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CURRENT AND FUTURE USE OF COAL IN THE NORTHEAST

Bruce S. Edelston and Edward S. Rubin

May 1976

POLICY ANALYSIS DIVISION
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS
BROOKHAVEN NATIONAL LABORATORY
UPTON, NEW YORK 11973

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FOREWORD

This report is one of a number of issue papers prepared as part of the Brookhaven National Laboratory Northeast Energy Perspectives Study. The analyses in these papers were performed specifically to assist us in our first integrated study of the energy future of the northeastern United States.

Topics covered by the issue papers include the potential supply of energy to the Northeast from coal, oil, natural gas, liquefied natural gas (LNG), nuclear power, municipal waste, solar energy, and wind power, and the demand for energy in the Northeast from the industrial, transportation, and residential and commercial sectors. In each case a range of estimates of energy supply or demand was constructed to reflect not only a variety of possible policy and technological developments, but also the basic uncertainties of all such future projections. The integrative analysis which relates the supply and demand picture is presented in "A Perspective on the Energy Future of the Northeast United States."

The issue papers prepared for the Northeast Energy Perspectives Study and the summary report will be available from:

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The issue papers and summary report are listed below.

H. Broheim, "Future Oil Supply to the Northeast United States," BNL 50557 (June 1976).

R. J. Goettle, IV, "Alternative Patterns of Industrial Energy Consumption in the Northeast," BNL 50555 (March 1976).

R. N. Langlois, "Future Natural Gas Supply to the Northeast," BNL 50558 (April 1976).

J. Lee, "Future Residential and Commercial Energy Demand in the Northeast," BNL 50552 (March 1976).

P. M. Meier and T. H. McCoy, "Solid Waste as an Energy Source for the Northeast," BNL 50559 (June 1976).

P. M. Meier, T. H. McCoy, and S. Rahman, "Issues in the Future Supply of Electricity to the Northeast," BNL 50553 (June 1976).

B. S. Edelston and E. S. Rubin, "Current and Future Use of Coal in the Northeast," BNL 50560 (May 1976), Environmental Studies Institute, Carnegie-Mellon University, Pittsburgh, Penn.

V. L. Sailor and F. H. Shore, "The Future of Nuclear Power in the Northeast," BNL 50551 (March 1976).

G. R. Bray, S. K. Julin and J. A. Simmons, "Supply of Liquefied Natural Gas to the Northeast," BNL 50556 (April 1976), Science Applications, Inc., 1651 Old Meadow Road, McLean, Va.

System Design Concepts, Inc., "Transportation Energy Consumption and Conservation Policy Options in the Northeast," BNL 50554 (April 1976), System Design Concepts, Inc., 9 Rector Street, New York, N. Y. 10006.

J. Brainard et al., Editors, "A Perspective on the Energy Future of the Northeast United States," BNL 50550 (June 1976).

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ABSTRACT

This report discusses some of the problems of and potential for coal utilization in the Northeast region (defined as New England, New York, Pennsylvania, New Jersey, Delaware, Maryland, and the District of Columbia). Coal utilization in the Northeast now occurs mainly in Pennsylvania, where coal is used extensively for steel manufacturing and electricity generation. Elsewhere in the region, coal use is limited for the most part to electric power generation, and increased future reliance on coal is likely to be associated principally with this use. At present, oil supplies most of the energy used to generate electricity in the Northeast.

The first section reviews recent trends in national and regional coal utilization and presents an overview of potential options for and constraints on future coal use. These include mining and utilization technology, transportation system capacity, and environmental regulatory policy. Section II focuses on the outlook for future coal supplies in the region for the reference years of 1985 and 2000 adopted throughout the BNL Northeast Energy Perspectives Study. Current national projections are used to establish a range of possible production levels for each of the 23 U.S. Bureau of Mines coal production districts in the United States. Scenarios of low, medium, and high supply levels to the Northeast are then derived on the assumption that the Northeast will receive approximately the same share of each district's production in the future as it does presently. The resulting supply estimates are shown in the tabulation on the following page. Smaller supplies of anthracite coal could also become available regionally from eastern Pennsylvania and the Narragansett Basin of Massachusetts and Rhode Island. The regional availability of low-sulfur coal, however, will depend on interregional economic factors as well as on technical constraints and public policy. The transportation system of the Northeast could also constrain coal utilization, as discussed in Section III.

Section IV considers the potential demand for coal by electric utilities in the region. In the short term, increased demand would occur prinicipally from conversion of existing gas and oil-fired facilities to coal. For 1985, three coal demand scenarios are developed. These include coal use at "easily" converted plants not requiring sulfur emission controls; at "feasible" plants

Summary of Regional Supply and Demand Scenarios for 1985 and 2000

(Energy in 10^{15} Btu)

Case	1972	1985 Low	1985 Medium	1985 High	2000 Low	2000 Medium	2000 High
Domestically available coal supply	2.6	2.6	3.1	6.6	3.3	5.0	10.0
Electric utility coal demand	1.3	1.2	2.0	2.4	2.0	3.9	9.0
"Effective" supply of synthetic oil and gas	0.0	0.0	0.3	0.9	0.9	2.7	5.4

requiring installation of flue-gas desulfurization systems; and at other plants which might utilize coal if current emission regulations were relaxed. For each case, recent plant-specific studies and operating characteristics were used to estimate total regional conversion costs, SO_2 emissions, additional coal requirements, and resultant oil savings. A first-order benefit/cost analysis, taking into account the estimated cost of environmental damage due to SO_2 emissions, was also performed. Preliminary results suggest that a limited program of conversion to coal may indeed be cost-beneficial to the region, although the need for refinements in the methodological approach is also clearly indicated.

Scenarios were also formulated for coal utilization in future new generating capacity, assuming a medium rate of overall electrical growth with different fractions generated from coal. These were combined with scenarios for conversion of existing facilities to arrive at the range of values for 1985 and 2000 utility coal demand. For all scenarios aggregate coal energy demand is within the estimated regional supply for the corresponding (low, medium, or high) case. However, policies favoring high coal utilization could be constrained if national coal production increased at or below an average rate of about 3% per year. Added industrial demand plus demand for premium (low-sulfur) fuels could similarly affect the overall supply-demand picture, particularly in a high coal utilization case. Regional supplies by sulfur content could not be considered in the present study, although national supply levels were estimated.

Section V is a discussion of the role of coal-derived synthetic fuels in the energy future of the Northeast. For the most part, processes producing low-Btu gas, high-Btu gas, and synthetic liquids from coal will contribute to the energy supply of the Northeast indirectly by augmenting national supplies of gas, oil, and electricity. Low, medium and high production scenarios for each of these synthetic fuels are derived from a review of current national estimates, prorated according to the approximate fraction of total U.S. oil and gas used in the Northeast to obtain an estimate of the "effective" contribution of synthetic fuels to the region's energy supply. In 1985, synthetic fuels production is likely to be small; by 2000, more substantial contributions could be available if a national policy for rapid coal synthetics development were pursued.

I. INTRODUCTION

A. Background

As part of its ongoing Regional Energy Studies Program, Brookhaven National Laboratory (BNL) has undertaken to examine possible energy futures of the Northeastern United States during the remainder of this century. This effort is directed toward the development of information by which state and federal governments can assess the implications of alternative energy policies for the region, including the policy of "muddling through." The study methodology involves constructing scenarios that reflect a range of possible energy supplies and demands for the region for the years 1985 and 2000 and analyzes the options for matching energy supply and demand. The present report considers the potential for coal utilization in the region.

The Northeast region, for purposes of this study, consists of eleven states divided into four subregions: New England, New York, Pennsylvania, and the Middle Atlantic states (Figure 1). All are large consumers of energy, but only Pennsylvania has extensive natural resources, principally coal. Maryland, New York, and Pennsylvania also have small reserves of natural gas and petroleum, but these are insignificant compared with the total regional demand.

Pennsylvania is the third leading producer of coal in the nation, and coal provides a large part of the state's energy needs.[1] The location and magnitude of Pennsylvania coal reserves are shown in Figure 2. With the exception of Pennsylvania, however, coal has played a dwindling role in the Northeast energy picture during recent years. The extent to which this trend might be reversed is the principal subject of this study.

The largest potential user of coal in the Northeast is the electric utility industry, which will be the main focus in discussions of coal energy demand. Industrial demand for coal is treated in a separate report in this series. Many of the region's electric utilities have historically had coal-burning capability but have switched to oil and natural gas because of their lower costs and ability to meet environmental regulations. The following paragraphs review these recent regional as well as national trends in coal utilization to provide some perspective on the problems of increasing coal use in the future. Major options for coal utilization in the Northeast are also briefly reviewed.

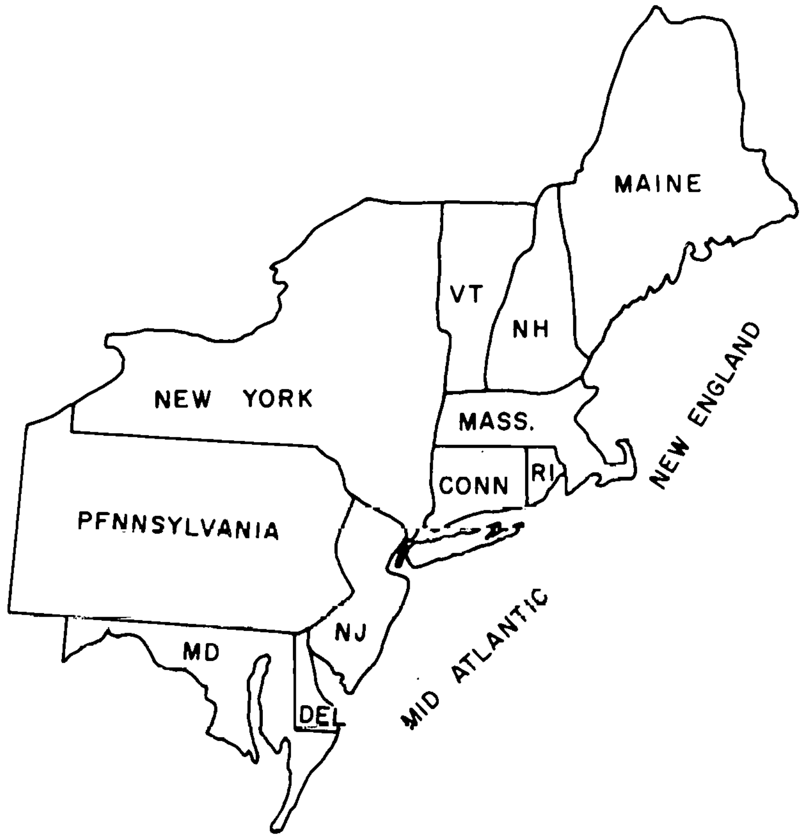

Figure 1. The Northeast region.

B. Historical Perspectives on Coal Use in the Northeast

1. Trends in Regional Coal Utilization. Earlier in this century, coal was the primary source of energy in the Northeast, as it was throughout most of the United States. After World War II coal began to be replaced by oil and natural gas as a fuel for both industrial use and electric power generation. Conversion to oil and gas accelerated in the late 1960's as a result of both economic and environmental factors (see Figures 3 and 4). In 1961, 78% of the region's electricity was generated from coal; in 1973, only 40%, a loss of half of coal's market share. If Pennsylvania is excluded, the change is even more dramatic. In 1973, 17% of the electricity in the rest of the region was generated from coal, compared with 70% in 1961.

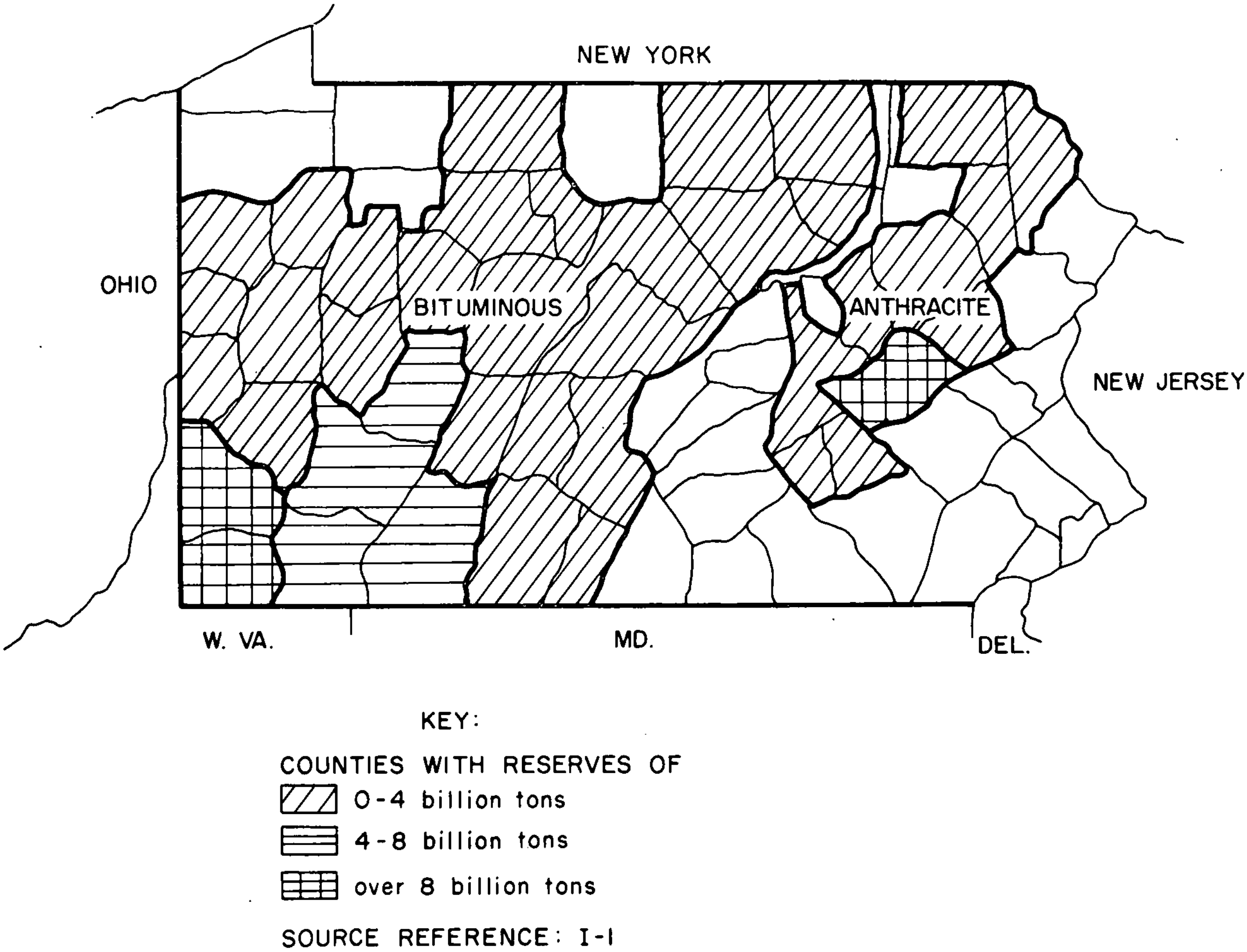

Figure 2. Pennsylvania in place coal reserves (Jan. 1972).

The reasons most often cited for this large percentage decline in coal use are the introduction of increasingly stringent air pollution emission regulations in the late 1960's and early 1970's and the changing economics of competing fuels. Figure 5 presents the historical cost of fuels for electricity generation in the region, excluding Pennsylvania, where coal is less expensive than in other parts of the Northeast. Around 1967 the delivered price of oil became cheaper than that of coal and remained so until about 1971 or 1972. This period was also the time of greatest conversion from coal to oil (see Figure 3), which suggests that utilities may have been converting to the lowest cost fuel available.

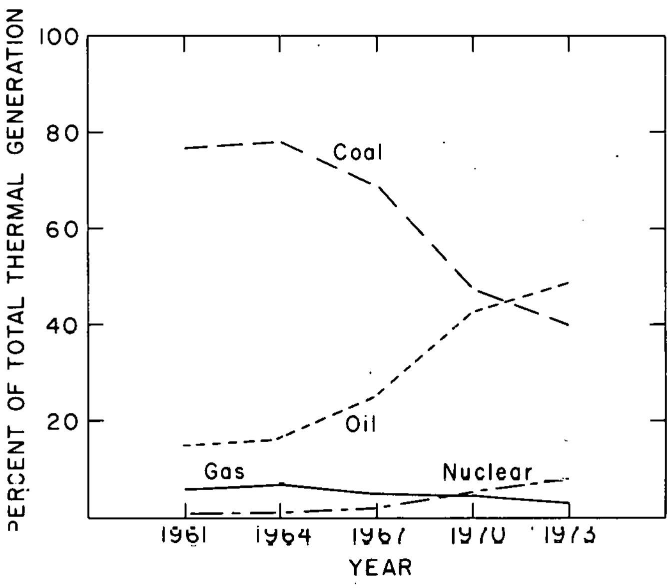

Figure 3. Historical fuel use patterns by Northeastern electric utilities.[2,3]

The 1960's, however, were also a period of growing concern over the environment. The national Clean Air Act was passed in 1963, with major amendments in 1967 and 1970. Included in the 1970 amendments was a national mandate to permanently reduce sulfur dioxide emissions, a principal source of which was the combustion of coal. Technology for the control of sulfur emissions, however, was in the very early stages of development, and supplies of sufficiently low sulfur coal were often unavailable. Thus, many utilities and industrial sources converted to cleaner fuels such as oil and natural gas. As a result, the regional decline in coal utilization was further accelerated, and today environmental regulations continue to pose a significant barrier to increased coal use in the Northeast.

2. Decline in Rail Transportation. As coal markets began to disappear, developments in mining and transportation further hampered the use of coal in the Northeast, and continue to do so despite the renewed interest in coal following the 1973 Arab oil embargo. The predominant means of transporting coal has been by railroad, and profitable rail operations today continue to derive

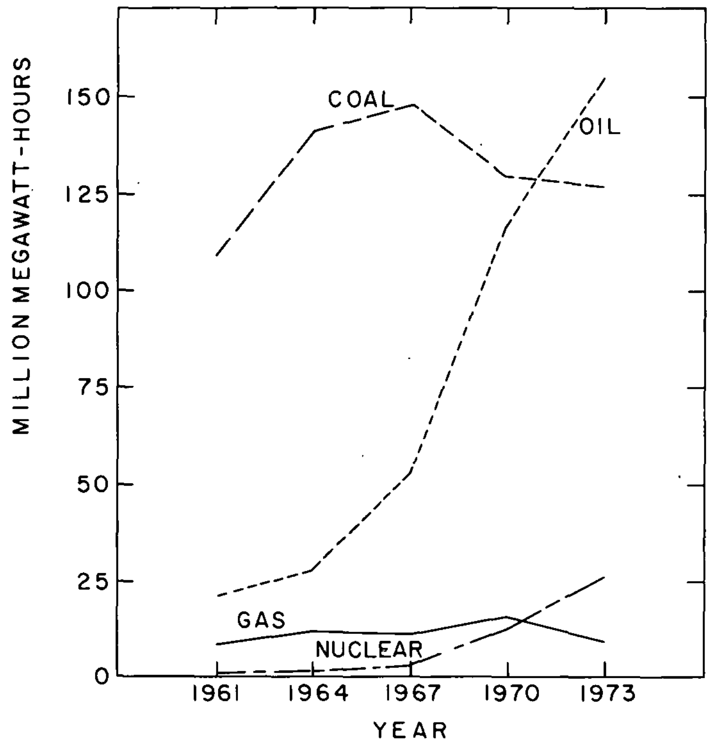

Figure 4. Historical electricity generation by type of fuel for Northeast.[2,3]

major revenues from transporting coal. Presently, however, railroads in the Northeast are in generally poor financial condition; one of the reasons for their decline has been this loss of coal revenue.

Earlier in this century, the railroads had an effective monopoly on the transportation of freight, charging high rates for freight with no alternative to rail service.[4] The appearance of competition in the 1930's and 1940's began to shift this higher priced traffic away from the railroads. Trucks began to capture much of the short- and medium-haul market, while federally constructed lock and dam facilities on major waterways produced new low-cost competition in

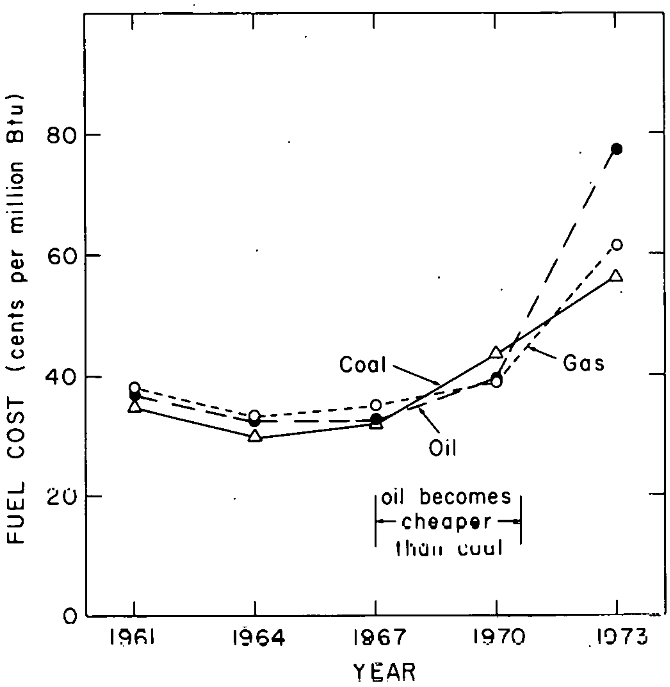

Figure 5. Historical fuel costs for electricity generation in the Northeast region (excluding Pennsylvania).[2,3]

the long hauling of bulk commodities such as coal.[5] Effectively the growth in rail track mileage in the Northeast had ended by 1910.

Other factors contributing to rail's decline included operating and management inefficiencies, adverse regulatory policies, and a general lack of innovation. During the past several years, eight railroads serving the Northeast have declared bankruptcy. In considering the potential future of coal in the Northeast region, therefore, the current and future status of the railroad system is an obviously important consideration. This is elaborated upon in Section III.

3. Trends in Coal Production and Productivity. U.S. coal mining capacity and annual production rates have remained virtually unchanged for the past several years following a decade of continual growth at about 5% a year between 1961 and 1970 (Figure 6). Since 1970, there has been a rather abrupt leveling

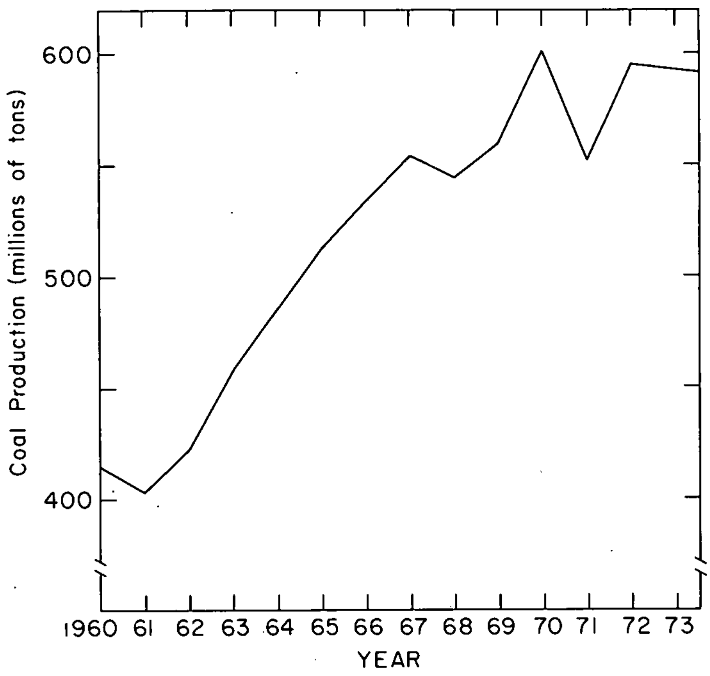

Figure 6. Recent trends in U.S. coal production (1960 - 1973).[6]

off, which, as in the case of transportation, has not been due entirely to a decreased demand for coal. Production has remained stagnant despite an increase in demand, which in 1973 amounted to about 17 million tons more than could be supplied.[7]

This leveling of coal production in the face of increasing demand may be attributed in part to recent shifts in the economic and institutional environment of coal mine operations. Recent labor renegotiations have led to a rapid increase in mining costs, especially for underground operations. In many areas chronic shortages of trained manpower limit mining capacity. Recent decreases in labor productivity (Figure 7), caused in part by enactment of the 1969 Coal Mine Health and Safety Act, further limited the industry's capacity to remove coal from the ground. While the development of new mining technology and safety equipment will eventually reverse this decline, labor constraints can be expected to limit mining capacity in the short term.

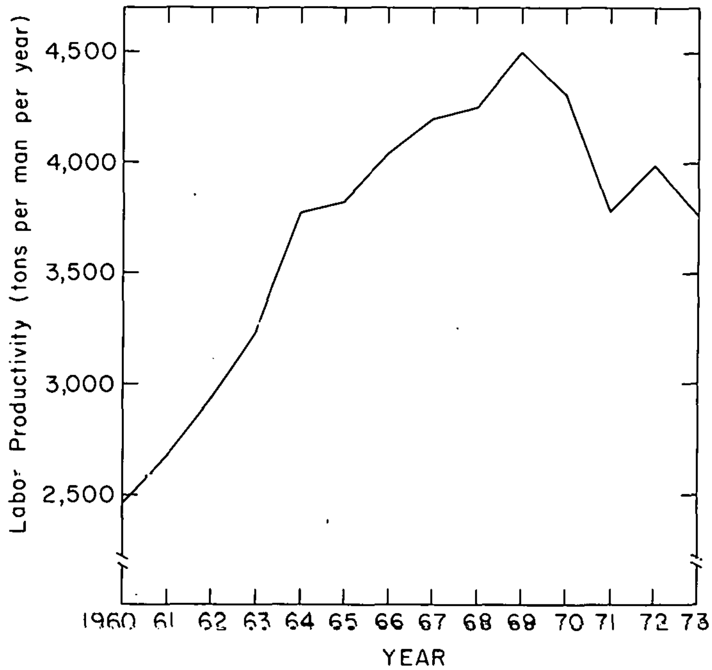

Figure 7. Recent trends in the productivity of U.S. coal labor (1960 - 1973).[8]

Inflation and shortages in the mining equipment supply industry have also constrained recent production levels. Expansion in the coming years may depend on the ability of suppliers to meet demands for equipment. While these demands will probably be met, it will be at a higher price and with longer delivery times than in the past.

