchased or sold, in process of reclassification, leased to others, held for future use, completed construction not classified, construction work in progress, plant acquisition adjustments, other electric plant adjustments, and other utility plant. The Uniform System of Accounts prescribes for the deduction of accumulated provision for depreciation and amortization.

Utility Plant In-Service. That portion of a utility's plant which is devoted to the operations of the company. Excludes plant: purchased or sold, in process of reclassification, leased to others, held for future use, under construction, and acquisition adjustments and adjustment accounts, and without deduction of accumulated provision for depreciation and amortization. See Appendix C for further details.

Utilization Factor. The ratio of the maximum demand of a system or part of a system to the rated capacity of the system or part of the system under consideration.

Watt. The electrical unit of power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under the pressure of one volt at unity power factor. It is analogous to horsepower or foot-pounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

Winter Peak. The greatest load on an electric system during any prescribed demand interval in the winter or heating season, usually between December 1 of a calendar year and March 31 of the next calendar year.

Working Capital. The amount of cash or other liquid assets that a company must have on hand to meet the current costs of operations until such a time as it is reimbursed by its customers. Sometimes it is used in the narrow sense to mean the difference between Current and Accrued Assets and Current and Accrued Liabilities.

Yield. Percentage return based on the market price of a security. For common and preferred stock, the current annual dividend rate is divided by market price. In the case of bonds, yield is computed on the basis of the bonds being held to maturity. Yield to maturity is the current interest rate adjusted to amortize the related debt discount or premium over the remaining life of the bond. Such yields are published in bond yield tables.

ACRONYMS

AQCRs	air quality control regions
AFDC	allowances for funds used during construction
BACT	best available control technology
BAT	best available technology economically achievable
BCT	best conventional technology
BEJ	best engineering judgment
BPT	best practicable control technology
CEUM	Coal and Electric Utility Model
CTG	control techniques guidance
CWIP	construction work in progress
FERC	Federal Energy Regulatory Commission
FGD	fuel gas desulfurization
FUA	Powerplant and Industrial Fuel Use Act
GEP	good engineering practice
GURF	Generating Unit Reference File
LAER	lowest achievable emission rate
MBRs	market price to book value ratios
NAAQS	National Ambient Air Quality Standards
NCAQ	National Commission on Air Quality
NERC	National Electric Reliability Council
NO_x	nitrogen oxides
NPDES	national pollution discharge elimination system
NRC	Nuclear Regulatory Commission
NRDC	Natural Resources Defense Council
NSPS	new source performance standards
PCBs	polychlorinated biphenyls
POTWs	publicly owned treatment works
PSD	prevention of significant deterioration
PSES	pretreatment standards for existing sources
PSNS	pretreatment standards for new sources
PUCs	public utility commissions
RACT	reasonably available control technology
RCRA	Resource Conservation and Recovery Act
SIPs	state implementation plans
SO_2	sulfur dioxide
TSP	total suspended particulates
TSS	total suspended solids
UIC	underground injection control

CONVERSION FACTORS

The following are some useful conversion factors.

Conversion Factors--General

1 long ton	contains	1.120 short tons
1 short ton	contains	2,000 pounds
1 barrel	contains	42 gallons
1 barrel (crude oil)	weighs	0.136 metric tons (0.150 short tons)
1 therm (natural gas)	contains	100 cubic feet (or 100,000 Btu)
1 Btu	equals	0.000293 kilowatt-hours
1 Quad	equals	1 Quadrillion (10^{15}) Btu
1 kWh Produced	requires	10,500 Btu
1 kWh Consumed	equals	3,413 Btu

Aggregated Heat Content

Petroleum

Crude Oil	5.820 million Btu/barrel (172×10^6 barrels/Quad)
Refined products	
Imports, average	6.000 million Btu/barrel
Gasoline	5.248 million Btu/barrel
Distillate fuel oil	5.825 million Btu/barrel
Residual fuel oil	6.287 million Btu/barrel

Natural Gas

Natural gas liquids	4.011 million Btu/barrel
Natural gas	
Wet	1,097 Btu/cubic foot (1 trillion (10^9) cubic feet/Quad)
Dry	1,032 Btu/cubic foot

Uranium

Uranium in a Light Water Reactor	175,000 Btu/pound of ore

Coal

Coal, Average	22.5 million Btu/short ton (44.4×10^6 short tons/Quad)
Lignite	12.0-15.0 million Btu/short ton
Subbituminous	18.0-22.0 million Btu/short ton
Bituminous	24.0-30.0 million Btu/short ton
Anthracite	27.0-30.0 million Btu/short ton

Electricity Conversion Aggregate Heat Rates

Bituminous coal	9,850-10,500 Btu/kilowatt-hour
Subbituminous and lignite	10,100-10,700 Btu/kilowatt-hour
Gas	10,010-11,400 Btu/kilowatt-hour
Oil	9,650-12,000 Btu/kilowatt-hour
Nuclear steam-electric	11,000 Btu/kilowatt-hour
Hydroelectric	10,389 Btu/kilowatt-hour
10 MW boiler	100,200 Btu/hour
Purchased electricity	3,413 Btu/kilowatt-hour

Abbreviations

MB/D - thousands of barrels per day
MT/Y - thousands of tons per year
BCF - billions of cubic feet
Quad - quadrillion Btu
kWh - kilowatt-hour
MW - megawatt
GW - gigawatt (MMW)

1,000 MWe Coal Powerplant: Annual Emissions (approximate)

A 1,000 MWe powerplant uses 2.5 million tons of eastern coal/year (approx).

	Eastern Coal	Western Coal
SO_2 (no controls)	111,000 tons/yr	34,000 tons/yr
SO_2 (with wet limestone scrubbing)	15,000	4,800
NO_x (no controls)	20,300	26,400
Released particulates (no controls)	45,200	31,000
Released particulates (with ESP)	5,226	5,155

Sulfur Content and SO_2 Emissions

$$\text{pounds } SO_2/\text{MMBTU} = \frac{2\,(\text{percent sulfur of coal})}{\left(\dfrac{\text{Heat content in Btu/lb}}{10{,}000}\right)}$$

Pounds sulfur/ton = 38 (percent sulfur of coal by weight)