C. Future Options for Coal Use

The supply and transportation constraints noted above will affect the rate at which U.S. coal production can respond to changes in national and regional markets for coal over the coming years. In the past, the coal industry has been able to gear up to meet increased demands, and the rail system has been able to transport the coal from mine to market. This could happen again if the demand for coal is sufficiently strong and enduring. Indeed, both the coal industry and the transportation industry appear to be seeking a long-term commitment for their product.

The basic question in determining the potential for coal utilization in the Northeast, therefore, is: Can coal be economically utilized in compliance with environmental standards, especially those for sulfur dioxide? Technological options for coal utilization in the Northeast include several systems already available, as well as new technologies likely to become commercial in the future. Available technologies include coal preparation, a means of reducing the sulfur and ash content of coal prior to combustion, and flue-gas desulfurization (FGD), which removes sulfur dioxide following combustion. Coal preparation increases the supply of low sulfur coal and can be used with conventional particulate control equipment where sulfur dioxide emission regulations permit use of coal with more than about 1% sulfur. FGD systems can meet more stringent emission regulations, but their implementation may not be feasible because of cost and/or ancillary problems such as solid waste disposal. Small coal gasifiers, prevalent early in this century, are another available technological option for industrial utilization of coal, but are often uncompetitive at current prices.

Advanced technologies under development for commercialization in the 1980's and 1990's included processes for direct and indirect utilization of coal. Fluidized-bed boilers and combined-cycle electric generating plants use coal directly and avoid the sulfur dioxide problem by converting sulfur to other forms more amenable to treatment.

Indirect coal utilization refers to the conversion of coal to synthetic liquid and gaseous fuels, which substitute for conventional supplies of clean energy. In this case, the environmental problems of coal are shifted to the coal conversion plant, where they are thought to be more manageable. Since high-Btu gas and liquefaction plants would probably be located at the source of coal supply, the principal benefit to the Northeast from coal conversion would arise from the additional supplies of synthetic crude oil and gas that would become available nationally. On the other hand, low- or medium-Btu gas processes could be located in the region and would supply substitute boiler fuel for utility and/or industrial use. In all cases, the practicability of any of the advanced techniques will depend heavily on the economic as well as technological feasibility of competing processes.

The remainder of this report will outline some of the main issues which will influence the region's ability to utilize coal over the next 25 years and suggest quantitative bounds on potential regional coal use for the milestone years 1985 and 2000. The purpose of this study is not to predict what the future use of coal will be. Rather, it is to present a range of possibilities associated with alternative national and regional coal policy. The relationship of coal to other regional energy sources will be discussed in the Perspectives Study summary report.

II. SCENARIOS FOR FUTURE COAL SUPPLY

A. Introduction

The first of many factors affecting the magnitude of future national coal production and supply to the Northeast region is the limitation on the resource itself. If no resource constraint exists in the foreseeable future, the ability to utilize coal will depend on mining capability, transport capacity, and market demand. Table 1 lists the estimated recoverable coal reserves for each Bureau of Mines Coal District (locations shown in Figure 8). Total recoverable coal reserves in the United States are estimated at 427 billion tons, which would last for 330 years at 1974 production rates, assuming about 50% recovery of reserves (assuming present mining technology). Even under the highest estimates of future coal production, therefore, a resource constraint within the time frame considered here (1975-2000) is unlikely.

In a non-resource constrained market, the amount of coal actually supplied is highly dependent on demand and price, and these factors must be included in any assessment of potential future coal supplies. Similarly, the future supply and quality of coal available to the Northeast region will depend on the price it is willing to pay (including premiums for lower sulfur coal and higher transportation costs) relative to prices offered by other domestic and foreign markets. In this study no attempt is made to explicitly characterize the economics of future regional markets for coal. Rather, several possible scenarios of future coal supply to the Northeast are presented, ranging from a low supply case with little coal industry growth to a high supply case in which coal production and utilization are strongly revitalized.

B. Current National Supply Estimates

The three interrelated constraints in scenarios for future U.S. coal production are mining surge capacity, transportation availability, and market demand. If it is assumed that transportation capacity and market demand exist for all coal that can be produced, the limiting factor in increasing production is the surge capacity of the coal industry, defined as the maximum attainable increase in mining production from one year to the next. Most estimates for

Table 1

U.S. BITUMINOUS COAL RESERVES BY U.S. BUREAU OF MINES DISTRICT AS OF JANUARY 1, 1974[9]

(thousands of tons)

District	Strippable Reserves	Recoverable By Underground Mining	Total
1	641,950	8,859,100	9,501,050
2	634,860	15,484,400	16,119,260
3	1,343,320	14,159,490	15,502,810
4	3,653,890	17,423,260	21,077,150
5	560	117,640	118,200
6	78,140	3,724,470	3,802,610
7	867,650	3,751,380	4,619,030
8	7,243,560	24,909,290	32,152,850
9	3,904,020	8,719,890	12,623,910
10	12,222,860	53,441,860	65,664,720
11	1,674,080	8,948,490	10,622,570
12	0	2,884,860	2,884,860
13	1,272,350	1,928,220	3,200,570
14	375,360	581,240	956,600
15	8,395,670	6,658,530	15,054,200
16	0	2,230,290	2,230,290
17	1,007,720	12,177,340	13,185,060
18	2,470,580	1,697,970	4,168,550
19	23,673,930	27,553,870	51,227,800
20	262,000	3,780,460	4,042,460
21	16,431,000	0	16,431,000
22	42,561,930	65,165,030	107,726,960
33	7,907,430	5,693,990	13,601,420
Total	136,622,860	289,891,070	426,513,930

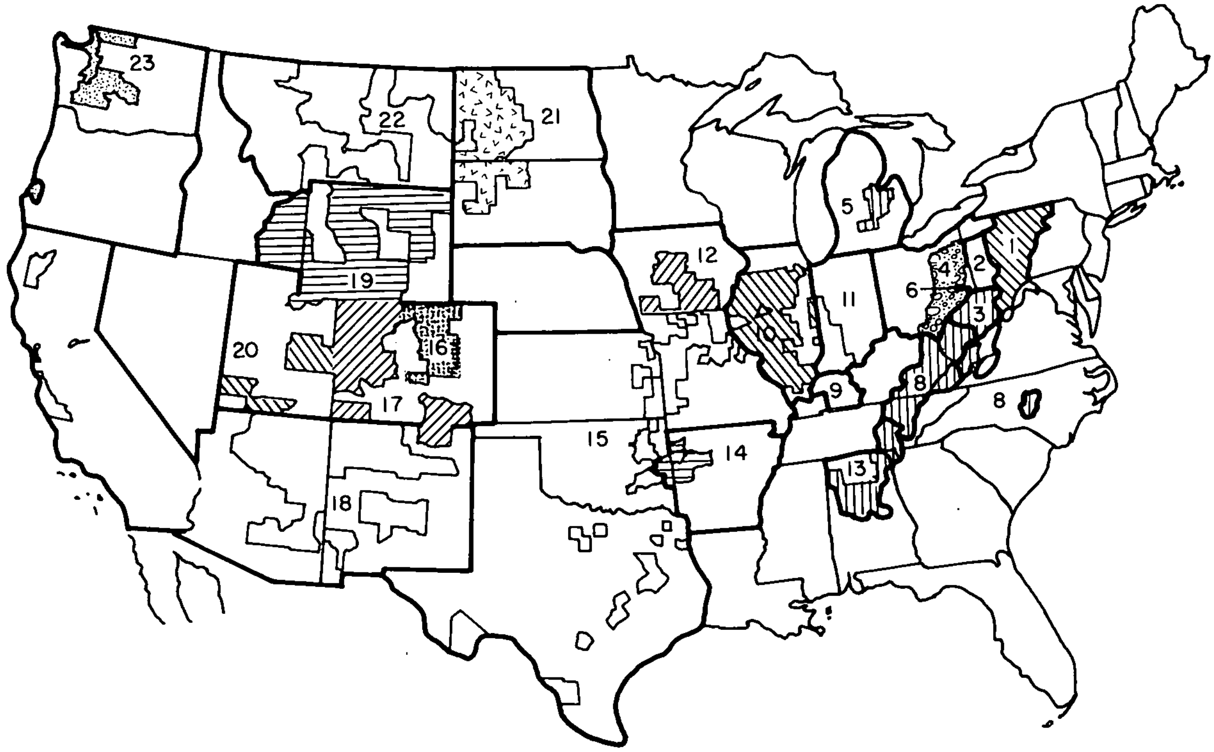

Figure 8. Coal fields of the United States by
Bureau of Mines production districts.

the domestic coal industry suggest a present surge capacity of ∿8% of total production.[10]

The estimates of national coal production in 1985 and 2000 used in this report to derive future regional scenarios for the Northeast are briefly described below. Further details can be found in the appropriate references.

1. Project Independence Estimates. One of the most comprehensive efforts to date estimating future national coal production is the Federal Energy Administration's Project Independence Blueprint Coal Task Force Report,[11] which estimates coal production by Bureau of Mines Coal District and type of mining through the year 1990.

The two scenarios developed in the PI report are the "Business-as-usual" (BAU) and "Accelerated" (ACC) coal supply scenarios. The BAU scenario assumed no significant immediate expansion in production capability because of the long lead times required for mine development and equipment deliveries.

For the longer term, it was assumed that capital would be available for new mines already planned or under development and that the development and installation of stack-gas scrubbers would be accelerated to permit the use of higher sulfur coals. The availability of adequate manpower and transportation was also assumed. From a policy point of view, the BAU scenario assumed that no major legislation would disrupt recent upward trends in surface mine production and that surface-mined coal would represent a larger proportion of future coal production. Some redistribution of coal according to the stringency of air quality emission standards was also assumed. A study by the Mitre Corporation for the Department of the Interior[9] analyzes the actual constraints to be overcome in meeting the BAU and ACC scenario projections.

The ACC supply scenario assumed some relaxation of historical constraints on the production and use of coal, including relaxation of air quality regulations, granting of variances, leasing of public lands as needed, and no serious limitations on surface mining. The ACC scenario also assumed no signficant capital, manpower, equipment, or transportation limitations, and accelerated research and development on advanced technologies utilizing coal. In both PI scenarios, the Task Force relied heavily upon judgment and knowledge of the industry to arrive at their projections. In determining future expansion within a given region, a major factor was the desirability of the coal of that region in terms of its sulfur content. Production estimates were then made based on depletion of existing underground and surface mines, as well as on development of new mines.

Since production scenarios in the Project Independence study only extended to the year 1990, extrapolations of the PI estimates were performed to derive scenarios for the year 2000. The first was a linear extrapolation of the 1985-1990 annual growth rates of 3% in the BAU scenario and 5.3% in the ACC scenario. This assumes a constant rate of growth for the coal industry between 1985 and 2000 for both scenarios. For the BAU case this is believed to be reasonable, since the surge capacity of the coal industry is likely to increase under moderately favorable conditions.

For the ACC case, however, a linear extrapolation probably yields an unreasonable upper bound, since it implies that the coal industry must sustain a high rate of growth for 25 years, from 1975 to 2000. Also, the coal production level achieved would amount to nearly two-thirds of the total U.S. energy demand forecast for 2000, which would imply an unfeasibly large shift to coal. Thus, a second extrapolation was developed which assumed only a 3% rate of growth between 1985 and 2000 for the ACC scenario. This 3% growth rate is considered to be easily sustainable over a prolonged period.

2. National Petroleum Council Estimates. In 1971 the National Petroleum Council (NPC) undertook a study of the energy outlook for the United States up to the year 1985. Results of the study included a Coal Task Group report that presented a detailed outlook for future coal availability.[12] Since the NPC study was completed before the 1973-74 Arab oil embargo (with its subsequent oil price increases and calls for energy self-sufficiency), their estimates are generally more conservative than those of Project Independence.

The NPC based their future national coal production estimates on three constant growth rates for the coal industry, 3%, 3.5%, and 5%, corresponding to what NPC believed were realistic possibilities for the coal industry at the time of their study. These growth rates also approximated historical growth rates in the coal industry. The NPC 1985 supply estimates were thus obtained by compounding actual 1972 production rates at each of the three annual growth rates assumed.

In the present report, it was assumed that these same growth rates would apply after 1985. This methodology may result in relatively conservative estimates, at least for the 3% and 3.5% cases, because of possibly favorable changes in technology and public policy resulting from the 1973 embargo and subsequent national stimulus toward energy self-sufficiency.

3. Energy Research and Development Administration Scenarios. As part of its long-range energy planning function for the Energy Research and Development Administration (ERDA), BNL has estimated coal production in 1985 and 2000 for six different scenarios.[13] These estimates were obtained by optimizing BNL's national energy model to satisfy all end-use demands at minimum cost, subject to constraints on energy resource supply and technological capabilities.

4. National Academy of Engineering Estimate. A study done by the National Academy of Engineering (NAE) in 1974 presented what was believed to be a realistic possibility for coal production in 1985.[14] The NAE estimate was based on an assumed capability of the coal industry to expand annual mine production by about 660 million tons/year over the next ten years. This represented a surge capacity

of 10% over 1974 production, yielding a production rate of 1.26 billion tons/year for 1985, subdivided as shown in Table 2.

Table 2

NATIONAL ACADEMY OF ENGINEERING

COAL PRODUCTION ESTIMATES[14]

Coal Supply Region	Source	1985 Production (10^6 Tons/Year)
Eastern	Underground mining	480
Eastern	Surface mining	220
Western	Surface mining	560
Total		1260

5. Ford Foundation Scenarios. The Ford Foundation considered three major scenarios based on the historical growth rate, a "technical fix" case (which assumed increased end-use efficiencies), and a case of zero energy growth.[15] Several alternatives were considered in each scenario. For comparison with other estimates, the present study looks at the lowest coal supply under the technical fix scenario, the medium coal supply in the technical fix scenario, and the highest coal production in the historical growth scenario.

6. Synthetic Fuels Commercialization Program Scenarios. Another recent set of estimates of feasible future national coal supply has emerged from the national energy modeling effort conducted by Stanford Research Institute (SRI) as part of the federal Synthetic Fuels Commercialization Program (SFCP).[16] The main purpose of this project was to study the availability and price of various energy forms as they affect the future supply of synthetic fuels. Although a wide variety of alternative scenarios were considered, we have again chosen three coal supply cases representing low, medium, and high levels predicted by the SRI model: (a) high cost of producing coal, (b) high domestic oil and gas availability with high import prices, and (c) low cost of coal production.

C. Scenarios for U.S. Supply in 1985 and 2000

Table 3 presents a comparison of the U.S. coal supply estimates discussed above, using 1973 as the base year. For the NPC and PI estimates, intermediate year projections were available and are shown in Figure 9. Note the large variance between the lowest case (NPC 3% growth) and the highest (PI-ACC).

Table 3

COMPARISON OF NATIONAL COAL SUPPLY ESTIMATES

(10^6 tons/yr)

Coal Supply Case	1985	2000
NPC 3% growth	870	1360
NPC 3.5% growth	930	1560
NPC 5.0% growth	1120	2340
PI-BAU (linear extrapolation after 1990)	1100	1700
PI-ACC (linear extrapolation after 1990)	2060	4200
PI-ACC (3% growth after 1985)	2060	3210
ERDA O - No new initiatives in end use	1010	1610
ERDA I - Improved end-use efficiencies	880	1090
ERDA II - Coal and shale synthetics	1110	2370
ERDA III - Intensive electrification	960	1450
ERDA IV - Limited nuclear power	950	2180
ERDA V - Combination of all technologies	860	1860
NAE - Expected product	1260	--
FORD Foundation - Historical growth, high nuclear	920	1760
FORD - Technical fix, base case	720	1000
FORD - Technical fix, high nuclear	560	680
SRI - High coal cost	600	1280
SRI - High oil and gas availability	680	1720
SRI - Low coal cost	920	2280

Figure 9 and Table 3 suggest consideration of the NPC 3% as a low growth case, the PI-BAU as a medium growth case, and the PI-ACC with 3% growth after 1985 as a high case. The two PI blueprint scenarios break down the production estimates up to 1985 by individual producing districts (see Figure 8), whereas all other projections report only national aggregate figures. Selection of a high production case for the year 2000 was based on a modification of the PI-ACC

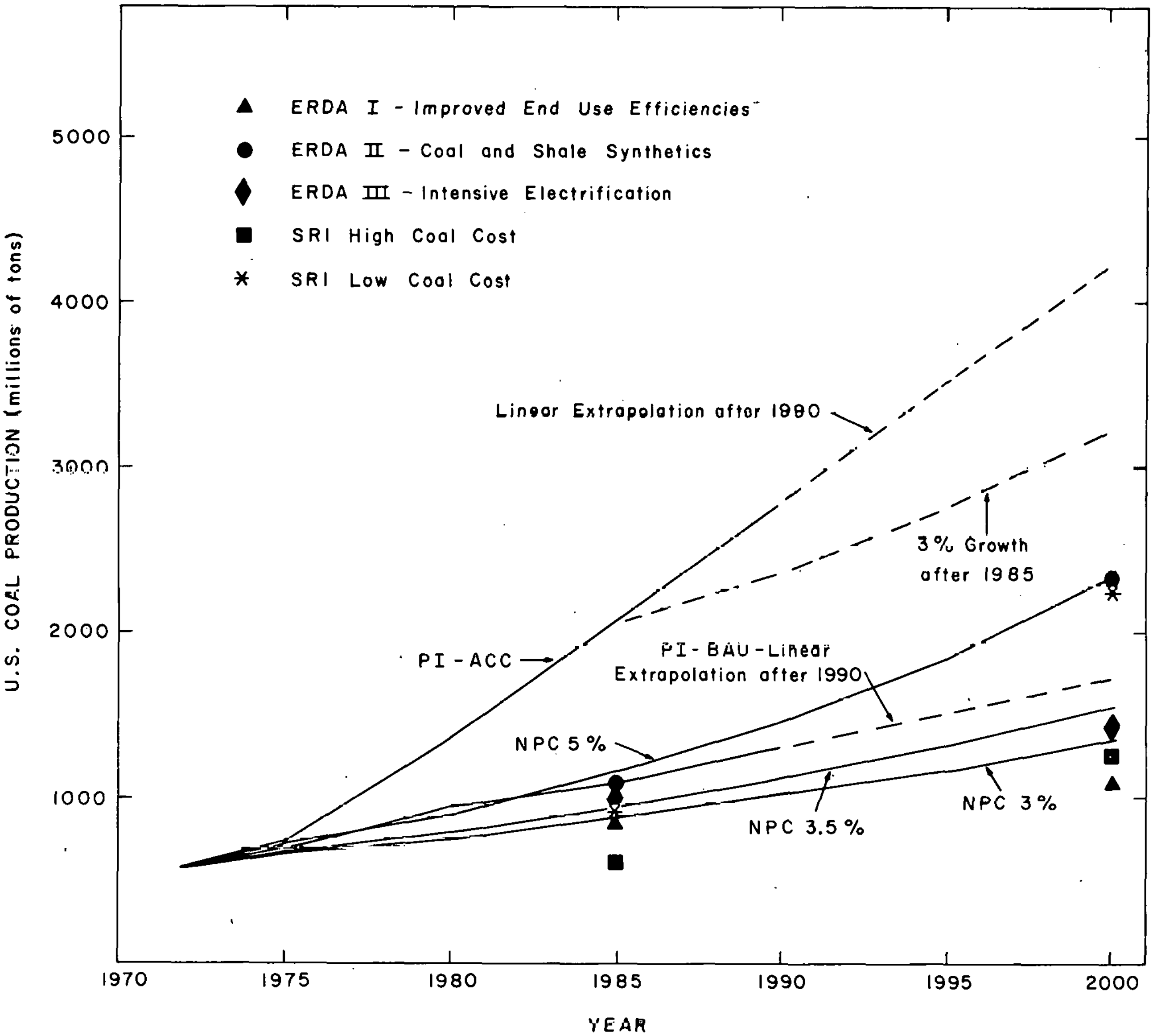

Figure 9. Comparison of national supply estimates.

scenario. The PI-ACC case assumed immediate and sustained acceleration of production which, if linearly extrapolated to 2000, would yield 4.2 billion tons of coal per year with an energy equivalent of ∿ 105 quads (10^{15} Btu's). ERDA has estimated total U.S. energy demand in 2000 to be between 120 and 165 quads.[13] Thus, a linear extrapolation of PI-ACC coal production would account for between 65% and 85% of total U.S. energy demand, considered unrealistic even for a high production scenario. For this reason, the PI-ACC case with a 3% growth rate after 1985 was chosen as the high supply case. This still assumes significant intensification of coal production in the near future, but a slower rate of growth later on, similar to recent historical rates. A constant 3% growth rate from 1972 provided the low supply scenarios for 1985 and 2000. A more thorough development of the supply projection methodology is presented in Appendix A.

1. <u>Future Coal Exports</u>. To determine coal availability to the Northeast region, an estimate is needed of the magnitude of future coal exports. If it is assumed that future exports will be limited principally to coking coal, then, according to NPC,[12] 1985 coal exports will reach 120 million tons and year 2000 exports will be 175 million tons. In Appendix A, these export levels are apportioned to coal supply districts in the same ratio as the 1974 distribution of coking coal exports.

2. <u>Sulfur Content of Future Coal Supplies</u>. Sulfur content determines to a great extent where coal can be burned, how much environmental control (e.g., coal preparation or stack-gas scrubbing) will be necessary, and what the potential of coal as a substitute for cleaner fuels will be. Related to this is the energy content or Btu value of coal. A low sulfur western coal, for example, contains less energy per pound than eastern coals with higher sulfur levels. Thus, greater tonnages are required to produce the same amount of useful energy. Furthermore, sulfur content per million Btu of heat input often determines whether coal can be utilized in compliance with sulfur dioxide emission regulations. Here, an eastern coal would generally be superior to a western coal of equivalent sulfur content.

A rough estimate of the availability of coal in various sulfur content categories for 1985 was obtained by dividing total 1985 production estimates into categories in the same proportion as actual district production levels in 1970, the most recent year for which complete information was available.[17] Since no estimates existed of individual district production in the low supply (NPC 3%) case, it was assumed that all districts would have the same relative growth rates as in the BAU (medium supply) scenario. The constraint set was that the total national production in each year was 3% greater than in the previous year. Table 4 presents the estimates derived in this fashion. For any given production

Table 4

PROJECTED 1985 COAL PRODUCTION

(10^3 TONS) IN VARIOUS SULFUR CONTENT CATEGORIES[a]

Region of Origin	≤0.5	0.6-1.0	1.1-1.3	1.4-1.8	1.9-3.0	>3.0	Total (10^6 tons)
Northern Applachia							
Low supply	30	23,380	16,120	32,100	82,210	56,560	210,400
Medium supply	30	26,610	18,850	37,020	94,670	66,170	243,350
High supply	60	50,650	36,470	71,060	178,050	122,910	459,200
Southern Appalachia							
Low supply	12,410	223,120	17,210	27,760	16,130	2,470	299,100
Medium supply	15,420	278,560	21,700	34,920	20,460	3,090	374,150
High supply	28,590	514,870	39,870	64,180	37,520	5,670	690,700
Midwest							
Low supply	0	6,440	1,600	5,260	29,410	134,190	176,900
Medium supply	0	7,420	1,850	6,130	34,480	156,020	205,900
High supply	0	14,000	3,490	11,360	63,160	289,890	381,900
Near West							
Low supply	880	1,900	0	9,500	280	29,740	42,300
Medium supply	1,340	2,620	0	14,400	420	45,020	63,800
High supply	2,460	4,770	0	26,370	750	82,450	116,800
Far West							
Low supply	29,630	101,670	12,630	750	620	0	145,300
Medium supply	43,390	148,900	18,490	1,110	910	0	212,800
High supply	84,500	289,960	36,010	2,150	1,780	0	414,400
Total U.S.							
Low supply	42,950	356,510	47,560	75,370	128,650	222,960	874,000
Medium supply	60,180	464,110	60,890	93,580	150,940	270,300	1,100,000
High supply	115,610	874,250	115,840	175,120	281,260	500,920	2,063,000

[a]Based on data from Appendix A.

level, these figures are likely to be conservative in the lower sulfur ranges, since the 1970 base year does not reflect the subsequent demand for low sulfur coal. However, the range of production levels reported may give some clue as to future production in sulfur content categories.

To estimate energy available from future production as a function of sulfur content, heat (Btu) values for future production were calculated from the mean energy content of coal reserves in each of the supply regions considered. These mean heat values (Table 5) were multiplied by the tonnage estimates in Table 4 to determine the approximate Btu values of future coal production for each of the three scenarios. The resulting energy values are presented by supply region and sulfur content category in Table 6.

Table 5

MEAN HEAT VALUE OF COAL BY SUPPLY REGION[11]

Coal Supply Region	Estimated Mean Btu/lb (As Received)
Northern Appalachia (Districts 1 to 6)	12,300
Southern Appalachia (Districts 7, 8, 13)	13,000
Midwest (Districts 9, 10, 11)	11,000
Near West (Districts 12, 14, 15)	11,000
Far West (Districts 16 to 23)	9,600

For the year 2000, no attempt was made to estimate production by sulfur content category because of the many uncertainties involved in future technology for mining and end use. Estimates of the SRI model, however, indicate comparable quantities of "high sulfur" (eastern) and "low sulfur" (western) coal in use by 2000 for a "medium case" scenario.[16]

<u>Table 6</u>

ENERGY CONTENT (10^{15} Btu) of 1985
ESTIMATED COAL PRODUCTION IN VARIOUS SULFUR CONTENT CATEGORIES[a]

Region of Origin % S:	≤0.5	0.6-1.0	1.1-1.3	1.4-1.8	1.9-3.0	>3.0	Total
No. Appalachia							
Low Supply	0.01	0.58	0.40	0.79	2.02	1.38	5.19
Medium Supply	0.01	0.65	0.46	0.91	2.33	1.63	5.99
High Supply	0.01	1.25	0.90	1.74	4.38	3.03	11.31
So. Appalachia							
Low Supply	0.33	5.80	0.45	0.72	0.42	0.07	7.79
Medium Supply	0.40	7.24	0.56	0.91	0.53	0.08	9.72
High Supply	0.75	13.38	1.04	1.55	0.97	0.15	17.95
Midwest							
Low Supply	0	0.14	0.03	0.11	0.65	2.95	3.88
Medium Supply	0	0.16	0.04	0.14	0.76	3.43	4.53
High Supply	0	0.30	0.08	0.25	1.39	6.38	8.40
Near West							
Low Supply	0.02	0.05	0	0.21	0.01	0.65	0.94
Medium Supply	0.03	0.06	0	0.32	0.01	0.99	1.41
High Supply	0.05	0.11	0	0.58	0.02	1.81	2.57
Far West							
Low Supply	0.57	1.95	0.24	0.02	0.01	0	2.79
Medium Supply	0.83	2.86	0.35	0.02	0.02	0	4.08
High Supply	1.62	5.57	0.69	0.04	0.03	0	7.95
Total U.S.							
Low Supply	0.93	8.52	1.12	1.85	3.11	5.06	20.59
Medium Supply	1.27	10.97	1.41	2.30	3.65	6.13	25.73
High Supply	2.43	20.61	2.71	4.27	6.79	11.37	48.18

[a]Based on Tables 4 and 5.

D. Northeast Regional Coal Supply

In developing a perspective on the future supply of coal available to the Northeast, it is assumed that the Northeast will receive the same share of national district production in the future as it does at present (1974). When coupled with the earlier national scenarios of district-by-district production levels, a range of values for the Northeast is obtained. This does not imply a constant percentage of total national production, since each district's supply is different. In the high supply case, for example, national production increases predominantly in western districts, which supply very little coal to the Northeast. Hence, the region's fraction of total U.S. supply would be less than at present. In general, all high supply estimates are believed to overstate the direct coal supply since they assume substantial development of the coal conversion industry.

The true future coal supply will be determined by technical constraints, public policies, and market forces, which at present are such that utilities in the Northeast generally pay the highest prices in the country for fuel (Table 7). Presumably the region could capture a larger market share of future eastern low sulfur coal production or coal-derived energy if it were willing to pay a premium for these fuels. This could be a plausible situation in view of existing high oil and gas prices, reliance on foreign sources, and current federal policy regarding conversion from oil to coal.

1. Scenarios for 1985. The existing regional fraction of total national production distributed to the Northeast was derived from 1974 data published by the U.S. Bureau of Mines.[19] 1974 coal flows from USBM production districts (Figure 8) to individual states for consumption were used to establish the fraction of each district's production shipped to a given state. These fractions were then applied to the three scenarios for each district's 1985 production levels. State-by-state supply estimates were then aggregated. A detailed description of the data and methodology used to derive the regional coal supply appears in Appendix B.

No attempt was made in this report to characterize the sulfur content of future coal supplies available to the region. The national distribution data shown in Tables 4 and 6 indicate sizable reserves and potential production levels of low sulfur coal, so that significant departures from the existing distribution

Table 7

AVERAGE 1974 PRICE ($\$/10^6$ BTU) OF FUELS PURCHASED BY ELECTRIC UTILITIES[18]

Region	Coal	Oil	Gas
New England	1.14	1.97	1.29
Middle Atlantic	0.86	2.06	0.68
East North Central	0.70	1.73	0.77
West North Central	0.45	1.79	0.42
South Atlantic	0.97	1.78	0.59
East South Central	0.59	1.80	0.60
West South Central	0.17	1.88	0.43
Mountain	0.26	1.85	0.52
Pacific	0.37	2.01	0.59

patterns are feasible. Such departures will depend principally on whether or not the Northeast region will be willing to pay a premium for low sulfur coal in the light of other regions' demands and the price of alternative fuels. At the same time, technology for burning high sulfur coal should also become more widely available by 1985, which will permit higher sulfur coals to be utilized in the Northeast. Possible demand for coals of different sulfur levels is discussed in Section IV.

Three scenarios of 1985 coal supply for the Northeast region are summarized in Figures 10 and 11 in terms of coal tonnage and energy content. A comparison of these figures with utility coal demand estimates (Section IV) make it clear that, from an energy resource point of view, available regional coal supplies should be sufficient to meet the maximum demands of the Northeast in 1985. However, important transportation and utility constraints must also be considered. These are discussed in Sections III and IV.

2. Scenarios for 2000. The approach taken in deriving regional supply scenarios for the year 2000 was similar to that for 1985. Here, however, estimated USBM District production levels for 1985 and 1990 were extrapolated by using the same growth rate assumed for total national production, and estimated exports from each district were then subtracted. Again, 1974 distribution data

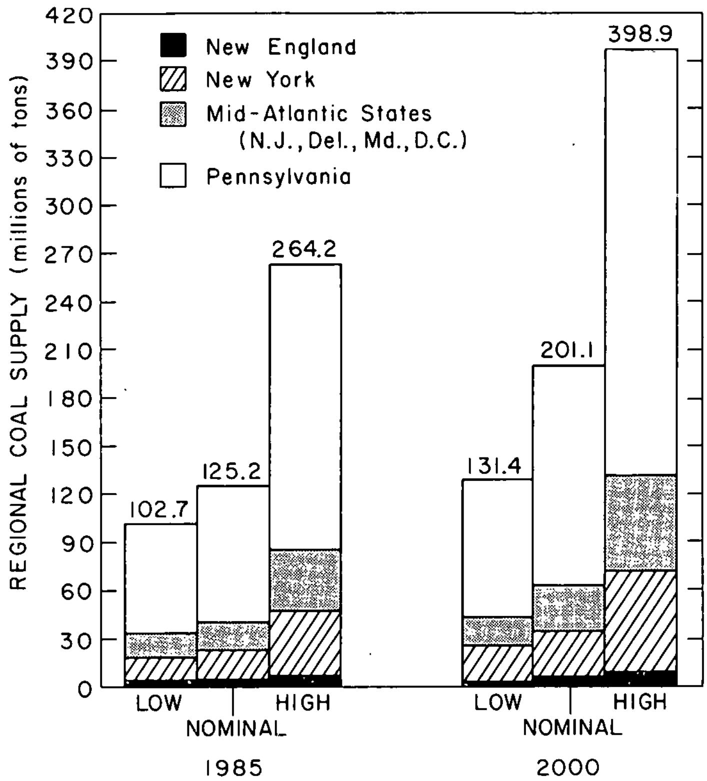

Figure 10. 1985 and 2000 coal supply scenarios for the Northeast region.

from district of production to state of consumption were used to prorate future district production to states of the Northeast. From this, coal supply was again aggregated for the region (see Appendix B). To convert future tonnage into energy values, the heat values of Table 5 were applied to 2000 production. The resulting regional supply kept in mind that the high supply case is considered overly optimistic in terms of direct coal supply to the region. A comparison of the regional coal supply estimates in Figure 10 with estimates of demand in Section IV again shows that available coal supplies will probably exceed demand, except in the case of a nuclear moratorium and large-scale coal intensification by the region's electric utilities. Actual future coal supplies to the region will depend heavily on market and policy factors, and the supply scenarios given here are intended only to establish a range of possibilities.

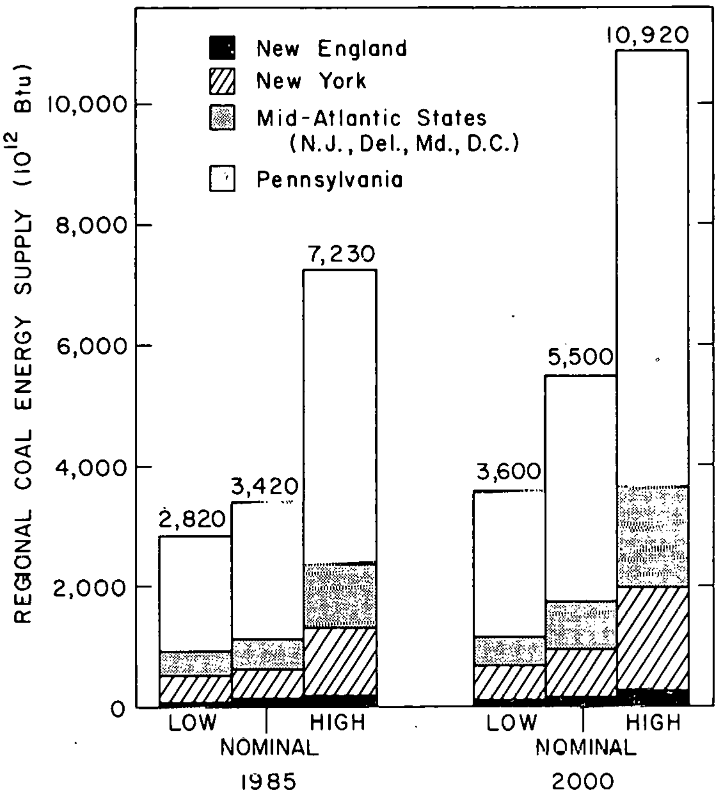

Figure 11. 1985 and 2000 coal energy scenarios for the Northeast region.

3. Other Potential Coal Supplies. In 1974, several electric utilities in the Northeast purchased coal from Western Europe. As a potential long-term source of energy, however, coal imports are not considered a feasible option, given the vast domestic resources and the foreseeable increase in the needs of current foreign suppliers, especially in Europe.

A much more promising option for the Northeast is regionally available anthracite coal. This high quality, low sulfur coal is found in northeastern Pennsylvania and the Narragansett Basin of Massachusetts and Rhode Island. The location of the Pennsylvania anthracite resources is shown in Figure 2. It is estimated that Pennsylvania has 16 billion tons of recoverable anthracite reserves.[1] Narragansett Basin reserves are currently estimated at ∿ 400 million tons.[20] At present there is no mining industry in the Narragansett area, and the long lead time required to attract capital and open new mines makes it doubtful that any significant production could occur before 1985. Estimates of possible future production levels contain many uncertainties, although programs to refine them are in progress. Conceivably, the Narragansett Basin could represent a valuable source of indigenous coal energy in New England toward the end of the century.

The potential of Pennsylvania anthracite to augment the energy supplies of the Northeast region is probably most significant in the short run. At one time the Pennsylvania anthracite industry rivaled the bituminous coal industry in production capability. Lately its role has declined, principally because of the loss of markets accompanying the general decline in coal. Should new markets develop as a result of the energy crisis, anthracite could again play an important role in the region. The Pennsylvania Governor's Energy Council is taking an active interest in revitalizing the industry.

The only available estimates of future anthracite production and use are those in a recent study by Berger Associates.[21] Here, a survey of potential users of anthracite (principally electric utilities) resulted in the development of a future supply curve, shown in Figure 12. The initial reaction to these estimates suggests that they are very conservative.[22] Approximate supply in 1985 would be 14 million tons, or $<$ 2% of the estimated bituminous supply, even for the low 3% growth case. Thus, although anthracite production could at least double, it is not likely to again become a major source of energy in the region.

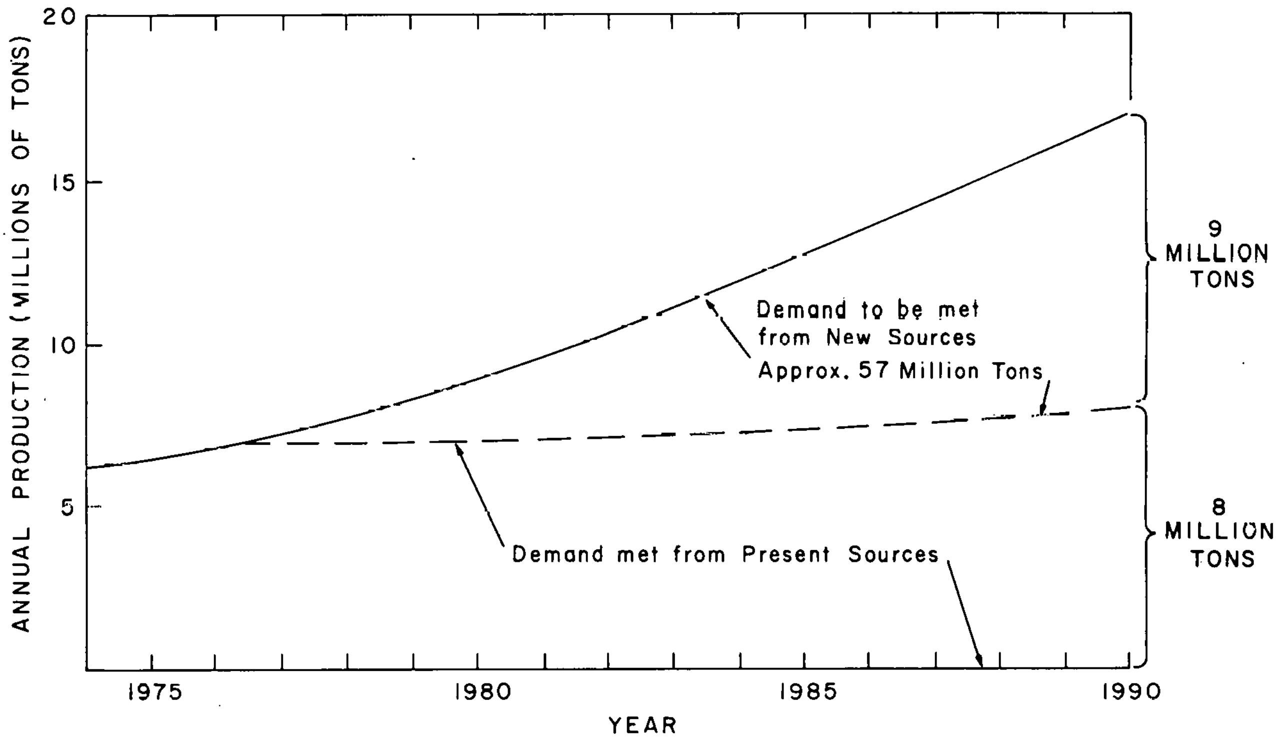

Figure 12. Projected anthracite supply to 1990.[21]

III. TRANSPORTATION CONSIDERATIONS

A. Introduction

A critical constraint to increasing the supply of coal to the Northeast may be the capacity of the coal transportation network. The economics of coal transportation will depend on the amount of coal shipped, distances traveled, and the availability of waterways and rail lines in the region. For short distances, trucking is also economical, although in the Northeast it is important principally in the coal producing regions of Pennsylvania. Possible alternative means of coal transport include coal slurry pipelines, coal synthetics pipelines, and long-range transmission of coal-generated electricity over extra-high-voltage (EHV) transmission lines. These options are discussed later in this section.

For the short term, the Northeast will have to rely on the existing transportation network. It is estimated that at one time as much as 52 million tons of coal moved to markets in New England and the Middle Atlantic States; present markets require only 15 to 20 million tons.[23] Table 8 presents the 1974 breakdown by mode of coal distribution in the region. Rail is by far the predominant mode, responsible for 45% of the total distribution in the Northeast. The decline of coal markets in the region has hit the railroad industry hard, contributing to financial insolvency of several lines as well as physical deterioration of the roadbeds and trackage. For example, in 1974, 23% of national coal production distributed by rail was carried by bankrupt railroad companies, almost all of them serving the Northeast region.[24] Thus, in their present condition, the railroads must be considered a potential constraint in the revitalization of coal in the Northeast.

B. Potential of the Northeast Rail System To Meet New Coal Demands

The Regional Rail Reorganization Act of 1973 established the United States Railway Association (USRA). This agency was designed to plan and finance the restructuring of the rail system, and the Consolidated Rail Corporation (Con-Rail), which was to operate at least part of the restructured system. The Act provided for the abandonment of uneconomical service and subsidies for bankrupt companies until the restructured system became operative. A series of studies

Table 8

COAL DISTRIBUTION IN 1974

BY MODE OF TRANSPORT[19]

Region	Coal Shipments (10^3 tons)	% of Total
New England		
Rail	1,487	72.4
River & Ex-River[a]	0	0.0
Tidewater & Great Lakes	568	27.6
Truck	0	0.0
Subtotal	2,055	100.0
New York		
Rail	12,525	85.0
River & Ex-River	0	0.0
Tidewater & Great Lakes	375	2.5
Truck	1,842	12.5
Subtotal	14,742	100.0
Pennsylvania		
Rail	21,060	33.3
River & Ex-River	20,943	33.1
Tidewater & Great Lakes	263	0.4
Truck[b]	21,056	33.2
Subtotal	63,322	100.0
Middle Atlantic States		
Rail	6,986	52.8
River & Ex-River	0	0.0
Tidewater & Great Lakes	5,408	40.8
Truck	851	6.4
Subtotal	13,245	100.0
Total Northeast region		
Rail	42,058	45.0
River & Ex-River	20,943	22.4
Tidewater & Great Lakes	6,614	7.1
Truck	23,749	25.5
Total	93,364	100.0

[a] River & ex-river includes all shipments using a river barge somewhere between mine and consumer.

[b] Pennsylvania truck figure includes a small amount of coal shipped by tramway, conveyor belt, and private railroad.

mandated by the U.S. Department of Transportation, the Interstate Commerce Commission, and the USRA culminated in a final system plan issued by the USRA and submitted to Congress in August 1975.[4]

USRA's final system plan recommended that three railroad companies be responsible for all operations in the Northeast. The Chesapeake and Ohio (Chessie) system would take over some of the bankrupt lines of the Penn Central. The Norfolk and Western Railroad would expand into Pennsylvania and other Northeastern markets. ConRail would take over most of the bankrupt lines of the Penn Central, the Lehigh Valley, Central Railroad of New Jersey, and the Pennsylvania-Reading Seashore Lines, plus smaller portions of the Reading and Ann Arbor.[25] The basic objective of the USRA plan was to promote efficiency while retaining competitive service where demand was sufficient.

Recognizing that the rail system is vital to any national energy program aimed at increased coal production and use, the USRA recommended that all rail lines providing access to coal fields and not now in use should be retained in a "land bank" to ensure that coal resources not now in production could be transported by rail should they become economically recoverable.[25] Funding would be provided through subsidies under the Regional Rail Reorganization Act, or through an existing Federal agency. However, the plan does not include retention of rail service to former (and potential future) consumers of coal.

The nation's largest coal-carrying railroad, the Chessie system, is expanding its capacity. Orders have been placed for 16,000 new 100-ton-capacity hopper cars and 100 diesel electric locomotives at a total cost of $444 million.[23] By 1978 the Chessie system expects to be originating shipments of 110 million tons, 21% more than its 1974 level of 91 million tons.[23]

Improved rail system efficiency implies increased coal-carrying capability. By improving the physical condition of the track average speeds can be increased to allow better utilization of available rolling stock. Improvements in scheduling, signaling, and switching capability would also increase efficiency. For example, only about 14% of the life of an average freight car is spent on line haul.[5] The rest is spent in switching yards or at warehouses and industrial plant sidings. The complex regulatory structure for railroads may also contributes to such inefficiencies and merits substantial further attention.

One promising method of increasing the coal transport capacity of the rail system for major users is to use unit trains which run directly from the mine to the end-use consumer and carry only coal. They have an average capacity of $\sim$ 6000 tons, require only a four-man crew to operate, and circumvent the need for time-consuming and costly switching operations.[26] However, their operation requires that the consumer has rapid unloading and storage facilities and meets annual volume requirements.

Although unit trains are not currently in widespread use in the Northeast, their potential is readily illustrated. Assume a coal production source in southwestern Pennsylvania and a coal demand center on the New Jersey coast some 350 miles away. At an average train speed of 40 miles per hour, a round trip between mine and plant would take approximately one day, allowing an average of three hours for loading or unloading. At 6000 tons per trip, one train would supply enough coal to fuel an 800-MW electric power plant.

Another attribute of the unit train concept is that it does not depend on the financial viability of operating railroads. Unit trains are often purchased and operated by the utility company, which reimburses the railroad for use of the right-of-way. This approach has proved attractive in the Midwest, and the idea is gaining attention in the Northeast. For example, the Potomac Electric Power Company, serving Maryland and the District of Columbia, recently purchased two 80-car unit trains to deliver coal to their Chalk Point and Morgantown stations at a cost of $4.2 million. Both trains together will haul 1.2 million tons per year.[23]

In summary, the overriding need of the regional rail system, if it is not to become a bottleneck, is the rehabilitation of tracks and roadbeds to allow for future expansion. Hopper car and rolling stock shortages may be a short-term problem but are not expected to be a major constraint on increased use of coal. The Regional Rail Reorganization Act of 1973 provides $2 billion in financial assistance for rail rehabilitation. If coal utilization in the region does increase, additional revenues to railroads may help to ease their financial plight. However, government as well as private investment in the regional rail system is vital in the short term if an energy policy committed to the use of more coal is to be adopted.

C. Waterway Transportation

Water transportation by barge is the third largest mode of coal transport in the region, carrying 22% of coal shipments (Table 8). It is also the cheapest when both the mine and the end-use plant are located on or near a navigable body of water. The Ohio and Monongehela Rivers are now the main waterways used for coal transportation in the Northeast. At one time, however, coal was transported to several New York, New England, and Atlantic Coast utilities by shipping the coal by rail to major ports such as Baltimore and Hampton Roads, then transferring it to barges for shipment via intracoastal waterways.

Increased use of barges will be largely confined to plants located on waterways and having appropriate unloading facilities. The limited capacity of the waterway lock and dam systems could act as a constraint on any increase in coal barge traffic, which the Mitre Corporation has estimated will increase 55% nationwide by 1985 under a base-line demand scenario.[9] Thus, substantial federal investments in waterway facilities, as well as private investment in tugs and barges, may be necessary to meet new demands. Federal efforts to upgrade waterways have already been initiated.

D. Other Forms of Coal Transportation

1. Coal Slurry Pipelines. Coal slurry pipelines have been touted as an economical means of transporting large volumes of coal over long distances. Figure 13 presents a comparison of the economics of coal slurry pipelines with those of unit trains and extra-high-voltage AC transmission for a distance of 1000 miles. At this distance, a slurry pipeline is most economical for throughput volumes in excess of 8 million tons/year. However, the Northeast's coal comes largely from the northern and southern Appalachian regions, where most coal mining operations are small and dispersed and virtually no mines have enough capacity to economically support a pipeline. Since a similar situation exists at the end-use locations, establishment of a pipeline would require pooling of several producers and users, with pipe branchings at both production and utilization centers. The economics of such a situation are less favorable.

Important institutional barriers must also be considered. For example, coal slurry pipelines in the Northeast would require rights-of-way through densely populated areas, which would mean issuance of the right of eminent

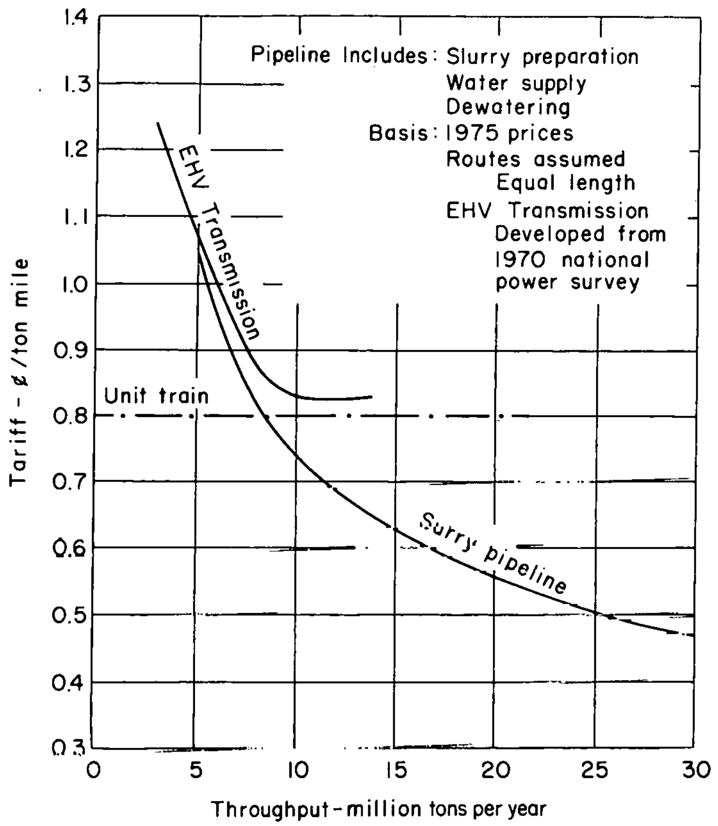

Figure 13. Coal transportation costs (for 1,000 mile transportation distance).[23]

domain to pipeline companies. This is not likely to be politically feasible in the Northeast. The use of existing railroad rights-of-way would require permission by rail companies to allow a low cost competitor to use its facilities. Thus, the conclusion here is that coal slurry pipelines are not likely to be built in the region in the foreseeable future.

2. High-Voltage Electrical Transmission. Long-distance ac high-voltage transmission is already being used to transport coal-derived energy to the Northeast. For example, several large mine-mouth power plants in western Pennsylvania have provided electricity for use in New York since about 1969. However, losses and instabilities associated with the transmission of electricity over long distances add to its cost. Figure 13 shows, for example, that EHV transmission is not competitive with unit trains at a distance of 1000 miles. Long-range dc

high-voltage transmission is designed to reduce transmission losses, but the technology for ac to dc conversion at high voltages is not available at present. Such an option may be feasible for the longer-term future.

Nontechnological barriers to long-range electrical transmission include jurisdictional and right-of-way considerations, as well as externalities such as air and water pollution and unsightly transmission lines. Those who benefit from remote mine-mouth generation are not the ones who have to bear the cost of these externalities, and at present no equitable method for transfer payments has been devised. Clearly, public sentiment will play an important role in deciding whether large mine-mouth power plants like those in Pennsylvania will be built to serve the needs of other states.

To summarize, coal slurry pipelines and long-distance electrical transmission have inherent problems, both technological and institutional, which will probably prevent their widespread use in the Northeast.

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IV. COAL UTILIZATION BY ELECTRIC UTILITIES

A. Introduction

In the near (1985) and longer-term (2000) future, the amount of coal that can be used to generate electricity in the Northeast will be affected by (1) the availability of coal supply and transport (already discussed); (2) environmental restrictions and technology; (3) the cost of alternative fuels; and (4) "institutional inertia."

This section will focus on environmental restrictions and control technology for using coal for electric power generation, which will in large part determine the cost of using coal versus alternative fuels. A comparative analysis of the costs of coal- and oil-fired generating capacity for future steam-electric power plants is given in Appendix E.

As used here, "institutional inertia" denotes the general reluctance of utilities to convert to coal, often because of the greater convenience and familiarity associated with the status quo. In addition, the risk and uncertainty involved in switching fuels in a changing economic and regulatory climate, coupled with disagreement on whether environmental control technology is sufficiently "available," militate against conversion to coal. On the other hand, political considerations regarding foreign leverage over American oil supplies weigh heavily in favor of domestic coal, even if it is uneconomical at current world energy prices. Many oil-consuming utilities in the Northeast are thus faced with a choice between maintaining the status quo, with the possibility of loss of supply, or risking a financial penalty for conversion to coal. In general, institutional inertia favors the former decision, although for some existing facilities no real option exists because of physical and technical constraints. Legislation has been proposed to require all new fossil-fired generating plants to burn coal after 1977 (U.S. Senate Bill S. 1777). However, until a more favorable regulatory, technological, and economic climate exists for oil-to-coal conversion, institutional inertia will remain an important constraint on increased coal utilization.

B. Environmental Restrictions and Control Technology

1. Regional Regulatory Policy. Increasingly stringent environmental regulations have contributed to the decline of coal use in the Northeast. The

Clean Air Act Amendments of 1970 require each state to submit a State Implementation Plan (SIP) to attain national primary and secondary ambient air quality standards (Table 9). The principal air pollutants associated with the burning of coal are particulate matter, sulfur oxides, and nitrogen oxides.[33] Since the technology for control of particulates is fairly well advanced, particulates are not generally considered to be a constraint on future coal use by electric utilities. Their control does, however, affect the cost of electrical generation. Similarly, nitrogen oxides can usually be controlled by proper boiler design and firing techniques. Although nitrogen oxide emissions from coal-fired plants are a problem in some cases (particularly in older plants), they are not considered a major constraint on future coal utilization.

Table 9

NATIONAL AMBIENT AIR QUALITY STANDARDS

Contaminant	Averaging Interval	Primary Standard $\mu g/m^3$	Primary Standard Approx. ppm (by vol)	Secondary Standard $\mu g/m^3$	Secondary Standard Approx. ppm (by vol)
Suspended Particulates	1 yr	75	-	60	-
	24 hr	260	-	150	-
Sulfur Dioxide	1 yr	80	0.03	-	-
	24 hr	365	0.14	-	-
	3 hr	-	-	1,300	0.5
Carbon Monoxide	8 hr	10,000	9.0	10,000	9.0
	1 hr	40,000	35.0	40,000	35.0
Photochemical Oxidant	1 hr	160	0.08	160	0.08
Nitrogen Dioxide	1 yr	100	0.05	100	0.05

Note: Concentrations specified for intervals other than one year are maxima not to be exceeded more than once per year for the interval stated. All concentrations relate to air at standard conditions of 25°C and 760 mm Hg. Annual average refers to arithmetic mean for gases and geometric mean for particulates.

Sulfur oxide emissions, on the other hand, are responsible for the most severe limitations[33] on conversion of electric utility plants from oil or gas to coal. SIP's for the Northeast region call for stringent limitations on stack-gas emission levels (see Table 10). For many states, existing regulations preclude the direct combustion of coal without a flue-gas desulfurization system, since little or no coal is available with sufficiently low sulfur content (e.g., <1.5% at 12,000 Btu/lb). Thus, for areas with an effective sulfur limitation of about 1.5% or less, some type of environmental control technology for sulfur as well as particulates is generally necessary to comply with state emission regulations.

2. Available Desulfurization Technology. Flue-gas desulfurization (FGD) systems, or scrubbers, represent the current technology for reducing emissions of sulfur oxides to the stringent levels prevalent in the Northeastern United States. Whether this technology is sufficiently reliable on a commercial scale is the subject of considerable national debate. Nonetheless, its success has been demonstrated in several operations around the country[30] and many utilities have shifted their concern to the economic rather than the technological aspects of such systems. In the present report it is therefore assumed that FGD systems will be technologically available for new plants beginning operation between 1977 and 1985. A critical question, however, is whether FGD is also a viable technology for the conversion to coal of plants currently operating on oil or natural gas.

For plants that can convert to coal, the ability to retrofit FGD systems depends on physical and technological factors and on the type of FGD process considered. The two process types considered here are throw-away sludge-generating systems and regenerative systems yielding a salable product. The most common throw-away systems are the lime/limestone scrubbers, and the most common regenerative type is the magnesium-oxide system. For the throw-away systems, land for sludge disposal must be available (∿12 million cu ft/yr for a 1000-MW plant), while the feasibility of a regenerative system is contingent on a market for the system's by-product (in most cases, sulfuric acid).[31] Regenerative systems also have higher initial capital costs than lime/limestone scrubbers.

The ability to retrofit also depends on the availability of space close to the boiler and stack for construction of the FGD unit.[32] For the densely populated coastal areas of the Northeast, space limitations for scrubber construction and sludge disposal poses a major constraint on the future use of this technology.

Economic factors especially affect the viability of retrofitting FGD systems. The first consideration is remaining plant lifetime; if a plant will

Table 10

NORTHEAST REGION FUEL SULFUR REGULATIONS[29]

State	Portion of State	Fuel Type	Sulfur Limitation (wt %)
Maine	Cumberland, Sagadahoe, Oxford, & York Counties	All	1.50
	Rest of state	All	2.50
New Hampshire	All	No. 6 residual	1.50
		Coal-existing boilers	1.68[a]
		Coal-new boilers	0.90[a]
Vermont	All	All	1.0
Rhode Island	All	All	1.0
Massachusetts	Boston area	Residual	0.52[b]
		Coal	0.34[a]
	Rest of state	Residual	1.02[b]
		Coal	0.66[a]
Connecticut	All	All	0.50
New York	All (variable regulations by Air Quality Control Region)	Residual	Varies between 0.3 and 2.0
		Coal	Varies between 0.3 and 2.2
New Jersey	Statewide except seven counties	Residual	0.3
		Coal	0.2[c]
	Atlantic, Cape May, Cumberland, Hunterdon, Ocean, Sussex, & Warren	Residual	1.0
Pennsylvania	Allegheny County, Beaver Valley & Monongahela Valley Air Basins, and Southeast Pa. Air Basin	All	Varies between 0.4 and 0.6, depending on boiler size[a]
	Remaining eight air basins	All	Varies between 1.1 and 1.9, depending on boiler size[a]
	Rest of state	All	2.5[a]
Maryland	All	Residual	0.5[c]
		Coal	1.0
Delaware	All	Residual	1.00[c]
	New Castle County	All	1.00
	Kent & Sussex Counties	All	2.00
District of Columbia	All	All	0.5

[a]For regulation expressed as pounds sulfur or SO_2 per million Btu, equivalent weight percent sulfur is calculated using 12,000 Btu/lb.

[b]Regulation expressed as pounds sulfur or SO_2 per million Btu equivalent weight percent sulfur is calculated by using 18,500 Btu/lb.

[c]Currently under consideration for revision.

remain in operation for only a few more years, FGD is not economically feasible. Although selecting a cutoff point is rather difficult, a common criterion, adopted here, is that plants less than 20 years old are candidates for FGD.

Vendor capacity, labor, engineering construction, availability, and lead-time requirements are other factors affecting potential FGD usage in the region. Figure 14 presents estimates of the national need for scrubber systems developed by the U.S. Environmental Protection Agency and assessments of vendor capacity by the Industrial Gas Cleaning Institute (IGCI) and the Sulfur Oxide Control Technology Assessment Panel (SOCTAP). The IGCI based their figures on a survey of vendors, who were asked to estimate unconstrained capacity, while SOCTAP based their estimate on an evaluation of vendors' ability to bring systems on-line smoothly, sell their systems, and expand their capacity.[33] Examination of Figure 14 suggests that vendor capacity will meet U.S. demand by 1978 or 1979. Because of institutional inertia and economic uncertainties, it is doubtful that any heavy marginal demand for FGD systems will develop in the Northeast before that time, so that vendor capacity should not be a major constraint on implementation of FGD systems in the region.

A final factor is the availability of capital to the electric utility sector for environmental control expenditures. Here, the use of tax-free bonds,

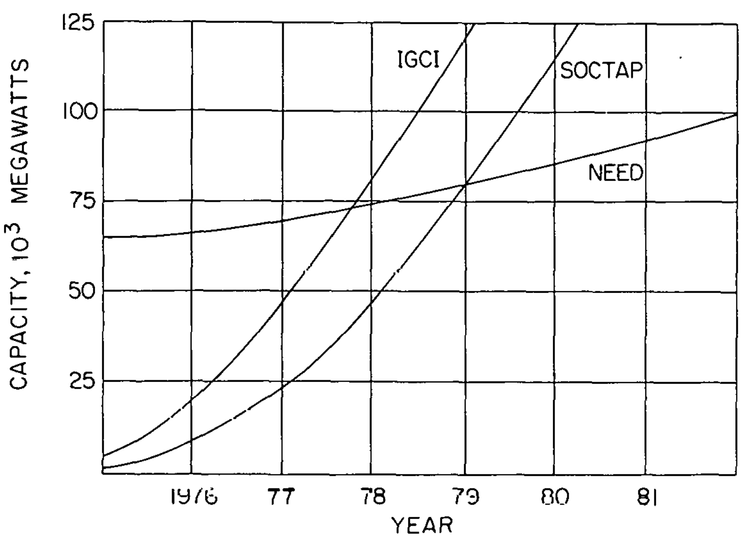

Figure 14. FGD vendor capacity estimates.[26]

government-insured loans, and rapid pass-through of environmental control costs are all areas of current public policy consideration. Utility financing must receive considerable additional attention if policy incentives for the use of coal in the region are to be developed.

In addition to FGD systems, the technologies currently available for the reduction of SO_2 emissions from coal-burning power plants include the precombustion removal of sulfur by mechanical coal cleaning. The increased cleaning of coal in preparation plants can decrease SO_2 emissions at a low cost compared with FGD systems. The principal drawback of coal-cleaning systems is that they cannot achieve the very low overall sulfur levels needed to comply with the more stringent state standards. Chemical coal cleaning, to remove additional (organic) sulfur from coal, is not yet commercially available but could become a viable option in future decades.

The use of tall stacks and intermittent control systems for meeting ambient air quality standards has also received considerable attention recently. Tall stacks disperse sulfur oxides at higher altitudes and thus decrease ground-level ambient SO_2 levels. Intermittent controls include load shifting and fuel switching during periods of adverse meteorological conditions. At present these control methods cannot be legally employed, since they do not meet SIP stack emission regulations. Also, current research by the U.S. Environmental Protection Agency and others indicates that sulfates formed in the atmosphere as a result of SO_2 emissions may be a more serious health problem than the SO_2 itself. Regulatory caution thus tends to preclude the use of tall stacks and intermittent control systems as an environmental control option for the region, at least until more conclusive research on the sulfate problem has been completed.

3. Present Use of Fossil Fuels and FGD Systems. Fuel use in the Northeast between 1961 and 1973 was discussed in Section I. The present situation of electric utilities with respect to fuel use, economics, and environmental effects is discussed in detail in Appendix C. A summary of these data for each of the four subregions of the Northeast is presented in Table 11. Comparison with Figure 3 shows little change in fuel mix between 1973 and 1974, although the prices of all fuels increased sharply as a result of the Arab oil embargo. Oil increased 98% between 1973 and 1974 to \$2.01/million Btu; coal also increased 98%, to \$0.91/ million Btu, although recently coal price levels have moderated. The trend to

Table 11

FOSSIL FUEL USE BY ELECTRIC UTILITIES IN THE NORTHEAST, 1974[a]

Location	Units Consumed	Energy Consumed (10^{12} Btu)	Total Fuel Cost (10^6 \$)	Average Price (\$/10^6 Btu)	Average Sulfur Content (%)
Mid-Atlantic States					
Coal (10^3 tons)	8,643	205.8	259.8	1.26	1.79
Oil (10^3 bbl)	67,067	408.4	828.4	2.03	0.82
Gas (10^6 ft^3)	13,669	14.0	13.0	0.93	-
Pennsylvania					
Coal	35,238	819.2	642.2	0.78	2.15
Oil	20,511	124.0	255.8	2.06	0.44
Gas	2,338	2.4	3.7	1.54	-
New York					
Coal	6,770	158.0	167.6	1.06	2.28
Oil	83,585	507.4	1,028.5	2.03	1.07
Gas	28,058	28.8	19.8	0.69	-
New England					
Coal	2,123	50.2	53.5	1.07	1.66
Oil	70,694	433.2	851.8	1.97	0.82
Gas	7,887	8.0	10.5	1.31	-
Regional Totals					
Coal	52,774	1,233.2	1,123.1	0.91	2.09
Oil	241,857	1,473.0	2,964.5	2.01	0.87
Gas	51,952	53.2	47.0	0.88	-

[a]From FPC Forms 1 and 67 for 1974.

increasing differences between coal and oil energy prices could provide an economic impetus for conversion from oil to coal in the region.

At present three FGD systems are operational in the Northeast: the Dickerson No. 3 unit of Potomac Electric Power in Maryland, the Phillips Plant of Duquesne Light Company in Pennsylvania, and the Mystic Station No. 6 of Boston Edison Company in Massachusetts. Another seven plants in the region are either constructing FGD systems or have plans to do so.[34] Table 12 summarizes all operating and planned regional FGD systems, their expected date of operation, and their recent status. The fact that eight utility companies have committed themselves to this technology is an indication of its growing acceptance as a means of emissions control in the Northeast.

C. Coal Demand Scenarios for 1985

In estimating the possible use of coal by regional electric utilities for 1985, two categories of plants are considered: existing fossil fuel capacity, and new plants that will begin operation before 1985. Demand scenarios for both cases are presented below, along with an analysis of some of the costs and benefits of converting fossil fuel-fired plants to coal.

1. Conversion of Existing Oil-Fired Capacity to Coal. Estimates of the potential for converting existing fossil fuel capacity to coal are derived from recent studies resulting from federal initiatives that consider environmental restrictions, coal supply, and transportation availability on a plant-by-plant basis in the region. The Energy Supply and Environmental Coordination Act of 1973 (ESECA) granted the FEA authority to prohibit oil burning by utility plants that met certain criteria and were designated for such prohibition by the EPA. Prior to issuing these orders, FEA identified those plants judged to be possible candidates for conversion and followed up with a series of studies and hearings to determine the possible costs and effects of conversion at specific sites. The initial cost and feasibility studies are still being refined and updated by PedCo Environmental Specialists, Inc., under contract to EPA.[35] In another EPA study, Foster Associates, Inc., is studying coal transportation and supply constraints, also on a plant-by-plant basis.[36] The work done by these contractors to date (August 1975) is used here to estimate the feasibility, economics, and environmental impacts of conversion from oil to coal in the Northeast region.

Table 12

STATUS OF FLUE-GAS DESULFURIZATION SYSTEMS IN THE NORTHEAST AS OF MAY 1975[34]

State	Company	Plant	Expected Start-up Date*	Current Status
MA	Boston Edison	Mystic No. 6	4/72	Shut down
	New England Power	Brayton Point No. 3	-	Under construction
PA	Duquesne Light	Phillips	7/73	Operational
		Elrama	9/75	Under construction
	Pennsylvania Power	Bruce Mansfield No. 1,2,3	10/75	Under construction
		Bruce Mansfield No. 4	4/79	Under construction
	Pennsylvania Electric	Homer City No. 3	-	Under construction
	Philadelphia Electric	Cromby	3/78	Planned
		Eddystone 1A	?/75	Under construction
		Eddystone 1B	3/78	Planned
		Eddystone No. 2	-	Under construction
MD	Potomac Electric Power	Dickerson No. 3	9/73	Operational
DE	Delmarva Power & Light	Indian River No. 4	-	Under construction

*Expected start-up dates are subject to delays.

Sixteen plants in the Northeast, all currently burning oil, were studied by the EPA contractors. Considering all the constraints involved, it is unlikely that any more generating plants could convert to coal before 1985, unless environmental restrictions are relaxed to allow coal-burning without flue-gas desulfurization.

Three conversion scenarios are developed in this report. The first considers plants for which no large expenditures would be needed to comply with environmental regulations for using coal. For these plants, conversion may be possible within a year.

The second scenario includes all plants in the first case plus those for which FGD technology is considered a feasible option. These plants should be able to convert to coal in the time required to plan and install the necessary environmental control equipment, but certainly by 1985.

The third case covers fossil-fueled plants that might be able to convert to coal if local emission standards were relaxed. Although this case is much more controversial, it should be considered in terms of estimating its possible economic and environmental effects, especially in light of the increased pressure to relax emission standards in certain areas.

a. Case 1. Conversion at "easily convertible" plants: Case 1 plants are those for which the FEA has issued orders of intent to prohibit oil burning (Table 13) on the grounds that they could be converted to coal within environmental regulations and without large expenditures for flue-gas desulfurization. As indicated in Table 13, the convertible capacity associated with this case is 3527 MW, representing N16% of 1974 oil-fired capacity in the region. The total estimated cost of conversion is N$69 million, with a resulting oil savings of 30 million bbl/yr.

The costs of conversion for each Case 1 plant reflect the FEA estimates made public when the intent orders were issued. However, both the cost estimates and the intent orders have been contested by several of the utilities involved. The FEA estimates in Table 13, therefore, are intended only as a guide to the likely magnitude of the direct cost to regional utilities for boiler and precipitator modifications, coal-handling facilities, and transportation facilities. Estimated savings from lower fuel costs are dealt with for all three conversion scenarios in Section IV.C.4.

b. Case 2. Conversion at "easy" plus "feasible" plants: The second conversion scenario includes plants that both FEA and EPA are considering as candidates for conversion in the longer run. These plants were not initially given intent orders because such orders were thought to have much greater environmental and economic impacts. This case includes updated assessments of conversion fea-

Table 13

FEA LIST OF POWER PLANTS WITH INTENT ORDERS FOR CONVERSION TO COAL,[37,38] CASE 1

(as of June 30, 1975)

Plant	State	Total Capacity (MW)	Convertible Capacity (MW)	Annual Additional Coal Required (10^3 tons)	Annual Fuel Oil Savings (10^3 bbl)	Estimated Total Cost of Conversion (10^3 \$)
Schiller	NH	179	100	176	668	2,424
Danskammer	NY	515	375	917	3,644	20,000
Albany	NY	400	400	1,041	3,876	9,000
England	NJ	476	300	836	3,396	3,240
Edgemoor	DE	836	357	833	3,319	12,980
Morgantown	MD	1,252	1,201	2,041	7,732	1,450
Crane	MD	400	400	976	3,806	
Riverside	MD	306	126	198	836	19,717[a]
Wagner	MD	1,043	268	594	2,488	
Totals		5,407	3,527	7,612	29,765	68,811

[a]Conversion costs for Crane, Riverside, and Wagner were considered together.

sibility and economics for several plants of Case 1, based on the results of the PedCo and Foster studies.[35,36] Thus, four of the plants in Case 1 (Albany, Edgemoor, Morgantown, and Crane) are allocated FGD systems in the longer-term "feasible" case. This additional requirement was based on the expected availability of low sulfur coal, as well as plant-specific economic and technological factors considered in the more recent studies for EPA.

Table 14 lists the candidate plants in this "feasible" category and the remaining "easily convertible" plants from Case 1. Shown are the convertible capacities, coal requirements, oil savings, environmental control options considered, and direct economic costs of conversion. Total convertible capacity is 5800 MW, or ∿26% of 1974 total oil-fired capacity. Total direct cost for con-

Table 14

"EASILY CONVERTED" PLUS "FEASIBLE" CATEGORY OF CANDIDATES FOR CONVERSION,[35,36,37] CASE 2

Plant	State	Total Capacity	Convertible Capacity	Annual Additional Coal Requirement (10^3 tons)	Annual Fuel Oil Savings (10^3 bbl)	Control Option Considered	Estimated Total Cost of Conversion (10^3 $)
Schiller	NH	179	100	176	668	New ESP's*	2,305
Danskammer	NY	515	515	1,200	4,757	ESP upgrade	27,000
Albany	NY	400	400	1,041	3,876	FGD	37,210
England	NJ	476	300	836	3,396	Low sulfur coal	3,240
Edgemoor	DE	836	357	833	3,319	FGD	32,930
Morgantown	MD	1,252	1,201	2,041	7,732	New ESP's	6,600
Crane	MD	400	400	976	3,806	FGD	35,620
Riverside	MD	306	306	406	1,713	New ESP's	18,680
Wagner	MD	1,043	268	594	2,488	New ESP's	12,610
Gould Street	MD	171	101	185	781	New ESP's	3,983
Salem Harbor	MA	805	227	549	3,027	FGD	26,000
Brayton Point	MA	1,600	965	2,357	10,873	FGD	68,610
Mt. Tom	MA	150	150	422	1,661	FGD	11,620
West Springfield	MA	223	202	455	1,472	FGD	8,630
Somerset	MA	527	194	500	1,986	FGD	21,000
South Street	RI	110	110	241	952	FGD	13,620
Total		8,993	5,796	12,812	52,507		329,658

*ESP = electrostatic precipitator.

version is estimated at $330 million, with an additional annual coal requirement of 13 million tons, and oil savings of 52 million bbl/yr.

c. Case 3. Conversion under relaxation of emission standards: The third scenario attempts to quantify the maximum effect on future regional coal utilization by relaxing state emission standards that may be more stringent than needed to meet existing national ambient air quality standards. The analytical techniques involved are currently being developed, most notably dispersion modeling techniques and data bases for multiple-source situations. Thus, the intent here is merely to estimate the possible magnitude of increases in coal use.

The plants in the Case 3 scenario are derived from various sources.[38-43] Information from these sources, as well as judgmental considerations, was used to select plants that could meet air quality standards by using coal of about 1.5% sulfur content, which should be available in sufficient quantities by 1985 to meet new demands (see Section I). A second criterion was that all plants must have had historical coal-burning capability. Finally, it was assumed that none of the conversion plants of Cases 1 and 2 would be effected by relaxation of emission standards.

Table 15 lists the plants meeting all three criteria. This report does not in any way recommend relaxation of emission standards for these plants; it merely looks at the possible regional impacts of such a scenario. Total and convertible plant capacities are given in Table 15. The direct capital costs of conversion are assumed to be negligible compared with the expenditures needed for conversion in Case 2. The only direct costs incurred in Case 3 are those for boiler modification and rehabilitation of old equipment. In this scenario, the total convertible capacity is 3105 MW, and the regional oil savings is 25 million bbl/yr.

Table 15 also shows the maximum effect of combining all three conversion scenarios. The total convertible capacity is ~8900 MW, or 40% of 1974 Northeastern oil-fired capacity. The total additional coal required by the region is 21 million ton/yr, yielding oil savings of about 77 million bbl/yr.

2. Cost-Benefit Approach to the Conversion Cases. Oil to coal conversion in the Northeast is desirable from an energy independence and/or balance-of-payments point of view in that it reduces reliance on imports of foreign oil. At current prices, it also results in reduced fuel costs. However, cap-

Table 15

COAL CONVERSION UNDER RELAXATION OF STATE EMISSION STANDARDS,[38-41,43] CASE 3

Plant	State	Total Capacity (MW)	Convertible Capacity (MW)	Annual Additional Coal Requirement (10^3 tons)	Annual Fuel Oil Savings (10^3 bbl)
Sayreville	NJ	347	248	692	2,264
Werner	NJ	116	60	161	479
Bergen	NJ	650	650	1,269	3,636
Burlington	NJ	455	193	395	1,220
Sewaren	NJ	850	119	209	821
Barrett	NY	375	175	439	1,226
Far Rockaway	NY	114	100	161	561
Port Jefferson	NY	467	350	842	3,033
Montville	CT	577	142[a]	380	1,450
Devon	CT	454	429[a]	950	3,284
Norwalk Harbor	CT	326	326[a]	944	3,216
Middletown	CT	837	183	494	1,940
Delaware City	DE	130	130	766	1,591
Subtotal		5,698	3,105	7,702	24,721
Case 2 Plants[b]		8,993	5,796	12,812	52,507
Total		14,691	8,901	20,514	77,228

[a]From ref. 42.

[b]From Table 16.

ital costs for conversion and indirect social costs from damage due to pollution tend to offset this reduction. In the absence of national political considerations, it is unclear whether the reduction in fuel costs resulting from oil-to-coal conversion is comparable with the increases in other costs (direct and indirect); i.e., whether conversion "makes sense" from an economic point of view. The following section attempts to place this issue in perspective for the three conversion cases and also for a "muddling through" case, which assumes no change in the future mix of utility fuels.

3. Methodolgy. The methodology used here is adapted from a recent study by the National Academy of Engineering (NAE) for the U.S. Senate.[44] The NAE format is helpful in determining whether a policy promoting the use of coal will be cost-effective to society for a given type or mix of technology. The specific problem considered is the environmental impact of SO_2 emissions from power plants.

To illustrate the NAE methodology, consider a hypothetical 1000-MW power plant with the capability to burn coal or oil. Given data on plant operating characteristics and fuel quality, the annual SO_2 emission can be easily calculated. Each pound of SO_2 emitted has a societal damage cost attached to it due to adverse effects on health, vegetation, materials, etc. If an accurate dollar value could be assigned to the marginal or incremental cost of air pollution damage caused by an additional pound of SO_2 entering the atmosphere, the total social cost of SO_2 emitted by this 1000-MW plant could be directly determined. Although the exact damage cost of such emissions is not known, estimated ranges of SO_2 damages are presented by the NAE (and others) for different power plant configurations.

For the hypothetical 1000-MW plant, if the rate of SO_2 emissions is known, the total societal (damage) cost is obtained by multiplying the mass of SO_2 emitted by the damage cost per pound of emission. As society judges each pound of SO_2 to be more damaging, the total damage cost of the plant emissions increases, as shown in Figure 15. The vertical axis indicates the annual sum of social, environmental control, and fuel costs associated with the generating plant for varying values of unit SO_2 damage cost (cents per pound of SO_2 emitted). The case of no environmental controls is represented by the line with the steepest slope. Note that if there were zero environmental damage cost, the intercept at $15 million/yr, representing the fuel cost, would be the total cost to society. At 30¢ damage/lb of SO_2, however, the total cost to society would be $50 million.

Suppose now that without environmental controls, the plant is in violation of the applicable emissions limitation. The options for compliance are to

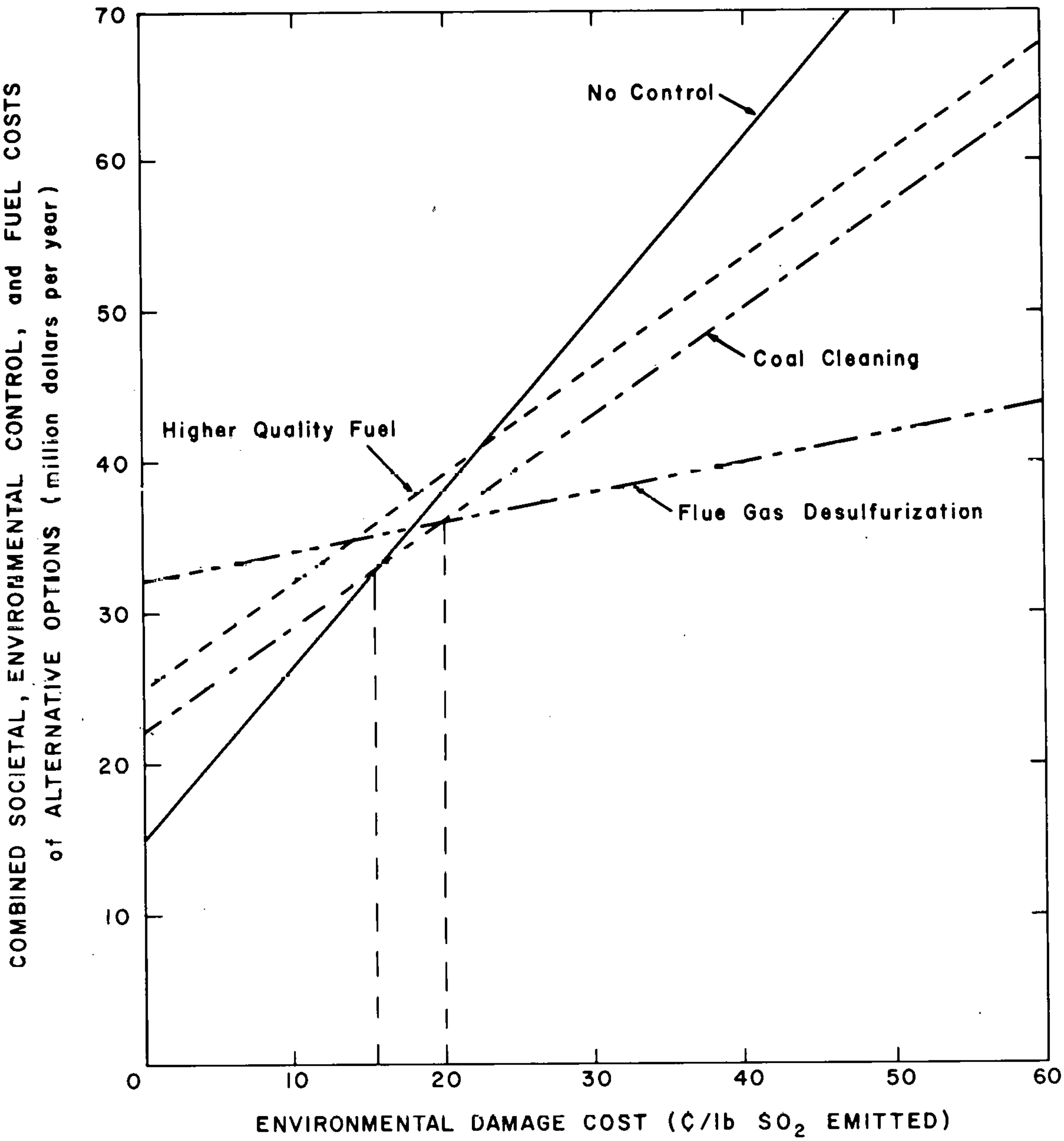

Figure 15. 1000 MW plant example, SO_2 social costs.

burn a higher quality fuel (oil or lower sulfur coal), institute precombustion coal-cleaning, or install an FGD system. The total economic cost to society of any one of these options is the capital plus operating cost of implementation (borne initially by the utility), plus the damage costs of emissions still remaining after the controls have been installed (borne indirectly by society).

This total cost is shown in Figure 15 for three illustrative control measures. The slope of each line is directly proportional to the resulting annual SO_2 emission, so that as plant emissions decrease, so does the environmental damage cost. Typically, however, the implementation (capital plus operating) costs tend to increase as emissions are reduced. Thus, the resulting total cost (to society) depends strongly on the economic damage to the environment. If this were well known, the socially optimal control option would be the one with the lowest overall cost at the known damage value. However, only a likely range of damages is known for SO_2. The NAE study suggests that this range is from 4¢/lb SO_2 emitted for a rural plant to \$1.00/lb for urban plant emission.[33] The most probable cost was estimated to be 10.5¢/lb SO_2 for a rural plant and 27.5¢/lb for an urban plant, assuming that all sulfur is emitted as SO_2 (Table 16).[44] For the hypothetical plant of Figure 15, this suggests stringent control (FGD system) would be appropriate in an urban area while no additional control might be optimal in a rural area.

However, severe limitations are imposed on this methodology by the present state of knowledge of SO_2 social costs and the relationship between sulfur emissions and atmospheric sulfate formation. Also, other pollutants released to the air, land, and aquatic environments are not taken into consideration here Finally, the distribution of environmental control costs among consumers and electric utility companies must also be considered in defining an "optimal" control strategy. Despite these limitations, the SO_2 social costing technique illustrated in Figure 15 does have some utility since it does not presuppose any single damage cost but rather points out the best options associated with different ranges of social cost.

It is instructive, then, to apply this technique to the three regional coal conversion scenarios developed earlier.

4. Oil-to-Coal Conversion Scenarios. Two new base-line cases are also considered here. The first represents the 1974 fuel mix and resulting SO_2 emissions. Because regional SO_2 emissions after 1974 did not in all cases meet the requirements of the various SIP's, the second scenario upgrades the current type of fuel to the quality (sulfur content) needed to attain compliance. To derive the added cost of this "compliance using current fuel mix" scenario, a regression analysis was performed of recent data on cost as a function of sulfur con-

Table 16

ESTIMATED DAMAGE COST (10^6 \$) OF SULFUR DIOXIDE EMISSIONS FROM RURAL AND URBAN PLANTS*[44]

(Representative calculation for plant emitting 10,000 kg of SO_x/hr, or 96.5×10^6 lb sulfur/yr)

REMOTE PLANT

Costs computed on the basis of 0.145 $\mu g/m^3$ increase in sulfate and 0.35 $\mu g/m^3$ increase in SO_2 concentrations in metropolitan areas with a population of 50 million

Health effects (computed at ambient level of 16 $\mu g/m^3$)	
25,600 cases of chronic respiratory disease at \$250	6.4
256,000 person-days of aggravated heart-lung disease symptoms at \$20	5.1
53,000 asthma attacks at \$10	0.5
6,200 cases of children's lower respiratory disease at \$75	0.5
14 premature deaths at \$30,000	0.4
Total health costs	12.9
Materials damage	
\$11.3 million per $\mu g/m^3$ of $SO_4 \times 0.145$	1.6
\$3.0 million per $\mu g/m^3$ of $SO_2 \times 0.35$	1.1
Aesthetics (\$0.034 x 96.5 x 10^6 lb)	3.3
Acid rain (\$0.015 x 96.5 x 10^6 lb)	1.4
Total emission costs	20.3

Emissions cost per pound of sulfur = 21¢

URBAN PLANT

Costs computed on the basis of 1.86 $\mu g/m^3$ increase in sulfate and 7.5 $\mu g/m^3$ increase in SO_2 concentrations in metropolitan areas of a population of 11.5 million

Health effects (computed at ambient level of 16 $\mu g/m^3$)	
75,500 cases of chronic respiratory disease at \$250	18.9
755,000 person-days of aggravated heart-lung disease symptoms at \$20	15.1
156,000 asthma attacks at \$10	1.6
18,400 cases of children's lower respiratory disease at \$75	1.4
42 premature deaths at \$30,000	1.3
Total health costs	38.3
Materials damage	
\$2.6 million per $\mu g/m^3$ of $SO_4 \times 1.86$	4.0
\$0.7 million per $\mu g/m^3$ of $SO_2 \times 7.5$	5.3
Aesthetics (\$0.034 x 96.5 x 10^6 lb)	3.3
Acid rain etc. (\$0.015 x 96.5 x 10^6 lb)	1.4
Total emissions costs	53.1

Emissions cost per pound of sulfur = 55¢

*Note that damage cost per pound of SO_2 is equivalent to one-half that per pound of sulfur.

tent for coal and oil purchased on a contract basis. The results, which were statistically significant, show that for each 0.1% decrease in sulfur content the price of coal increased by about 8¢ per million Btu, while the price of oil increased by about 5¢ per million Btu. The total cost of this compliance scenario was thus calculated by determining on a plant-by-plant basis (from the data of Appendix C) the reduction in coal sulfur content needed to meet emission regulations and the resulting added cost of fuel based on the regression analysis. Detailed calculations are shown in Appendix D.

For these two cases as well as the three cases of oil-to-coal conversions, the total annual fuel cost was calculated at average 1974 prices, except for the "feasible" conversion scenario, in which coal costs were based on price estimates made by Foster Associates for available coal.[36] Annual capital and operating costs of environmental control options were computed on a plant-by-plant basis as shown in Appendix D.

The regional summary of annual costs and emissions for all five cases is presented in Table 17. Both the annual fuel cost and annual conversion cost are indicated. The annual conversion cost is amortized based on a 15-year project lifetime at an interest rate of 9%.

It may be seen from Table 17 that compliance with existing SO_2 regulations (using the actual 1974 fuel mix) would limit annual emissions to 2.4×10^6 tons, compared with actual 1974 emissions of 2.9×10^6 tons. However, none of the conversion-to-coal scenarios uniformly attains SIP compliance since emissions from plants not converted were assumed to remain at their actual 1974 values. Additional calculations could be made based on the regression analysis data to show the cost-benefit of also purchasing higher quality (compliance) fuels at plants not converted. Note that the Case 1 scenario yields higher SO_2 emissions than the actual 1974 case. This is because allowable SO_2 emissions for coal are greater than for oil.

Figure 16 is similar to Figure 15, except that here emissions are aggregated to include all fossil fuel-fired plants in the Northeast region. The five lines represent the two cases of 1974 fuel mix (actual and upgraded), plus the three conversion cases. The intersection of each line with the vertical axis represents the annual conversion plus fuel costs of Table 17. In each case, the slope of the line is directly proportional to the magnitude of SO_2 emissions.

Table 17

REGIONAL COSTS AND SO_2 EMISSIONS

FOR SEVERAL CONVERSION SCENARIOS

Case	Annual Fuel Cost (10^6 \$)	Annual Conversion Cost (10^6 \$)	Conversion and Fuel Costs (10^6 \$)	Annual SO_2 Emissions (10^6 tons)
1974 Fuel mix (base case)	4135	0	4135	2.914
1974 fuel mix upgraded for SO_2 compliance	4638	0	4638	2.378
Conversion case 1	4026	8.5	4034	2.956[a]
Conversion case 2	3975	84.9	4060	2.865[a]
Conversion cases 1, 2, 3	3892	84.9	3977	2.873[a]

[a]Emissions from plants not converted are assumed to remain at actual 1974 values.

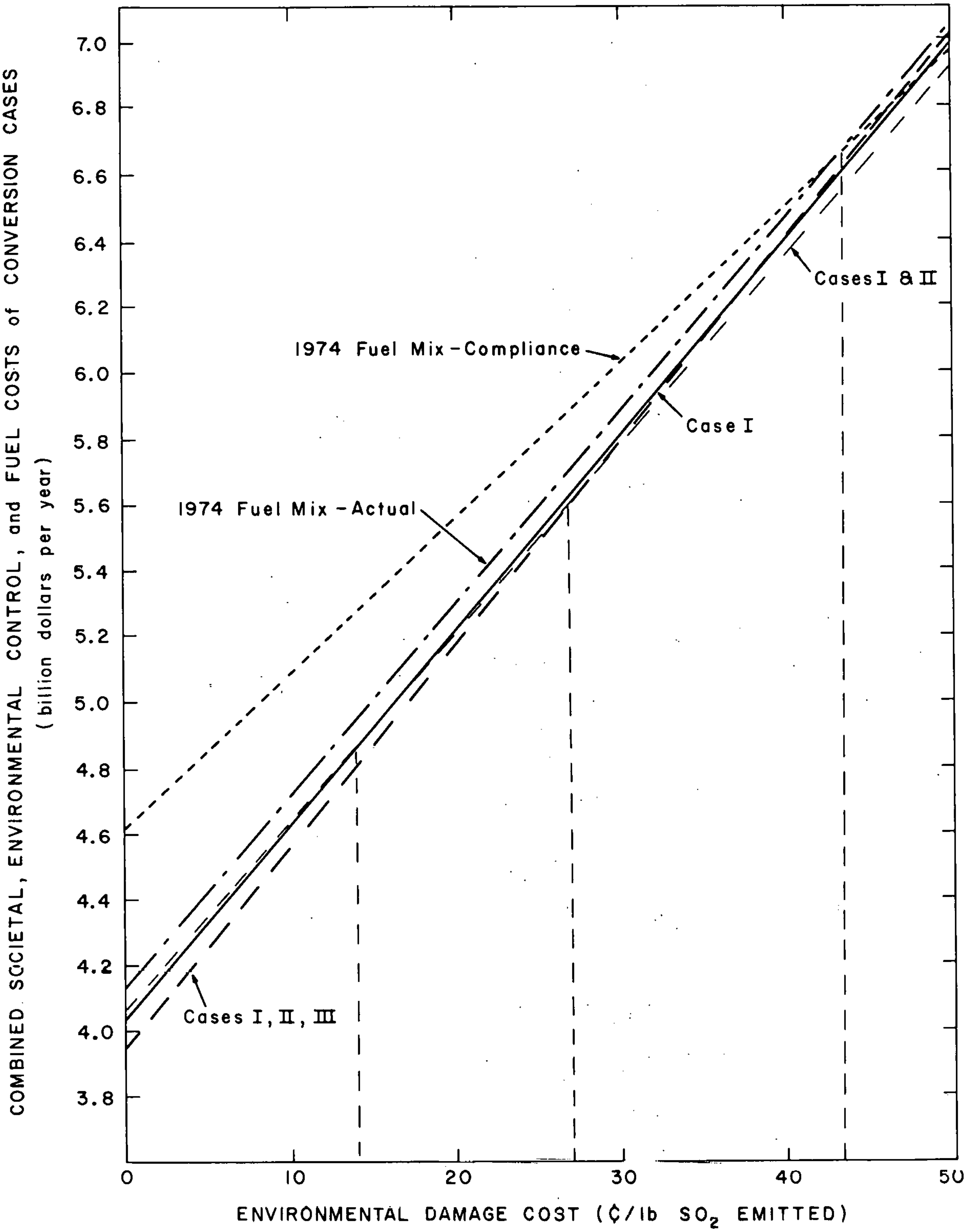

Figure 16. SO_2 social costs for Northeast region conversion cases.

Figure 16 indicates that up to an average environmental damage cost of 27¢/lb SO_2, the least-cost option is the conversion programs of Cases 1 and 2 plus standards relaxation (Case 3). Above 27¢/lb, conversion without relaxation is the optimal strategy. Note that any of the three conversion cases appears more attractive than the actual 1974 fuel mix up to an SO_2 damage cost of ~57¢/lb SO_2 emitted.

Given the earlier NAE estimates of probable SO_2 social costs (12¢/lb for a rural plant and 28¢/lb for an urban plant) a tentative conclusion is that conversion from oil to coal in the Northeast region may be cost-beneficial for the three conversion scenarios considered here. Caution must be exercised, however. Not only are marginal SO_2 damage costs uncertain, but aggregating emissions on a regional scale also ignores geographical variations, which could be significant. Nonetheless, the analysis suggests that some regional move toward coal utilization may be worthwhile on an overall economic basis, and data developed in this report could allow this analysis to be refined in greater geographic detail.

Other comparisons in Figure 16 are worth noting. For example, if relaxation of standards (Case 3) is deleted as being politically unacceptable, then Case 1 is the optimal strategy up to an environmental damage cost of 14¢/lb SO_2. Beyond that, Case 2 is the overall least-cost strategy. In comparing the two 1974 fuel mix cases, actual 1974 fuel quality yields a lower cost option if SO_2 damage cost is below 44¢/lb. This suggests that buying higher quality fuels to attain compliance produces benefits only in those instances where damage costs are thought to be relatively high.

Another important point is that each case in Figure 16 is very sensitive to changes in fuel price. Table 17 indicates that total annual fuel costs are very large relative to annual conversion costs. If oil and coal prices inflate at the same rate, then the relative desirability of the alternative options will not change. If oil prices remain steady while coal prices increase, a no-conversion scenario will look better. However, if oil prices inflate more rapidly than coal, a limited regional coal conversion program appears even more attractive.

5. <u>Potential for Coal Use at New Generating Plants</u>. Another source of additional demand for coal by 1985 will be coal use at new electric generating plants. Since the lead time for planning, designing, and constructing a new

plant is about ten years, significant changes in the utilities' presently planned mix of fossil and non-fossil plants for 1985 are unlikely. New plants at which coal use might be intensified are probably limited to planned additions of fossil-fuel capacity, and scenarios for coal use in new generating stations will be based on this assumption.

Scenarios for possible coal use in new fossil generating capacity (additions between 1975 and 1985) is bracketed by the following three cases: 1. all new fossil fuel capacity is coal (high case), 2. presently planned mix of fossil fuels is implemented (medium case), and 3. all new fossil capacity is oil (low case).

Estimates of total planned regional electrical generation by energy source for 1985, derived at BNL,[45] are shown in Table 18. Estimated generation by new fossil plants appears in Table 19. Assuming an average heat rate of 10,000 Btu/kWh, the required energy and fuel input quantities were calculated for each scenario (Table 20).

Table 18

ESTIMATED 1985 ELECTRICAL GENERATION IN THE NORTHEAST[45]

Source	Generation (10^9 kWh)	% of Total Generation
Nuclear steam	256.47	42
Coal-fired steam	167.53	27
Oil-fired steam	148.55	24
Hydro (conventional and pumped storage)	42.68	7
Pumping energy	-14.63	-2
Internal combustion and gas turbine	9.45	1.5
Combined cycle	1.30	0.5
Unclassified (fuel cell, etc.)	0.23	neg.
TOTAL	611.58	100

Table 19

ESTIMATED REGIONAL ADDITIONS OF OIL AND COAL GENERATION, 1975-1985

Fuel	Estimated 1985 Generation (10^6 kWh)	Actual 1974 Generation (10^6 kWh)	Estimated New Additions (10^6 kWh)	Estimated Additional Btu Requirement[a] (10^{12} Btu)
Coal	167,530	111,118	56,412	564.1
Oil	148,550	135,655	12,895	129.0
Total	316,080	246,773	69,307	693.1

[a]Based on average new plant heat rate of 10,000 Btu/kWh.

6. Summary of Scenarios for 1985. To characterize the range of possible electric utility coal demands for both existing and new capacity, five combinations of the conversion and new capacity scenarios are presented in Table 21. The lowest case is that of no conversion and no new coal-fired capacity additions. This is not a likely situation in view of recent and growing interest in the increased use of coal.

A more realistic case would be the conversion to coal at "easily" convertible existing plants, plus implementation of present plans for new coal-fired additions. A slightly higher medium coal use scenario would be the conversion to coal at "feasible" as well as "easy" existing plants, in addition to presently planned new capacity additions. This scenario, however, could be contingent on governmental or economic incentives for converting existing plants to coal.

A high coal use case is the combination of conversion at all "easy" and "feasible" plants, plus coal use at all new fossil fuel capacity additions. This scenario is similar to what would result from legislation currently under consideration by Congress. The highest coal use scenario adds relaxation of emission standards to the previous case. This extreme is also unlikely in view of the significant changes in environmental policy that would be required. How-

Table 20

SCENARIOS FOR FUEL USE AT

NEW FOSSIL PLANTS (1985)

Scenario	Additional Coal Requirement 10^{12} Btu[a]	Additional Coal Requirement 10^6 tons[b]	Additional Oil Requirement 10^{12} Btu[a]	Additional Oil Requirement 10^6 bbl[c]
High case - all new fossil fuel capacity is coal	693.1	29.7	0	0
Medium case - present utility plans for fossil fuel mix	564.1	24.1	129.0	21.2
Low case - all new capacity is oil	0	0	693.1	113.8

[a] From Table 19.

[b] Based on regional average 1974 coal heat value of 23.37 x 10^6 Btu/ton.

[c] Based on regional average 1974 oil heat value of 6.09 x 10^6 Btu/bbl.

Table 21

SUMMARY OF FIVE 1985

COAL USE SCENARIOS

Scenario	Required Oil Use		Required Coal Use	
	10^{12} Btu[a]	10^{6} bbl	10^{12} Btu[a]	10^{6} tons
A. No conversion and no new coal-fired generation	2166	355.6	1234	52.8
B. Conversion at easily convertible plants plus present plans for new capacity	1421	233.3	1975	84.5
C. Conversion at feasible plants plus present plans for new capacity	1283	210.6	2096	89.7
D. Conversion at all feasible plants plus all new fossil coal-fired capacity	1153	189.4	2227	95.3
E. Relaxation of emission standards - all new fossil coal-fired capacity	979	160.7	2419	103.5

[a]Based on the average heat values in Table 20.

ever, even for this highest coal use scenario, the coal supply estimates presented in Section II indicate that sufficient coal should be available to satisfy the 1985 demand for electrical power generation in the Northeast.

D. Coal Demand Scenarios for 2000

1. New Generating Capacity. New generating plants built between 1985 and 2000 will have much greater flexibility of fuel mix options, including advanced technologies permitting increased utilization of coal. For the purposes of the present study, three scenarios of the electric utility fuel mix in 2000 are developed with use of the BNL estimates of the medium regional electricity requirements in 1985 and 2000.[45] New capacity in these scenarios is treated only in terms of the net addition to regional generation between these two years; i.e., any plants retired between 1985 and 2000 are in the aggregate assumed to be replaced by plants using the same total quantity of coal as in 1985 (a conservative estimate for a high coal use case).

As a low bound, it is assumed that none of the additional net generation is coal-fired. Thus, coal use in 2000 remains at the 1985 level. Next, a medium case assumes that the fuel mix of new capacity added by 2000 will be the same as that now planned for 1985. A third (high use case scenario, reflecting the possibility of a nuclear moratorium and prohibition of the use of oil for new electric power plants, assumes that all net generation added between 1985 and 2000 will be coal fired.

The net increase in regional generation between 1985 and 2000 will be 655.22 million MWh as a medium case.[45] For 1985, 27% of total planned generation is estimated to be coal fired. Using these two figures, and assuming an average heat rate of 10,000 Btu/kWh for new plants, future coal energy requirements for new generation between 1985 and 2000 can be calculated for the three scenarios (Table 22).

2. Total Utility Coal Use. Three of the five scenarios for 1985 coal use in Table 21 are combined in Table 23 with the three scenarios for coal additions between 1985 and 2000 to indicate a possible range of coal usage by Northeast electric utilities in the year 2000. This range is between 85 and 384 million tons of coal, or $\sim$ 2.0 to 9.0 quad (10^{15} Btu) of energy. The wide range reflects the implications of relying on different mixes of coal, oil, and

Table 22

ESTIMATED COAL REQUIREMENTS FOR NET GENERATING ADDITIONS, 1985-2000

Scenario	Additional Coal Requirement[a] 10^{12} Btu	10^{6} tons
No new coal use after 1985	0	0
Same percentage coal use for added capacity as for nominal 1985 generation	1769	75.7
All net capacity added is coal fired	6552	280.3

[a]Based on 1974 average coal heat value of 23.37 x 10^{6} Btu/ton.

nuclear power for future electrical generation in the Northeast. Note that implementation of the highest coal use case could be constrained by available supply, according to the estimates in Section II.

E. Future Demand for Anthracite Coal

As noted in Section II, although anthracite coal will amount to only a small proportion of available total regional supplies, its production is capable of being expanded, provided that anthracite markets exist. A recent study by Berger Associates[21] suggests that potential markets do exist in the electric utility, industrial, commercial, and export sectors. Table 24 presents the Berger Associates' estimates[21] for possible future consumption of anthracite in these various markets. The 1991-2000 estimates are based on the ability of anthracite to compete with other fuels, as well as technical feasibility. They indicate that anthracite consumption in the year 2000 could amount to 17 million tons. Table 24 does not include possible markets associated with anthracite mining in the Narragansett Basin area of Massachusetts and Rhode Island.

Table 23

SCENARIOS FOR UTILITY COAL USAGE IN 2000

1985 Scenario[a]	2000 Scenario[b]	Annual Coal Requirement 10^6 tons	Annual Coal Requirement 10^{12} Btu
Conversion at "easy" plants, plus present plans for 1975-1985 new capacity	a. No new coal use after 1985	84.5	1975
	b. 1985 fuel mix in new plants	160.2	3744
	c. All net capacity added uses coal	364.8	8527
Conversion at "easy" and "feasible" plants plus present plans for 1975-1985 new capacity	a. No new coal usage	89.7	2096
	b. 1985 fuel mix in new plants	165.4	3865
	c. All net capacity added uses coal	370.0	8648
Relaxation of emission standards plus conversion at "easy" and "feasible" plants; all 1975-1985 new capacity is coal	a. No new coal usage	103.5	2419
	b. 1985 fuel mix in new plants	179.2	4188
	c. All net capacity added uses coal	383.8	8971

[a]Table 21, Scenarios B, C, and E.

[b]Table 22.

Table 24

POTENTIAL ANTHRACITE CONSUMPTION,[21] 1974-2000

Consuming Sector	Approximate 1974 Consumption (10^3 tons)	Potential Annual Consumption, 1981-1990 (10^3 tons) Minimum	Maximum	Potential Annual Consumption 1991-2000 (10^3 tons)
Electric utilities	1,380	1,380	4,430	11,000
Industry	2,006	3,006	3,973	4,125
Retail, commercial, institutional, home heating	2,000	1,500	2,000	1,500
Exports	780	250	1,000	5000
Total	6,166	6,136	11,403	17,125

V. SYNTHETIC FUELS FROM COAL

A. Present Status of Coal Conversion Programs

Conversion processes for producing synthetic gases and liquids from coal are receiving considerable attention as a means of utilizing abundant United States coal resources to help satisfy domestic demands for environmentally acceptable fuels. However, commercially available coal conversion processes are still limited primarily to pre-World War II technology, with some upgrading. Second-generation technologies offering more versatile and economic operation are at the laboratory-scale or pilot-plant stage and will not be commercially available before the early to mid-1980's in most instances.

Tables 25 to 27 list the coal conversion processes most likely to represent commercial-scale ventures in the latter part of this century. Low-Btu gas processes (producing gas with an energy content < 200 Btu/ft^3) are likely to be employed as a substitute boiler fuel for utility and industrial applications and as a working fluid in combined cycle processes for central station electrical generation. Low-Btu gas processes include the commercially available Lurgi and Koppers-Totzek processes, which are beginning to be used in the U.S. When coal is reacted with oxygen rather than air, such processes produce a medium-Btu gas with a heat value typically between 200 and 400 Btu/ft^3. Low and medium-Btu gas usually must be used near the site of conversion, since pipeline transport costs are uneconomical over long distances.

High-Btu gas (heat value > 900 Btu/ft^3) is produced by upgrading low or medium-Btu gas by a process known as methanation. This step has to date been demonstrated commercially only on a Lurgi gasifier in Scotland. Most high-Btu gas processes are at the pilot-plant stage and are not likely to be commercially available before the mid-1980's.[46] Pioneer projects in the U.S. using the Lurgi technology, however, may begin in the late 1970's to blend synthetic natural gas into existing pipeline supplies in the western parts of the U.S. Table 26 lists new second-generation processes under development.

The processes involved in the production of synthetic coal liquids, for the most part, are not yet beyond the pilot-plant state. The principal exception is the Fischer-Tropsch process, which has been used for several decades to produce gasoline from coal in Europe and Africa. Synthetic liquid production

Table 25

PROCESS FOR CONVERTING COAL TO LOW-Btu GAS[46]

Process	Agent
Atmospheric pressure fixed Bed	U.S. Bureau of Mines
Fixed-bed gasifier	General Electric Company
Entrained gasification	Combustion Engineering
Fluid-bed gasification	Westinghouse Electric Corp.
Two-stage slagging gasification	The Pittsburg & Midway Coal Mining Company
ATGAS	Applied Technology Corp.
Insitu gasification	U.S. Bureau of Mines
Elevated pressure entrained bed	The Pittsburg & Midway Coal Mining Company; Northern States Power; Foster Wheeler
Ignifluid	Fives-Gail Babcock, la Corneuve, France
Koppers-Totzek	Koppers, Inc.
Lurgi	Lurgi Mineralotechnik, Frankfort-am-Main, West Germany
Wellman-Galusha	Glen-Gery Corp.
Winkler	Pintsch Bamag, GmbH, West Germany
U-gas	IGT

in the U.S. is likely to lag behind the production of synthetic gases because of technological factors and high costs compared with current world prices of petroleum. Toward the latter part of this century, however, synthetic liquid fuels may play an increasingly important role in U.S. energy supplies by providing boiler fuels, refined products, or synthetic crude oil for use as a petroleum refinery feedstock. Table 27 lists several processes showing potential for commercialization.

Table 26

PROCESSES FOR CONVERTING COAL TO HIGH-Btu GAS[46]

Process	Agent
BI-GAS	Bituminous Coal Research, Inc. (BCR/OCR/AGA)
Consol synthetic gas (CSG) or CO_2 acceptor	Consolidation Coal Company, OCR/AGA
HYGAS	Institute of Gas Technology (IGT/OCR/AGA)
Synthane	U.S. Bureau of Mines
Hydrane	U.S. Bureau of Mines
Self-agglomerating gasification process	Battelle Memorial Institute (BMI/OCR)

Table 27

PROCESSES FOR CONVERTING COAL TO LIQUID[46]

Process	Agent
Solvent refined coal (SRC)	Pittsburg and Midway Coal Mining Co.
Solvent refined coal	Southern Services, Inc.
Synthoil	U.S. Bureau of Mines
H-Coal	Hydrocarbon Research Inc.
COED (char, oil, energy development)	FMC Corporation
Fischer-Tropsch	SASOL, - South Africa
Solvent digestion	National Coal Board

B. Current National Supply Estimates

1. Clouds in the Crystal Ball. Although the potential for a coal-based synthetic fuels industry in this country is large in terms of natural resources and technology, many additional factors introduce considerable uncertainty as to the levels of synthetic fuels production that will actually be realized during the next several decades. Some of these factors are listed in Table 28.

Table 28

CONSTRAINTS AFFECTING SYNTHETIC FUELS COMMERCIALIZATION LEVELS[47]

- Venture capital availability
- Air quality standards
- Resource availability
- Water availability
- Water quality standards
- Community impact
- Socio-economic factors
- Personnel, materials, and equipment
- Coal conversion technology
- Environmental control technology
- Institutional barriers

Economic considerations are perhaps the greatest inhibitor of synthetic fuel development in this country, since competing energy sources, as well as technologies for direct coal utilization, are in many cases more attractive than synthetic fuels processes at present. In addition, a host of technological, environmental, socio-economic, and political factors be resolved before synthetic fuel production forecasts can be sharpened. The approach taken here, therefore, is again to examine scenarios reflecting a range of possible futures for synthetic fuels from coal. As with the coal supply outlook, regional energy supplies to the Northeast are derived from national production level forecasts, reviewed below. The following paragraphs summarize the major assumptions for the synthetic fuels projections reviewed.

2. Synthetic Fuels Commercialization Program Levels. In his State of the Union Message of January 1975, President Ford called for accelerated development of U.S. energy technology and resources, including the target of producing the energy equivalent of one million bbl/day of synthetic fuels by 1985. An analysis and definition of a Synthetic Fuels Commercialization Program (SFCP) was the subject of a four-volume draft report issued by the Synfuels Interagency Task Force of the President's Energy Resources Council in June 1975. The SFCP study included processes for producing synthetic fuels

from shale oil and bio-mass as well as from coal, and examined three overall production (program) levels for the 1985 target date.[47] The lowest level, or "information program," was designed to produce the energy equivalent ∿ 350,000 bbl oil/day by 1985 of synthetic fuel. Of this, synthetic fuels from coal included 50,000 bbl/day of synthetic liquids, 40,000 bbl/day equivalent of high-Btu gas, and ∿ 125,000 bbl/day equivalent of low-Btu gas. The medium program, producing a total of one million bbl/day of synthetics fuels, included 100,000 bbl/day of coal liquids, 280,000 of high-Btu gas, and 250,000 of low-Btu gas. Finally, the "maximum program," representing an intense commercialization effort, was estimated to be capable of producing 1.7 million bbl/day of synthetic fuels, including 100,000 of coal liquids, 480,000 of high-Btu gas, and 525,000 of low Btu gas from coal.[47]

The three production levels examined in the SFCP effort may be taken as one estimate of high, medium and low scenarios for synthetic fuels availability in 1985. Medium production schedules are shown in Figure 17. The constraints on achieving any of the SFCP production levels include, to some extent, nearly all the items listed in Table 28. For all types of coal conversion processes, however, the most important constraint, regardless of the production target, appears to be the availability of venture capital.[47] Thus, one of the key tasks of the SFCP effort was to define and analyze alternative incentive plans, such as guaranteed government loans, which are considered essential if any significant commercialization of synthetic fuels is to come about within the next decade. Realistic forecasts of synthetic fuels production capability thus await administrative and Congressional action on an appropriate government incentive plan (if any). Even with this spur to U.S. commercialization, the environmental, social, institutional, and other constraints listed in Table 30 leave considerable uncertainty as to the rate of synthetic fuels commercialization in this country.

3. Stanford Research Institute Scenarios. Another useful set of estimates is derived from a Synfuels Interagency Task Force Report[16] which contains an analysis of future U.S. energy supply and demand by the Stanford Research Institute (SRI). This effort was part of the cost-benefit analysis of alternative production levels of synthetic fuels. It employed a computerized model developed by SRI which considered energy supply, demand, and price for all major forms of domestically produced and imported fuels (oil, gas, shale,

coal, nuclear, hydroelectric, and geothermal) over the period 1975-2025. Output included the price and quantities of primary energy resources and synthetic fuels products as a function of time. A more complete description of the model can be found in reference 16.

The SRI analysis included numerous cases demonstrating the sensitivity of synthetic fuels projections to uncertainty in selected variables, including import prices, availability of domestic oil and gas, cost of synthetic fuels, timing of synfuels commercialization, total U.S. energy demand, nuclear availability, cost of coal, rates of return, and hydrogen availability. Output of the analysis again included volume and market price trends of all energy sources in each scenario. In general, changes in demand had a much greater effect on imports than on synthetic fuels production, which indicates that the greatest impact of energy conservation would be a reduction in foreign supplies.

4. Project Independence Blueprint Scenarios. Another analysis of the potential for synthetic fuels from coal was conducted as part of the Project Independence Blueprint effort completed in late 1974.[46] The Synthetic Fuels Task Force Report reviewed the status of synthetic fuels technology, the economics of synthetic fuels processes, and the requirements and impacts of commercial synthetic fuels plant construction. On this basis, three production scenarios were formulated for low-Btu (utility) gas, high-Btu (pipeline) gas, and synthetic liquid fuels from coal. The scenarios corresponded to unconstrained production (high estimate) accelerated production (medium estimate), as business-as-usual production (low estimate).

The high (unrestricted) production estimate represents a crash program in which resources are expanded as quickly as possible and are fully devoted to the needs of a synthetic fuel plant construction program. The estimates of production levels were based solely on the judgment of the Task Force contributors, who caution that this scenario is believed to represent "a totally fictitious situation" in terms of its actual likelihood of implementation.

The accelerated development scenario, like the accelerated coal supply scenario, would require decisive governmental action designed to stimulate synthetic fuels commercialization. This would include financial incentives (such as price support, government guaranteed loans, and tax incentives), water allocation priorities, extension of pollution control schedules, one-stop permit provisions, continuation of oil depletion allowance, modification of public lands leasing practices, and possible other proposals representing substantial modification of the government's pre-1974 position.

The business-as-usual scenario reflected no basic changes in the government's position, i.e., no loan guarantees or other incentive program, no equipment priorities, and no enactment of "energy crisis" legislative proposals. It was assumed, however, that long-term research and development programs would be supported on an accelerated basis, with additional or parallel R&D as required. The business-as-usual projection was presented by the Project Independence Task Force as a "pessimistic" production value, originally derived from the minimum rate of buildup that could be foreseen on the basis of economics current at the time of the study. This included comparisons with estimates of the initial growth of similar industries to lend some historical perspective. No explicit considerations of supply versus price, however, were employed in any of the Project Independence synthetic fuels production scenarios.

5. Energy Research and Development Administration Scenarios. Another source of estimates regarding future production of synthetic fuels from coal is ERDA's 1975 plan for energy research, development, and demonstration.[13] The ERDA plan presents six scenarios of U.S. energy supply and demand for 1985 and 2000 using the Reference Energy System Model developed by Brookhaven National Laboratory. This model simulates the complete fuel cycle from resource extraction through end use for all significant categories of energy supply and demand.[48] Unlike the SRI model, which computes the volumes and market clearing prices of competing fuels at three-year intervals on the basis of marginal cost and regional supply/demand variations, the BNL model employs a linear programming technique to optimize the entire national energy system at a given time, subject to national constraints on end-use energy demands, resource supplies, and technological capabilities (cost and efficiency).

In three scenarios, no production of synthetic fuels from coal is considered. A non-zero supply first occurs in Scenario II, which calls for increasing supplies of liquids and gases with synthetic fuels from coal and shale. This assumes an accelerated commercial development program with federally cost-shared pilot and demonstration plants in operation by 1980-1981. This scenario places the largest demand on U.S. coal supply, which must double by 1985 and again by 2000. Growth in electric power production is based primarily on nuclear energy to allow new coal production to be used for synthetics. Note that the predicted supply of synthetic gas and liquid in this case is the same as in Scenario IV, which examines the case of limited availability of nuclear power. This is because the scenario arbitrarily directs coal toward synthetics rather than electricity production, with solar, geothermal, and fusion sources combining with industrial end-use conservation to compensate for the postulated post-1985 loss of nuclear energy growth.[13] Scenario V yields the same estimates for synthetic gas and liquids as Scenarios II and IV. Here all major energy technologies are simultaneously commercialized in an attempt to meet U.S. energy requirements solely with domestic supplies and reduce or eliminate energy imports. As with other estimates of future synthetic fuels production, the ERDA scenarios indicate relatively small supplies of coal synthetics in 1985, but more appreciable quantities by the year 2000.

6. Other Synthetic Fuel Production Estimates. The references cited above represent the most recent published estimates of national synthetic fuel production levels for the next 25 years. To a large extent, they incorporate refinements in earlier estimates made by various organizations, including the National Academy of Engineering, U.S. Federal Power Commission, Institute of Gas Technology, National Petroleum Council, and others. Most do not extend to the year 2000 but tend to lie within the range encompassed by the more recent forecasts for 1985.

C. Scenarios for U.S. Synthetuc Fuel Production

Figures 17 to 19 compare various current estimates of high-Btu gas, low-Btu gas, and synthetic crude oil from coal for the years 1985 and 2000. The appreciable variation even among very recent estimates underscores the uncertainty regarding the future of synthetic fuels from coal over the next 25 years. These estimates can be used, however, to establish a supply range reflecting low, medium, and high estimates of national production, which can in turn be useful in estimating the potential impact of synthetic fuels on the Northeast regional energy situation over the remainder of this century.

Table 29 presents three such scenarios. For 1985, the medium estimate of total coal gas production is 1.1 quadrillion Btu/yr (quads), of which a little more than half is high-Btu substitute natural gas (SNG). Synthetic liquids and coal gas production have increased 5- to 10-fold. Liquids are estimated to contribute between 0.4 and 10.0 quads, while synthetic gases from coal contribute from 4.8 to 16.0 quads, of which ∿ 60% is high-Btu gas.

Table 29

SUPPLY SCENARIOS FOR U. S. SYNTHETIC FUELS FROM COAL IN 1985 AND 2000

(10^{15} Btu/yr)

Scenario	1985 High-Btu Gas	1985 Low-Btu Gas	1985 Liquids	2000 High-Btu Gas	2000 Low-Btu Gas	2000 Liquids
I Low supply	----------negligible--------			3.0	1.8	0.4
II Medium supply	0.6	0.5	0.2	6.0	4.0	4.0
III High supply	2.0	1.5	1.5	10.0	6.0	10.0

D. Synthetic Fuels Impact on Northeast Energy Supplies

Within the Northeast region only Pennsylvania with its large reserves of bituminous coal is a plausible site for development of a coal conversion industry. For the most part, the contribution of coal synthetics to the Northeast will come indirectly through augmented national supplies of crude oil and natural gas and from production of electricity and process heat through combustion of coal converted to low or medium-Btu gas. Synthetic liquids and natural gas supplied to the Northeast could conceivably be produced at coal conversion facilities in many parts of the country, since the distribution system for these two products is virtually nationwide. However, regional variations in the supply, demand, and price of alternative energy forms will significantly affect the types and locations of synthetic fuels plants and products.

1. Foster Associates Analysis of Regional Markets. A recent study made by Foster Associates for ERDA addressed the question of regional markets for synthetic fuels in 1980 and 1985.[52] Results indicated a sizable market potential for coal synthetics in the eastern United States. Coal conversion was assumed to take place in four regions of the country, including two eastern regions (Appalachia and East Central) and two western regions (North Great

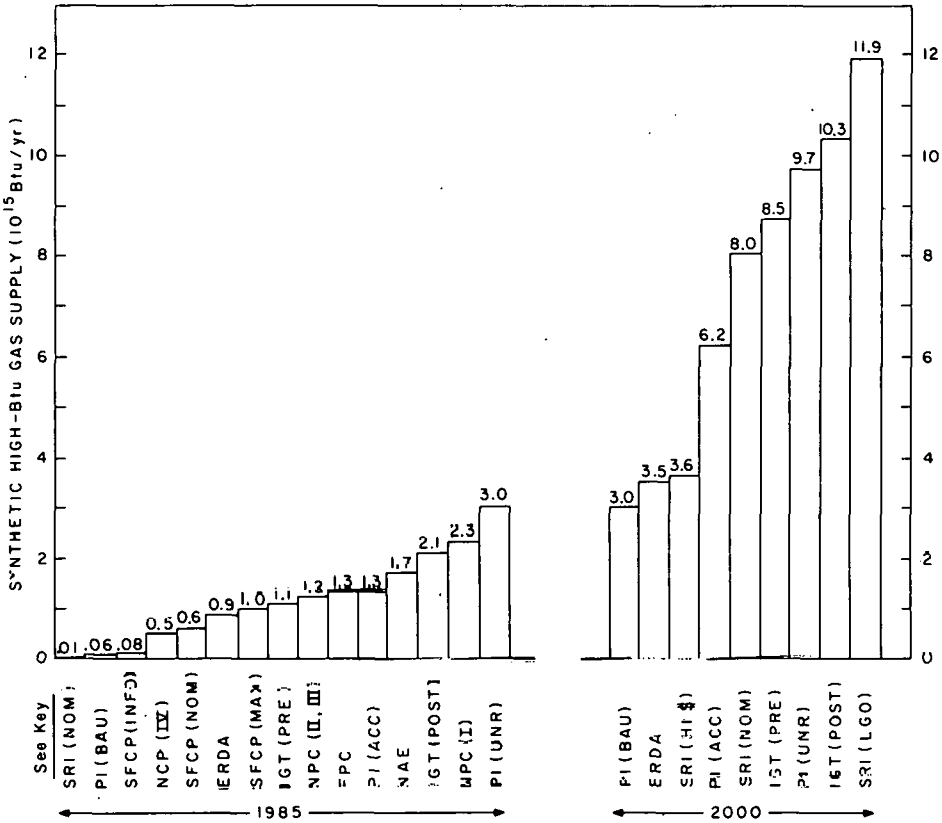

Figure 17. Comparisons of supply estimates for high-Btu gas from coal in 1985 and 2000.

KEY TO SCENARIO ABBREVIATIONS IN FIGURES 17-19

ERDA	Energy Research and Development Administration Scenarios II,IV,V
FPC	Federal Power Commission National Gas Survey
IGT (PRE)	Institute of Gas Technology Pre-1973 Scenario
IGT (POST)	Post-1973 Scenario
NAE	National Academy of Engineering
NPC (I)	National Petroleum Council Case I
NPC (II,III)	Cases II,III
NPC (IV)	Case IV
PI (ACC)	Project Independence Accelerated Production
PI (BAU)	Business as Usual
PI (UNR)	Unrestricted Production
SFCP (INFO)	Synthetic Fuels Commercialization Program Information Option
SFCP (NOM)	"Nominal" Program Option
SFCP (MAX)	Maximum Program Option
SRI (NOM)	Stanford Research Institute Model "Nominal" Scenario
SRI (5YR)	5-Year Delay in Synfuels
SRI (LGO)	Low Domestic Gas and Oil Availability
SRI (LGOI)	Low Gas and Oil With High Import Prices
SRI (HI$)	High Fuels Price

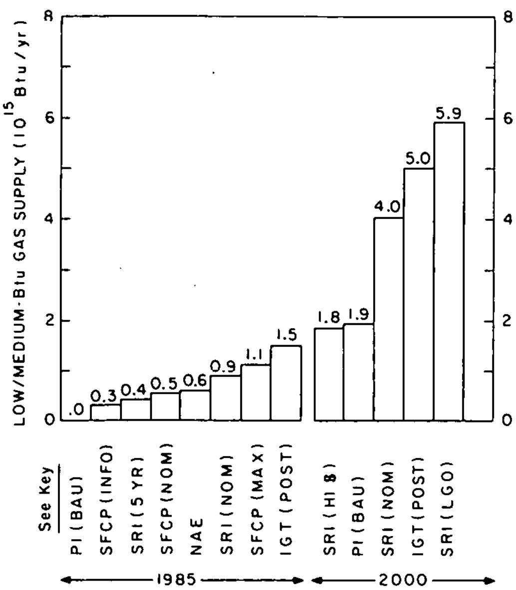

Figure 18. Comparisons of supply estimates for low and medium Btu gas in 1985 and 2000.

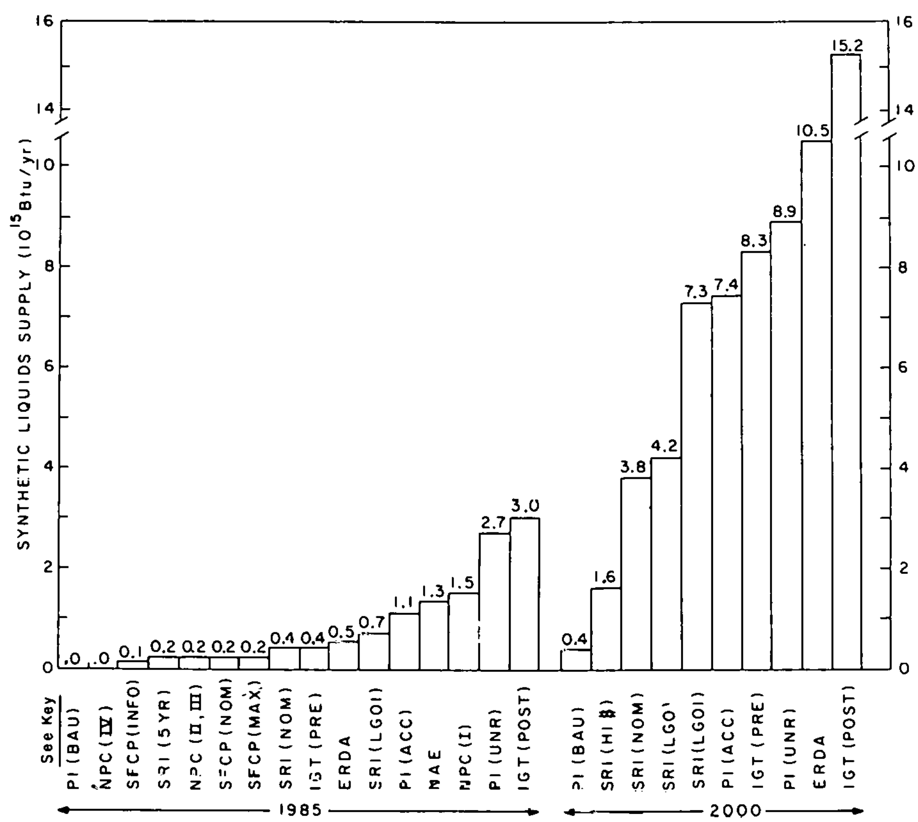

Figure 19. Comparisons of supply estimates for synthetic liquids from coal in 1985 and 2000.

Plains and Four Corners). High-Btu gas could enter pipelines already traversing these regions, while coal liquids could potentially be marketed directly as fuels, refined at the coal conversion site, or delivered as crude oil feedstock to one of six key refining centers in the United States. Low-Btu gas could be used only locally by electric utilities and industrial consumers.

Prospective regional markets for synthetic natural gas, low-Btu gas, and synthetic liquids were characterized in this analysis in terms of projected deficits in five Petroleum Administration for Defense (PAD) districts encompassing the contiguous 48 states. The Northeast region is part of PAD I, which extends along the entire eastern seaboard. Table 30 shows the projected regional deficits of natural gas and crude oil for 1985 based on supply, demand, and price considerations, as well as the cost and capacity of available transportation to 45 cities representing key metropolitan areas within the five PAD districts. These figures are used to calculate "net-back" and break-even costs of various synthetic fuel products produced at each of the four regional coal conversion areas. The eastern (East Central and Appalachia) coal regions were found to be the most attractive sites for producing synthetic crude oil for refineries, and low-Btu gas for utility and industrial use. Western coal regions appeared more attractive for synthetic natural gas production, although sizable potential SNG markets also existed in eastern areas. While volume of coal synthetics that would be produced regionally, the economic analysis presented indicated that development of coal synthetics in eastern regions serving the Northeast may indeed be a viable option for the near future.

2. Synthetic Fuels Commercialization Program Scenarios. Regional energy considerations were also incorporated into the SFCP scenario analysis employing the Stanford Research Institute model discussed earlier. Here, the U.S., was divided into eight demand regions, two of them encompassing all the Northeast region as defined in the present study except for Maryland, Delaware, and the District of Columbia. End-use energy demands were established for each region and were satisfied by resources distributed geographically, as shown in Figure 20. Sources and quantities of supply were assumed to be dictated only by economic considerations established by the availability of resources, technology, transportation, etc. Thus, demand for natural gas in the Northeast might be met by synthetic gas produced in Appalachia, or by domestic gas produced in the

Table 30

FOSTER ASSOCIATES ESTIMATES OF 1985 REGIONAL DEFICITS OF PETROLEUM PRODUCTS AND NATURAL GAS[52]

Region	Petroleum Deficit[a] (bbl/day)	Natural Gas Deficit[b] (10^{12} Btu/yr)
PAD I	6291	2782-3991
PAD II	1376	4285-6410
PAD III	(3934)[c]	3401-6151
PAD IV	152	217- 458
PAD V	776	1155-1739

[a]Before interdistrict shipments.

[b]Total market. Priority markets are substantially smaller for all regions.

[c]Indicates surplus.

Gulf Coast. Extra regional factors such as the development of a synthetic fuels industry in the West still indirectly affect the Northeast, since they act to relieve what would otherwise be a stronger competing demand for available domestic resources.

In the absence of political constraints on interregional shipments of synthetic fuels, therefore, synthetic fuels from coal contribute to the energy supplies of the Northeast by augmenting other national supplies of gaseous and liquid fuels, and/or by displacing foreign imports according to market forces. The resulting distribution of available supplies, in the light of established end-use energy demands, was calculated from the SRI model for each of the eight regional demand sectors.

Tables 31 and 32 show such projections for gaseous fuels, liquid fuels, coal, and electricity in 1986 and 2001 for the SRI "nominal case" situation. Included are all the states in the Northeast region except Delaware, Maryland, and the District of Columbia. Low-Btu gas and coal use in these tables refers only to industrial and commercial utilization; it does not include the additional use

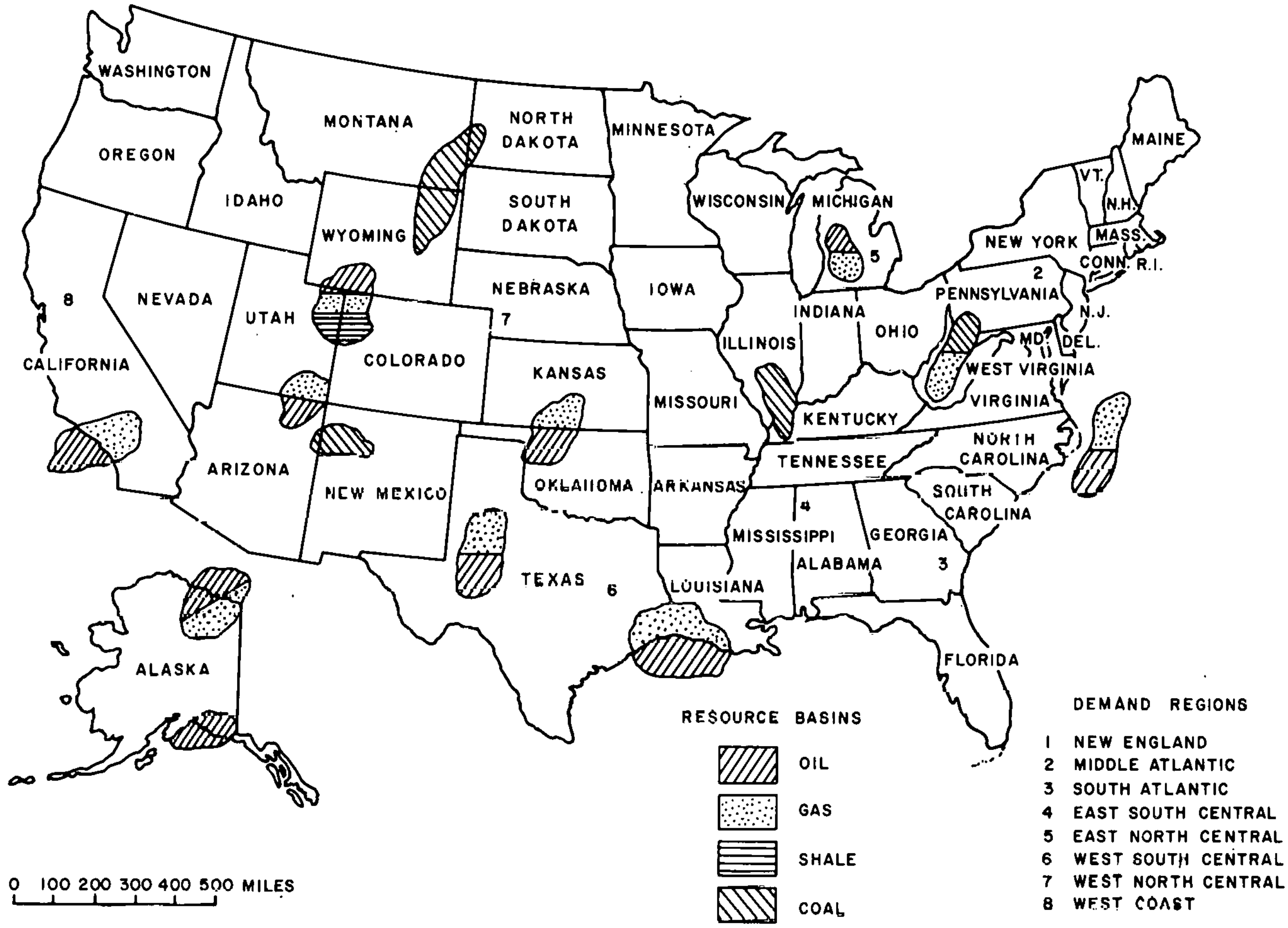

Figure 20. U.S. energy model resource locations and demand regions.[51]

of coal (either directly or in combined cycles using low-Btu gas) for electrical power generation.

F. Scenarios for 1985 and 2000

Tables 31 and 32 indicate that New England, New York, New Jersey, and Pennsylvania together are expected to receive about 15% of future U.S. natural and low-Btu gas supplies, and 25% of the total petroleum products supply, according to the SRI model. Additional supplies to Delaware, Maryland, and the District of Columbia would raise these figures for the entire Northeast region

Table 31

1986 REGIONAL DISTRIBUTION OF ENERGY PRODUCTS, SRI "NOMINAL" CASE[53]

(10^{15} Btu/yr)

Energy Form	New England	N.Y., N.J., Pa.	Two-Region Total	Percent of U.S. Total
GASEOUS FUELS				
High-Btu	0.494	2.933	3.427	14.5
Low-Btu and H_2	0.026	0.130	0.156	15.1
Total	0.520	3.063	3.583	14.6
LIQUID FUELS				
Low-S Residual	0.469	1.209		
Gasoline	0.741	2.864		
Distillate	0.476	2.186		
Methyl	0.029	0.078		
Solvent Refincd Coal	0.014	0.055		
Total	1.729	6.392	8.121	25.1
COAL	0.051	0.547	0.598	14.8
ELECTRICITY				
Baseload	0.036	1.123		
Inter & Peak	0.115	0.430		
Total	0.478	1.553	2.031[a]	19.1
TOTAL END-USE ENERGY	2.778	11.555	14.333	20.0

[a]Approximately 25% from oil and gas, 25% from coal, and 50% nuclear.

Table 32

2001 REGIONAL DISTRIBUTION OF ENERGY PRODUCTS,

SRI "NOMINAL" CASE[53]

(10^{15} Btu/yr)

Energy Form	New England	N.Y., N.J., Pa.	Two-Region Total	Percent of U.S. Total
GASEOUS FUELS				
High-Btu	0.517	3.158	3.675	14.7
Low-Btu and H_2	0.096	0.481	0.577	13.8
Total	0.613	3.639	4.252	14.5
LIQUID FUELS				
Low-S Residual	0.475	1.413		
Gasoline	0.863	4.103		
Distillate	0.832	2.367		
Methyl	0.052	0.141		
Solvent Refined Coal	0.061	0.248		
Total	2.283	8.272	10.555	23.6
COAL	0.129	0.884	1.013	13.5
ELECTRICITY				
Baseload	0.567	1.803		
Inter and Peak	0.176	0.593		
Total	0.745	2.396	3.140[a]	19.5
TOTAL END USE ENERGY	3.770	15.191	10.961	19.4

[a] Approximately 10% from oil and gas, 20% from coal, and 70% nuclear.

to about 16% for gas and 28% for liquids, based on the current distribution of fuels within the region.[54] Some sense of the "effective" contribution of coal synthetics to the regional energy supply can be obtained by applying these percentages (which the SRI model indicates are relatively insensitive to changes in the availability of specific fuel sources for a wide range of cases studied) to the total U.S. supply of synthetic fuels. Table 33 shows the resulting range of "effective" supplies, corresponding to the range of national supply scenarios in Table 29.

Table 33

EFFECTIVE CONTRIBUTION OF SYNTHETIC FUELS TO NORTHEAST REGIONAL ENERGY SUPPLIES IN 1985 AND 2000[a]

(10^{15} Btu/yr)

		1985			2000		
	Scenario	High-Btu Gas	Low-Btu Gas	Liquids	High-Btu Gas	Low-Btu Gas	Liquids
I	Low supply	0.0	0.0	0.0	0.5	0.3	0.1
II	Medium supply	0.1	0.1	0.05	1.0	0.6	1.1
III	High supply	0.3	0.2	0.4	1.6	1.0	2.8

[a]Assumes that "effective" regional fraction of U.S. total (Table 32) is 16% for gases and 28% for liquids.

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APPENDIX A

NATIONAL COAL SUPPLY ESTIMATES

1. District Production Levels

Appendix A presents the detailed data and calculations from which domestically available U.S. Bureau of Mines (USBM) district-by-district coal supply was estimated for 1985 and 2000. As stated in the text, the two Project Independence (PI) estimates were given on a district basis through 1990. For the business-as-usual (BAU) case it was assumed in the present study that each district's growth as a fraction of national growth would be the same during the 1990-2000 period as its 1985-1990 growth as given by PI.

For the PI accelerated scenario, a 3% growth rate was assumed for total U.S. production between 1985 and 2000. This was apportioned among districts in the same ratios as PI district-to-national growth in the 1980-1985 accelerated case.

For the low 3% growth case, no district production estimates were available. It was assumed that district growth rates would be similar to those for the PI-BAU case. The year 1973 was used as a base for district production, and increases in each district for the low case were calculated by finding the fractional percentage of 1973-1985 BAU increases for each district. For example, district 1 fractional production for the BAU case was calculated from the following formula:

$$f_1 = \frac{\Delta \text{ BAU production in district 1 (1973-1985)}}{\Delta \text{ BAU national production (1973-1985)}}$$

The 1985 production for each district under the low 3% growth case was then calculated simply as

$$\begin{aligned} &\text{1985 Production in district d} \\ &= f_d \times \text{1985 national production in low growth case} \end{aligned}$$

For 2000, a similar methodology was used, except that district production was allocated on the basis of PI growth rates for 1985-1990. Table A-1 summarizes district production estimates for 1985 and 2000.

Table A-1

DISTRICT PRODUCTION ESTIMATES FOR 1985 AND 2000

(10^3 tons)

District	No.	1985 Low[a]	1985 Medium[b]	1985 High[c]	2000 Low	2000 Medium	2000 High
Northern Appalachia	1	53,500	59,400	113,300	66,640	88,800	179,020
	2	43,800	51,900	101,200	59,840	78,300	141,420
	3&6	53,200	61,100	113,300	61,540	88,250	165,200
	4	59,900	70,950	131,400	87,720	109,650	198,300
Southern Appalachia	7	42,500	52,350	99,200	59,160	78,450	150,740
	8	224,100	279,450	514,300	333,540	426,600	786,470
	13	32,500	42,350	77,200	38,760	59,450	110,880
Midwest	9	67,800	78,750	146,300	98,600	122,250	218,870
	10	76,000	87,650	165,400	110,840	136,550	249,730
	11	33,100	39,500	70,200	47,600	60,500	107,030
Near West	12	1,200	1,650	3,000	2,040	2,550	4,820
	14	1,200	1,650	3,000	2,040	2,550	4,820
	15	39,900	60,500	110,800	95,200	102,500	166,160
Far West	16-23	145,300	212,800	414,400	296,480	343,600	730,540
Total		874,000[d]	1,100,000	2,063,000	1,360,000	1,700,000	3,214,000

[a] Assumes that each district's fraction of the total is the same as for medium and high scenarios.

[b] Identical to PI-BAU scenario.

[c] Identical to PI-ACC scenario.

[d] Assumes that 1973 production increased at 3%/yr compound growth.

To derive the expected domestically available tonnage by distance, estimates were made of expected district exports of coking coal for 1985 and 2000, assuming that all exported coal would be coking coal in these years. Total exports for 1985 and 2000 are estimated in Section II at 120 and 175 million tons, respectively. Actual export data by district of origin for 1973 are presented in Table A-2, along with the fractional share of district exports. These figures include all export coal shipments reported to the USBM as having destinations in Canada, Mexico, or overseas. To estimate 1985 and 2000 exports by district, it was assumed that each district would have the same fractional share of total future exports as in 1974.

Table A-2

1973 BUREAU OF MINES DISTRICT EXPORTS

(10^3 tons)

District No.	1973 Exports	Fraction of Total Production Exported
1	3,556	0.0690
2	2,096	0.0407
3&6	6,698	0.1299
4	351	0.0068
7	14,902	0.2890
8	23,560	0.4569
13	0	0.
9	99	0.0019
10	126	0.0024
11	0	0.
12	0	0.
14	179	0.0035
15	0	0.
16-23	0	0.
Total	51,567	1.000

Domestically available coal production by USBM District for each scenario was then calculated by subtracting the estimated district exports (Table A-3) from the estimated total production (Table A-1). The resulting estimates of domestically available coal supplies for 1985 and 2000 are presented in Table A-4.

Table A-3

ESTIMATED 1985 AND 2000 EXPORTS[a]

(10^3 tons)

District No.	1985	2000
1	8,280	12,070
2	4,880	7,110
3&6	15,590	22,730
4	820	1,190
7	34,680	50,570
8	54,820	79,950
13	0	0
9	230	340
10	290	430
11	0	0
12	0	0
14	410	610
15	0	0
16-23	0	0
Totals	120,000	175,000

[a]Based on 1974 fraction of production exported.

Table A-4

DOMESTICALLY AVAILABLE COAL SUPPLIES BY BUREAU OF MINES DISTRICT

(10^3 tons)

District No.	1985 Low	1985 Medium	1985 High	2000 Low	2000 Medium	2000 High
1	45,220	51,120	105,020	54,570	76,730	166,950
2	38,920	57,020	96,320	52,730	71,190	134,310
3&6	37,610	45,510	97,710	38,810	65,520	142,470
4	59,080	70,130	130,580	86,530	108,460	197,110
7	7,820	17,670	64,520	8,590	27,880	100,170
8	169,280	224,630	459,480	253,590	346,650	706,520
13	32,500	42,350	77,200	38,760	59,450	110,880
9	67,570	78,520	146,070	98,260	121,910	218,530
10	75,710	87,360	165,110	110,410	136,120	249,300
11	33,100	39,500	70,200	47,600	60,500	107,030
12	1,200	1,650	3,000	2,040	2,550	4,820
14	790	1,240	2,590	1,430	1,940	4,210
15	39,900	60,500	110,800	95,200	102,500	166,160
16-23	145,300	212,800	414,400	296,480	343,600	730,540
Total	754,000	980,000	1,943,000	1,185,000	1,525,000	3,039,000

2. Sulfur Content

In Section II, estimated domestically available future coal supplies are given in various sulfur content categories, based on the distribution by sulfur content of 1970 production for each USBM district. Table A-5 shows these 1970 district production figures, along with the percentage of each district's total production lying within selected categories of sulfur content.

Tables A-6 through A-8 present a breakdown of estimated 1985 district coal production in various sulfur content categories, derived by multiplying the 1970 percentage of district production by sulfur content by the total estimated future district production of Table A-1.

Table A-5

1970 COAL DISTRIBUTION (10^3 TONS) BY SULFUR CONTENT FOR USBM DISTRICTS

	Northern Appalachia				Southern Appalachia		
% S	1	2	3&6	4	7	8	13
<0.5	---	---	23(0.05)	---	2,906(7.83)	6,514(4.05)	----
0.6-1.0	9,940(21.3)[a]	5,156(13.0)	5,900(11.8)	---	33,723(90.82)	120,948(75.10)	10,387(49.91)
1.1-1.3	2,150(4.6)	10,481(27.3)	1,599(3.2)	---	95(0.26)	9,081(5.64)	2,857(49.91)
1.4-1.8	10,117(21.7)	13,783(34.8)	3,938(7.9)	971(1.75)	404(1.09)	15,710(9.76)	3,480(16.72)
1.9-3.0	21,253(45.6)	9,098(23.0)	23,747(47.4)	20,948(37.6)	---	7,193(4.47)	3,916(18.82)
>3.0	3,187(6.8)	741(1.9)	14,846(29.65)	33,780(60.65)	---	1,576(0.98)	171(0.82)
Total	46,647(100)	39,614(100)	50,053(100)	55,699(100)	37,123(100)	161,022(100)	20,811(100)

	Midwest			Near West			Far West
% S	9	10	11	12	14	15	16-23
<0.5	---	----	----	----	---	169(2.22)	6,975(20.39)
0.6-1.0	---	5,728(8.47)	----	----	830(83.0)	157(2.06)	23,938(69.97)
1.1-1.3	---	1,425(2.11)	----	----	---	----	2,973(8.69)
1.4-1.8	---	3,214(4.75)	1,131(5.00)	----	---	1,815(23.80)	177(0.52)
1.9-3.0	4,937(9.25)	9,149(13.52)	8,796(38.85)	164(18.59)	65(6.5)	----	147(0.43)
>3.0	48,423(90.75)		12,714(56.15)	718(81.41)	105(10.5)	5,484(71.92)	----
Total	53,360(100)	67,660(100)	22,641(100)	882(100)	1,000(100)	7,625(100)	34,210(100)

Grand total = 597,812

[a] Numbers in parentheses show the percentage of each district's total production within each category of sulfur content.

Table A-6

ESTIMATED 1985 DISTRICT COAL PRODUCTION BY SULFUR CONTENT - LOW SUPPLY CASE (10^3 TONS)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West
% S	1	2	3&6	4	7	8	13	9	10	11	12	14	15	16-23
<0.5	---	---	30	---	3,330	9,080	----	---	----	----	----	----	880	29,630
0.6-1.0	11,400	5,700	6,280	---	38,600	168,300	16,220	---	6,440	----	----	1,080	820	101,670
1.1-1.3	2,460	11,960	1,700	---	110	12,640	4,460	---	1,600	----	----	----	----	12,630
1.4-1.8	11,610	15,240	4,200	1,050	460	21,870	5,430	---	3,610	1,650	----	----	9,500	750
1.9-3.0	24,400	10,070	25,220	22,520	---	10,010	6,120	6,270	10,280	12,860	200	80	----	620
>3.0	3,360	830	15,770	36,330	---	2,200	270	61,530	54,070	18,590	900	140	28,700	-----
Total	53,500	43,800	53,200	59,900	42,500	224,100	32,500	67,800	76,000	33,100	1,100	1,300	39,900	145,300

Grand total = 874,000

Table A-7

ESTIMATED 1985 DISTRICT COAL PRODUCTION BY SULFUR CONTENT - MEDIUM SUPPLY CASE (10^3 TONS)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West
% S	1	2	3&6	4	7	8	13	9	10	11	12	14	15	16-23
<0.5	---	---	30	---	4,100	11,320	----	---	----	----	----	----	1,340	43,390
0.6-1.0	12,650	6,750	7,210	---	47,550	209,870	21,140	---	7,420	----	----	1,370	1,250	148,900
1.1-1.3	2,730	14,170	1,950	---	130	15,760	5,810	---	1,850	----	----	----	----	18,490
1.4-1.8	12,890	18,060	4,830	1,240	570	27,270	7,080	---	4,160	1,970	----	----	14,400	1,110
1.9-3.0	27,090	11,940	28,960	26,680	---	12,490	7,970	7,280	11,850	15,350	310	110	----	910
>3.0	4,040	980	18,120	43,030	---	2,740	350	71,470	62,370	22,180	1,340	170	43,510	-----
Total	59,400	51,900	61,100	70,950	52,350	279,450	42,350	78,750	87,650	39,500	1,650	1,650	60,400	212,800

Grand total = 1,100,000

Table A-8

1985 DISTRICT COAL PRODUCTION BY SULFUR CONTENT - HIGH SUPPLY CASE (10^3 TONS)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West
% S	1	2	3&6	4	7	8	13	9	10	11	12	14	15	16-23
<0.5	---	---	60	---	7,760	20,830	----	---	----	----	----	----	2,460	84,500
0.6-1.0	24,130	13,150	13,370	---	90,100	386,240	38,530	---	14,000	----	----	2,490	2,280	289,960
1.1-1.3	5,210	27,630	3,630	---	260	29,010	10,600	---	3,490	----	----	----	----	36,010
1.4-1.8	24,590	35,220	8,950	2,300	1,080	50,190	12,910	---	7,850	3,510	----	----	26,370	2,150
1.9-3.0	51,660	23,280	53,700	49,410	---	22,990	14,530	13,530	22,360	27,270	560	190	----	1,780
>3.0	7,710	1,920	33,590	79,690	---	5,040	630	132,770	117,700	39,420	2,440	320	79,690	-----
Total	113,300	101,200	113,300	131,400	99,200	514,300	77,200	146,300	165,400	70,200	3,000	3,000	110,800	414,400

Grand total = 2,063,000

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APPENDIX B

NORTHEAST REGIONAL COAL SUPPLY

Appendix A presented estimates of domestically available coal supply by USBM district for 1985 and 2000 scenarios. Estimates of future coal supply to the Northeast region were derived by assuming that the percentage of each USBM district's domestically available coal supplied to states of the Northeast in 1985 and 2000 would be the same as in 1974.

The 1974 baseline distribution is presented in Table B-1. The percentage distributions in this table were multiplied by the district supply estimates (Table A-4) to obtain state supply estimates for each of the three scenarios for 1985 (Tables B-2 through B-4) and 2000 (Tables B-5 through B-7).

Tables B-8 and B-9 show these results aggregated by coal supply region and subregion of destination for 1985 and 2000, respectively. Figure 10 was based on the estimates in these two tables, while Figure 11 was obtained by multiplying these supply estimates by the average heat value of the coal of each supply region. Tables B-10 and B-11 present in greater detail the subregional breakdown of coal energy supply.

Table B-1

1974 COAL DISTRIBUTION BY STATE OF DESTINATION AND USBM DISTRICT OF ORIGIN (10^3 TONS)

and

Percentage of District Production Distributed to Each State

Origin	Northern Appalachia				Southern Appalachia		
Destination	1	2	3 & 6	4	7	8	13
Maine	29(<1)	--	14(<1)	--	6(<1)	8(<1)	--
Vermont	1(<1)	--	51(<1)	--	--	--	--
New Hampshire	10(<1)	43(<1)	856(3)	1(<1)	--	1(<1)	--
Rhode Island	27(<1)	--	--	--	--	45(<1)	--
Massachusetts	123(<1)	7(<1)	50(<1)	--	20(<1)	549(<1)	--
Connecticut	199(<1)	7(<1)	--	--	--	8(<1)	--
New York	5,619(15)	2,802(8)	1,876(6)	317(1)	287(2)	2,832(2)	--
New Jersey	758(2)	--	1,375(4)	4(<1)	163(1)	757(1)	--
Delaware	732(2)	--	8(<1)	--	--	55(<1)	--
Maryland	4,583(10)	231(1)	1,020(3)	--	253(2)	2,809(2)	--
D.C.	13(<1)	--	102(<1)	--	19(<1)	362(<1)	--
Pennsylvania	26,295(58)	20,195(60)	6,586(20)	359(1)	2,483(17)	7,390(6)	--
TOTAL NORTHEAST	39,369(87)	23,285(69)	11,938(36)	631(2)	3,231(22)	14,816(12)	--
NJ-MD-DE-D.C.	6,086(14)	231(1)	2,505(8)	4(<1)	435(3)	3,983(3)	--
New England	389(1)	57(<1)	971(3)	1(<1)	26(<1)	611(<1)	--
TOTAL U.S.	45,006(100)	33,537(100)	33,073(100)	44,986(100)	14,650(100)	126,749(100)	19,113(100)

Table B-1 (Cont'd)

Origin / Destination	Midwest 9	Midwest 10	Midwest 11	Near West 12	Near West 14	Near West 15	Far West 16-23
Maine	--	--	--	--	--	--	--
Vermont	--	--	--	--	--	--	--
New Hampshire	--	--	--	--	--	--	--
Rhode Island	--	--	--	--	--	--	--
Massachusetts	--	--	--	--	--	--	--
Connecticut	--	--	--	--	--	--	--
New York	--	--	--	--	--	--	9(<1)
New Jersey	1(<1)	--	--	--	--	--	--
Delaware	--	--	--	--	--	--	--
Maryland	--	--	--	--	--	--	--
D.C.	--	--	--	--	--	--	--
Pennsylvania	--	--	--	--	--	13(<1)	21(<1)
TOTAL NORTHEAST	1(<1)	--	--	--	--	13(<1)	30(<1)
NJ-MD-DE-D.C.	1(<1)	--	--	--	--	--	--
New England	--	--	--	--	--	--	--
TOTAL U.S.	52,306(100)	58,848(100)	23,911(100)	597(100)	483(100)	14,981(100)	75,746(100)

GRAND TOTAL USBM DISTRICTS = 543,986 x 10^3

Table B-2

DISTRICT COAL SUPPLIES TO STATES OF DEMAND, 1985 LOW SUPPLY SCENARIO (10^3 tons)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West	Total
Demand Region	1	2	3 & 6	4	7	8	13	9	10	11	12	14	15	16-23	1-23
Maine	29	--	16	--	3	10	--	--	--	--	--	--	--	--	58
Vermont	1	--	58	--	--	--	--	--	--	--	--	--	--	--	59
New Hampshire	10	50	973	1	--	2	--	--	--	--	--	--	--	--	1036
Rhode Island	27	--	--	--	--	61	--	--	--	--	--	--	--	--	88
Massachusetts	123	8	57	--	11	733	--	--	--	--	--	--	--	--	932
Connecticut	200	8	--	--	--	10	--	--	--	--	--	--	--	--	218
New York	6650	3252	2133	417	153	3782	--	--	--	--	--	--	--	17	16404
New Jersey	762	--	1563	5	87	1011	--	1	--	--	--	--	--	--	3429
Delaware	735	--	9	--	--	73	--	--	--	--	--	--	--	--	817
Maryland	4605	268	1160	--	135	3751	--	--	--	--	--	--	--	--	9919
D. C.	13	--	116	--	10	484	--	--	--	--	--	--	--	--	623
Pennsylvania	26420	23436	7490	473	1325	9870	--	--	--	--	--	--	35	41	69090
Total Northeast	39575	27022	13575	896	1725	19787	--	1	--	--	--	--	35	58	102673
Mid-Atlantic States	6115	268	2848	5	232	5319	--	1	--	--	--	--	--	--	14788
New England	390	66	1104	1	14	816	--	--	--	--	--	--	--	--	2391

Table B-3

DISTRICT COAL SUPPLIES TO STATES OF DEMAND, 1985 MEDIUM SUPPLY SCENARIO (10^3 tons)

Demand Region	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West	Total
	1	2	3 & 6	4	7	8	13	9	10	11	12	14	15	16-23	1-23
Maine	33	--	19	--	7	13	--	--	--	--	--	--	--	--	72
Vermont	1	--	70	--	--	--	--	--	--	--	--	--	--	--	71
New Hampshire	11	60	1178	1	--	2	--	--	--	--	--	--	--	--	1252
Rhode Island	31	--	--	--	--	81	--	--	--	--	--	--	--	--	112
Massachusetts	140	10	69	--	24	973	--	--	--	--	--	--	--	--	1216
Connecticut	226	10	--	--	--	13	--	--	--	--	--	--	--	--	249
New York	7518	3929	2581	494	346	5018	--	--	--	--	--	--	--	26	19912
New Jersey	861	--	1892	6	197	1341	--	2	--	--	--	--	--	--	4299
Delaware	831	--	11	--	--	97	--	--	--	--	--	--	--	--	939
Maryland	5212	324	1404	--	305	4978	--	--	--	--	--	--	--	--	12217
D. C.	15	--	140	--	23	642	--	--	--	--	--	--	--	--	820
Pennsylvania	29867	29314	9063	561	2995	13096	--	--	--	--	--	--	53	60	84009
Total Northeast	44740	32647	16427	1062	3897	26254	--	2	--	--	--	--	53	86	125168
Mid-Atlantic States	6913	324	3447	6	525	7058	--	2	--	--	--	--	--	--	18275
New England	442	80	1336	1	31	1082	--	--	--	--	--	--	--	--	2972

Table B-4

DISTRICT COAL SUPPLIES TO STATES OF DEMAND, 1985 HIGH SUPPLY SCENARIO (10^3 tons)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West	Total
Demand Region	1	2	3 & 6	4	7	8	13	9	10	11	12	14	15	16-23	1-23
Maine	67	--	41	--	26	28	--	--	--	--	--	--	--	--	162
Vermont	2	--	150	--	--	--	--	--	--	--	--	--	--	--	152
New Hampshire	23	123	2529	3	--	5	--	--	--	--	--	--	--	--	2683
Rhode Island	63	--	--	--	--	165	--	--	--	--	--	--	--	--	228
Massachusetts	287	20	148	--	88	1990	--	--	--	--	--	--	--	--	2533
Connecticut	464	20	--	--	--	28	--	--	--	--	--	--	--	--	512
New York	15445	8048	5542	921	1264	10265	--	--	--	--	--	--	--	50	41535
New Jersey	1768	--	4062	12	718	2743	--	3	--	--	--	--	--	--	9306
Delaware	1708	--	23	--	--	198	--	--	--	--	--	--	--	--	1929
Maryland	10694	664	3013	--	1114	10182	--	--	--	--	--	--	--	--	25667
D. C.	30	--	301	--	84	1314	--	--	--	--	--	--	--	--	1729
Pennsylvania	61359	58001	19458	1045	10936	26788	--	--	--	--	--	--	96	116	177799
Total Northeast	91910	66876	35267	1981	14230	53706	--	3	--	--	--	--	96	166	264235
Mid-Atlantic States	14200	664	7399	12	1916	14437	--	3	--	--	--	--	--	--	38631
New England	906	163	2868	3	114	2216	--	--	--	--	--	--	--	--	6270

Table B-5

DISTRICT COAL SUPPLIES TO STATES OF DEMAND, 2000 LOW SUPPLY SCENARIO (10^3 tons)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West	Total
Demand Region	1	2	3 & 6	4	7	8	13	9	10	11	12	14	15	16-23	1-23
Maine	35	--	16	--	4	15	--	--	--	--	--	--	--	--	70
Vermont	1	--	60	--	--	--	--	--	--	--	--	--	--	--	61
New Hampshire	12	67	1004	2	--	3	--	--	--	--	--	--	--	--	1088
Rhode Island	33	--	--	--	--	91	--	--	--	--	--	--	--	--	124
Massachusetts	149	11	59	--	12	1098	--	--	--	--	--	--	--	--	1329
Connecticut	241	11	--	--	--	15	--	--	--	--	--	--	--	--	267
New York	8026	4406	2201	610	168	5665	--	--	--	--	--	--	--	36	21112
New Jersey	919	--	1613	8	96	1514	--	2	--	--	--	--	--	--	4152
Delaware	887	--	9	--	--	109	--	--	--	--	--	--	--	--	1005
Maryland	5557	363	1197	--	148	5620	--	--	--	--	--	--	--	--	12885
D. C.	16	--	120	--	11	725	--	--	--	--	--	--	--	--	872
Pennsylvania	31883	31852	7729	692	1456	14784	--	--	--	--	--	--	83	83	88462
Total Northeast	47759	36610	14008	1312	1895	29639	--	2	--	--	--	--	83	119	131427
Mid-Atlantic States	7379	363	2939	8	225	7968	--	2	--	--	--	--	--	--	18914
New England	471	89	1139	2	16	1222	--	--	--	--	--	--	--	--	2939

Table B-6

DISTRICT COAL SUPPLIES TO STATES OF DEMAND, 2000 MEDIUM SUPPLY SCENARIO (10^3 tons)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West	Total
Demand Region	1	2	3 & 6	4	7	8	13	9	10	11	12	14	15	16-23	1-23
Maine	49	--	28	--	11	21	--	--	--	--	--	--	--	--	109
Vermont	2	--	101	--	--	--	--	--	--	--	--	--	--	--	103
New Hampshire	2	91	1696	2	--	4	--	--	--	--	--	--	--	--	1795
Rhode Island	46	--	--	--	--	125	--	--	--	--	--	--	--	--	171
Massachusetts	209	15	99	--	38	1501	--	--	--	--	--	--	--	--	1862
Connecticut	339	15	--	--	--	21	--	--	--	--	--	--	--	--	375
New York	11285	5943	3716	765	546	7744	--	--	--	--	--	--	--	41	30045
New Jersey	1292	--	2724	10	310	2070	--	2	--	--	--	--	--	--	6408
Delaware	1248	--	16	--	--	149	--	--	--	--	--	--	--	--	1413
Maryland	7813	2195	2021	--	481	7682	--	--	--	--	--	--	--	--	20192
D. C.	22	--	202	--	36	991	--	--	--	--	--	--	--	--	1251
Pennsylvania	44830	42868	23650	368	4725	20210	--	--	--	--	--	--	89	96	137336
Total Northeast	67137	51132	34253	1645	6147	40518	--	2	--	--	--	--	89	137	201060
Mid-Atlantic	10375	2195	4963	10	827	10892	--	2	--	--	--	--	--	--	29264
New England	647	121	1924	2	49	1672	--	--	--	--	--	--	--	--	4415

Table B-7

DISTRICT COAL SUPPLIES TO STATES OF DEMAND, 2000 HIGH SUPPLY SCENARIO (10^3 tons)

	Northern Appalachia				Southern Appalachia			Midwest			Near West			Far West	Total
Demand Region	1	2	3 & 6	4	7	8	13	9	10	11	12	14	15	16-23	1-23
Maine	107	--	60	--	41	42	--	--	--	--	--	--	--	--	250
Vermont	3	--	219	--	--	--	--	--	--	--	--	--	--	--	222
New Hampshire	37	172	3687	4	--	7	--	--	--	--	--	--	--	--	3907
Rhode Island	100	--	--	--	--	254	--	--	--	--	--	--	--	--	354
Massachusetts	456	28	215	--	137	3059	--	--	--	--	--	--	--	--	3895
Connecticut	738	28	--	--	--	42	--	--	--	--	--	--	--	--	808
New York	24553	11222	8081	1390	1962	15784	--	--	--	--	--	--	--	88	63080
New Jersey	2811	--	5922	18	1115	4218	--	4	--	--	--	--	--	--	14088
Delaware	2715	--	34	--	--	304	--	--	--	--	--	--	--	--	3053
Maryland	17001	925	4394	--	1730	15656	--	--	--	--	--	--	--	--	39706
D. C.	48	--	439	--	130	2020	--	--	--	--	--	--	--	--	2637
Pennsylvania	97542	80877	28371	1577	16978	41190	--	--	--	--	--	--	145	205	266885
Total Northeast	146111	93252	51422	2989	22093	82576	--	4	--	--	--	--	145	293	398885
Mid-Atlantic States	22757	925	10789	18	2975	22198	--	4	--	--	--	--	--	--	59484
New England	1441	228	4181	4	178	3404	--	--	--	--	--	--	--	--	9436

Table B-8

1985 NORTHEAST COAL SUPPLY SCENARIOS

(10^3 tons)

DEMAND REGION	SUPPLY REGION					
	Northern Appalachia	Southern Appalachia	Midwest	Near West	Far West	Total
New England						
Low	1,561	830	0	0	0	2,391
Medium	1,859	1,113	0	0	0	2,972
High	3,940	2,330	0	0	0	6,270
New York						
Low	12,452	3,935	0	0	17	16,404
Medium	14,522	5,364	0	0	26	19,912
High	29,956	11,529	0	0	50	41,535
Mid-Atlantic						
Low	9,236	5,551	1	0	0	14,788
Medium	10,690	7,583	2	0	0	18,275
High	22,275	16,353	3	0	0	38,631
Pennsylvania						
Low	57,819	11,195	0	35	41	69,090
Medium	67,805	16,091	0	53	60	84,009
High	139,863	37,724	0	96	116	177,799
Total Northeast						
Low	81,068	21,511	1	35	58	102,673
Medium	94,876	30,151	2	53	86	125,168
High	196,034	67,936	3	96	166	264,235

Table B-9

2000 NORTHEAST COAL SUPPLY SCENARIOS

(10^3 tons)

Demand Region	SUPPLY REGION Northern Appalachia	Southern Appalachia	Midwest	Near West	Far West	Total
New England						
Low	1,701	1,238	0	0	0	2,939
Medium	2,694	1,721	0	0	0	4,415
High	5,854	3,582	0	0	0	9,436
New York						
Low	15,243	5,833	0	0	36	21,112
Medium	21,714	8,290	0	0	41	30,045
High	45,246	17,746	0	0	88	63,080
Mid-Atlantic						
Low	10,689	8,223	2	0	0	18,914
Medium	17,543	11,719	2	0	0	29,264
High	34,307	25,173	4	0	0	59,484
Pennsylvania						
Low	72,056	16,240	0	83	83	88,462
Medium	112,216	24,935	0	89	96	137,336
High	208,367	58,168	0	145	205	266,885
Total Northeast						
Low	99,689	31,534	2	83	119	131,427
Medium	154,167	46,665	2	89	137	201,060
High	293,774	104,669	4	145	293	398,885

Table B-10

1985 NORTHEAST COAL ENERGY SCENARIOS

(10^{12} Btu)

DEMAND REGION	SUPPLY REGION					
	Northern Appalachia	Southern Appalachia	Midwest	Near West	Far West	Total
New England						
Low	38.4	21.6	0	0	0	60.0
Medium	45.7	28.9	0	0	0	74.6
High	96.9	60.6	0	0	0	157.5
New York						
Low	306.3	102.3	0	0	0.3	408.9
Medium	357.2	139.5	0	0	0.5	497.2
High	736.9	299.8	0	0	1.0	1037.7
Mid-Atlantic						
Low	227.2	144.3	neg	0	0	371.5
Medium	262.9	197.2	0.1	0	0	460.2
High	548.0	425.2	0.1	0	0	973.3
Pennsylvania						
Low	1422.3	291.1	0	0.8	0.8	1715.0
Medium	1668.0	418.4	0	1.2	1.2	2088.8
High	3440.6	980.8	0	2.1	2.2	4425.7
Total Northeast						
Low	1994.2	559.3	neg	0.8	1.1	2555.4
Medium	2333.8	784.0	0.1	1.2	1.7	3120.8
High	4822.4	1766.4	0.1	2.1	3.2	6594.2

Table B-11

2000 NORTHEAST COAL ENERGY SCENARIOS

(10^{12} Btu)

DEMAND REGION	SUPPLY REGION					
	Northern Appalachia	Southern Appalachia	Midwest	Near West	Far West	Total
New England						
Low	41.8	32.2	0	0	0	74.0
Medium	66.3	44.7	0	0	0	111.0
High	144.0	93.1	0	0	0	237.1
New York						
Low	375.0	151.7	0	0	0.7	527.4
Medium	534.2	2.5.5	0	0	0.8	750.5
High	1113.1	461.4	0	0	1.7	1576.2
Mid-Atlantic						
Low	262.9	213.8	0.1	0	0	476.8
Medium	431.6	304.7	0.1	0	0	736.4
High	844.0	654.5	0.1	0	0	1498.6
Pennsylvania						
Low	1772.6	422.2	0	1.8	1.6	2198.2
Medium	2760.5	648.3	0	2.0	1.8	3412.6
High	5125.8	1512.4	0	3.2	3.9	6645.3
Total Northeast						
Low	2452.3	819.9	0.1	1.8	2.3	3276.4
Medium	3792.6	1213.2	0.1	2.0	2.6	5010.5
High	7226.9	2721.4	0.1	3.2	5.6	9957.2

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APPENDIX C

1974 UTILITY FUEL USE AND EMISSIONS DATA

Appendix C is a compilation of data on actual utility fuel use, cost, generation, and SO_2 emissions for 1974. The sources for these data were Federal Power Commission Form 1 (Annual Report) and 67 (Air and Water Quality Data) filed by each of the region's utility companies. Only steam-electric plants with capacities >25 MW were considered in this study. Tables C-1 through C-3 include a state-by-state analysis of electric utilities indicating plant capacity, 1974 generation, types and amounts of fuel used, average unit cost of the fuel, and the equivalent fuel energy cost in dollars per million Btu, based on the average fuel heating value. Also included are the total energy equivalent of each fuel consumed, the average sulfur content (weight percent) of each fuel, and the calculated 1974 SO_2 emissions for each plant and fuel type in the region. For coal-fired boilers, SO_2 emissions were calculated directly from the following formula:

$$\text{Tons } SO_2 \text{ emitted} = \frac{\%\ S}{100} \times \frac{\text{ton S}}{\text{ton coal}} \times 2\ \frac{\text{ton } SO_2}{\text{ton S}} \times \text{tons coal burned.}$$

For oil-fired boilers, conversion factors[60] were used to calculate SO_2 emissions:

$$\text{Tons } SO_2 \text{ emitted}$$

$$= \frac{\%\ S}{100} \times 2\ \frac{\text{lb } SO_2}{\text{lb S}} \times 7.985\ \frac{\text{lb oil}}{\text{gal oil}} \times 42\ \frac{\text{gal oil}}{\text{bbl oil}} \times \text{bbl oil burned} \times \frac{1}{2000\ \text{lb/ton}}$$

Tables C-1 to C-3 also include compliance SO_2 emissions required by the State Implementation Plans for each plant,[43] which are used in Appendix D.

TABLE C-1

1974 NORTHEAST PLANT EMISSIONS AND SIP EMISSION REQUIREMENTS

State	Utility	Plant	Capacity (MW)	10^6kWh generation	Fuel type	Fuel used	Unit fuel cost[a]	$ per 10^6 Btu	10^{12} Btu consumed	% S	Tons of SO_2 emissions	SIP required SO_2 emissions
Maine	Bangor Hydro-Elec.	Graham	57.4	169.7	#6 Oil	353,168	10.494	1.688	2.19	2.2	2,606	2,961
	Central Maine	Mason	146.5	476.3	#6 Oil	1,037,645	8.42	1.351	6.47	2.15	7,482	8,700
		Wyman	213.6	1,506.4	#6 Oil	2,515,598	9.26	1.484	15.70	2.2	18,560	12,655
New Hampshire	Public Service of N. H.	Schiller	178.75	619.1	Oil	1,195,428	11.053	1.780	7.42	2.1	8,419	8,018
		Merrimack	459.2	2,338.3	Coal Oil	930,819 1,163	21.98 13.90	0.819 2.451	24.96 0.01 24.97	2.3 N.A.	42,816	32,448
		Newington	414.0	299.1	Oil	576,864	12.63	2.036	3.58	1.98	3,831	3,869
Vermont	Burlington Elect. Light	J. Edward Moran	30.0	50.0	Coal Gas	35,900 1,268	38.96 0.79	1.50 1.00	0.930 0.001 0.931	0.87	624	718
Rhode Island	Narragansett Electric	South St.	110.9	625.2	Coal Oil	64,435 1,040,964	37.64 11.28	1.553 1.837	1.56 6.39 7.95	0.03 0.99	1,068 3,456 4,524	1,287 3,491 4,778
		Manchester St.	132.0	548.9	Gas Oil	1,758,729 800,091	1.65 11.37	1.599 1.852	1.01 4.91 6.72	0.99	2,656	2,683
Connecticut	Conn. Light & Power	Montville	577.4	3,390.9	Coal #6 Oil #2 Oil	144,592 4,306,520 10,849	27.549 12.103 11.106	1.136 2.003 1.889	0.35 26.02 0.06 26.43	2.2 0.66 N.A.	635 9,532 10,167	144 7,240 7,384
		Devon	454.0	1,897.2	#6 Oil #2 Oil	3,475,513 11,853	11.996 12.040	1.954 2.048	21.34 0.07 21.41	0.52 0.28	6.061	5,828
		Norwalk Harbor	326.4	1,951.3	#6 Oil #2 Oil	3,216,207 7,248	11.927 12.617	1.970 2.146	19.39 0.04 19.43	0.64 N.A.	6,093	5,303
	Hartford Electric Light	South Meadow	216.8	438.8	#6 Oil	1,009,860	11.894	1.966	6.09	0.44	1,490	1,693
		Middletown	836.9	3,992.5	Coal #6 Oil	159,075 6,269,099	28.243 12.161	1.185 2.013	3.79 37.87 41.66	2.4 0.6	7,633 12,615 20,248	1,590 10,512 12,102
	United Illuminating Co.	English Station	163.2	215.2	Oil	608,817	12.202	1.995	3.72	0.4	817	1,021
		Steel Point	169.5	141.9	Oil	501,591	11.044	1.815	3.05	0.4	673	841
		Bridgeport Harbor	653.0	3,905.3	Oil	6,461,417	11.915	1.950	39.31	0.4	8,668	10,835
Massachusetts	Boston Edison	New Boston	717.7	3,872.5	Oil	6,157,834	11.915	1.959	37.46	0.48	9,913	10,326
		L Street	10.8	62.8	Oil	93,356	11.932	1.956	0.57	0.47	147	157
		Edgar	300.0	1,250.7	Oil	2,279,371	12.114	1.984	13.92	0.93	7,109	7,644
		Mystic-1	150.0	188.1	Oil	642,359	12.550	2.058	3.92	0.69	1,486	1,077
		Mystic-2	468.8	1,867.0	Oil	3,048,036	12.344	2.024	18.59	0.69	7,053	5,111
	Cambridge Electric Light	Blackstone	18.5	27.2	Gas Oil	648,992 157,411	1.694 11.403	1.694 1.867	.65 .96 1.61	0.4	211	264
		Kendall	67.4	331.8	Gas Oil	2,480,953 451,447	1.728 11.138	1.728 1.823	2.48 2.76 5.24	0.4	606	757
	Canal Electric	Canal	542.5	3,379.4	Oil	4,996,205	13.201	2.144	30.77	1.1	18,431	16,756
	Holyoke Water & Power	Riverside	39.75	5.95	Oil	9,890	12.261	2.025	0.06	1.0	33	33
		Mt. Tom	136.0	997.3	Coal Oil	159,960 1,019,300	22.6 11.81	0.927 1.936	0.20 6.22 6.42	2.0 0.9	6,321 3,077 9,398	3,160 3,418 6,578
	Montaup Electric	Somerset	329.0	1,618.1	Oil	3,036,549	10.770	1.755	10.69	0.75	7,638	10,184

(Cont'd.)

TABLE C-1 (cont'd.)

1974 NORTHEAST PLANT EMISSIONS AND SIP EMISSION REQUIREMENTS

State	Utility	Plant	Capacity (MW)	10^6 kWh generation	Fuel type	Fuel used[a]	Unit fuel cost[a]	\$ per 10^6 Btu	10^{12} Btu consumed	% S	Tons of SO_2 emissions	SIP required SO_2 emissions
Massachusetts (cont.)	New Bedford Gas & Edison	Cannon St.	83.0	234.3	Gas	386,571	1.974	1.974	0.39			
					Oil	496,957	13.17	2.158	3.03	1.0	1,667	1,667
									3.42			
	New England Power	Salem Harbor	805.2	4,309.1	Coal	156,608	40.32	1.800	3.56	1.0	3,133	3,133
					Oil	6,693,008	11.63	1.879	41.25	0.76	17,059	22,446
									44.81		20,192	25,579
		Brayton Pt.	1,600.2	5,551.5	Coal	601,813	34.75	1.395	14.81	0.67	8,062	12,033
					Oil	6,069,937	10.33	1.680	38.23	0.90	18,321	20,357
									53.04		26,383	32,390
	Western Mass. Elect.	W. Springfield	209.6	997.8	Gas	1,929,407	1.42	1.420	1.93			
					Oil	1,472,475	10.921	1.490	9.01	0.95	4,691	4,938
									10.94			
	Taunton Municipal Light	Cleary	28.3	106.2	Oil	244,090	4.80	1.102	1.50	.90	737	819
		Taunton (Water St.)	46.0	152.7	Oil	318,850	4.45	.928	1.96	0.90	962	1,069
	Fitchburg G & I	Fitchburg	35.4	96.8	Oil	107,330	13.07	1.704	0.65	0.8	288	360
					Gas	680,800	1.38	1.371	0.69			
									1.34			
New York	Central Hudson	Danskammer	537.4	2,922.9	Oil	4,758,185	9.88	1.591	29.58	2.06	32,872	31,915
		Roseton (20% share)	248.4	209.1	Oil	307,472	7.93	1.272	1.92	1.92	1,980	2,062
	Con. Ed.	Waterside	672.25	1,207.1	Gas	7,079,660	132.746	1.292	7.27			
					Oil	2,359,093	31.541	5.207	14.29	0.35	2,769	2,374
									21.56			
		East River	512.5	1,459.9	Gas	6,490,513	133.537	1.300	6.67			
					Oil	2,087,146	31.319	5.177	12.63	0.38	2,660	2,100
									19.30			
		Hell Gate (retired 12/74)	311.3	5.98	Oil	168,468	31.837	5.270	1.02	0.58	328	169
		Bowline Pt. (share = 2/3)	828.0	2,835.5	Gas	110,672	149.378	1.451	0.11			
					Oil	4,503,178	32.483	5.353	27.87	0.41	6,316	5,700
									27.98			
		Hudson Avenue	715.0	1,055.3	Oil	3,270,161	31.559	5.217	19.78	0.34	3,729	3,290
		Astoria	1,550.6	5,653.2	Gas	3,265,583	132.365	1.289	3.35			
					Oil	9,276,684	31.506	5.261	55.55	0.40	12,444	9,333
									58.90			
		Ravenswood	1,827.7	7,343.5	Gas	1,500,034	130.734	1.273	1.54			
					Oil	11,910,319	31.670	5.257	71.75	0.37	14,779	11,983
									73.29			
		59th St.	184.5	584.0	Gas	12,247	128.116	1.248	0.01			
					Oil	1,436,432	31.580	2.205	8.64	0.47	2,264	1,445
									8.65			
		Roseton (Con. Ed share)	496.8	344.6	Oil	518,574	7.93	1.260	3.23	1.92	3,339	3,478
		Arthur Kill	911.7	2,864.1	Coal	11,020	36.122	1.511	0.26		76	37
					Oil	4,908,451	32.093	2.245	29.47	0.35	5,762	4,938
									29.73		5,838	4,995
		74th Street	209.0	470.2	Oil	1,267,075	31.548	5.250	7.58	0.42	1,778	1,270
	Long Island Lighting Co.	Glenwood	380.2	701.3	Gas	937,729	1.484	1.445	0.96			
					Oil	1,232,377	15.724	2.626	7.38	0.4	1,653	1,529
									8.34			
		Pt. Jefferson	467.0	2,431.9	Oil	4,047,271	9.261	1.490	25.16	2.4	32,370	27,147
		E.F. Barrett	375.0	1,642.5	Gas	1,401,625	1.452	1.415	1.44			
					Oil	2,628,006	14.988	2.496	15.78	0.6	5,288	3,261
									17.22			
		Far Rockaway	113.6	413.6	Gas	690,119	1.523	1.483	0.71			
					Oil	639,635	16.229	2.715	3.82	0.4	858	644
									4.53			
		Northport	1,161.3	7,099.8	Oil	11,021,069	8.956	1.437	68.7	2.5	92,403	73,923
	Orange & Rockland	Lovett	495.1	2,052.3	Gas	6,384,434	1.19	1.158	6.56			
					Coal	86,754	21.40	.854	2.17	2.30	3,985	433
					Oil	2,276,720	14.24	2.457	13.20	0.36	2,749	2,825
									21.93		6,734	3,258

(Cont'd.)

TABLE C-1 (cont'd.)

1974 NORTHEAST PLANT EMISSIONS AND SIP EMISSION REQUIREMENTS

State	Utility	Plant	Capacity (MW)	10^6 kWh generation	Fuel type	Fuel used[a]	Unit fuel cost[a]	\$ per 10^6 Btu	10^{12} Btu consumed	% S	Tons of SO_2 emissions	SIP required SO_2 emissions
New York (cont.)	Orange & Rockland (cont)	Bowline Point (share 1/3)	4,142.0	1,441.9	Gas	184,969	1.34	1.302	0.19			
					Propane	293,369	0.25	2.78	0.02	0.41		
					Oil	7,021,177	13.53	2.228	42.63		6,734	8,712
									42.84			
	Niagara Mohawk	Albany	400.0	2,393.2	Oil	3,876,182	9.34	1.490	24.29	2.53	32,889	25,999
		Dunkirk	628.0	3,046.6	Coal	1,282,420	25.63	1.072	30.72	2.70	69,391	61,918
		C.R. Huntley	828.0	4,758.1	Coal	1,926,422	26.08	1.047	48.24	2.35	91,041	83,293
		Oswego	376.0	1,533.2	Oil	2,888,761	8.68	1.384	17.14	2.60	25,189	19,376
		Roseton (40% share)	496.8	491.9	Oil	515,866	7.93	1.272	4.51	1.92	3,322	3,460
	Rochester Gas & Elec.	Rochester #3	196.2	641.6	Coal	218,665	26.211	1.112	5.15	2,45	10,711	10,711
					#2 Oil	5,050	13.404	2.315	0.03		1,648	
					#6 Oil	275,369	13.731	2.200	1.41	2.18		1,881
									6.59		12,359	12,592
		Rochester #7	[illegible]	[illegible]	Coal	597,953	25.394	1.051	14.45	2.48	29,666	29,187
					Oil	8,052	10.895	1.906	0.05	0.35		540
									14.50		29,666	29,241
	Jamestown Utilities	S.A. Carlson	80.5	181.7	Coal	106,984	23.76	0.978	2.60	2.0	4,284	5,076
	New York State Elec.	Goudey	145.7	774.0	Coal	393,259	19.753	0.927	8.38	2.0	15,447	16,914
		Greenidge	170.0	1,103.1	Coal	577,290	21.360	0.955	12.91	2.1	24,237	25,160
		Jennison	60.0	351.3	Coal	277,446	19.039	0.949	5.57	1.4	7,770	10,989
		Hickling	70.0	541.3	Coal	394,357	10.557	0.522	7.98	1.6	12,625	16,176
		Milliken	270.0	2,040.2	Coal	895,563	23.001	1.056	19.51	2.2	39,403	39,224
New Jersey	Jersey Central	Sayreville	346.8	1,776.1	Gas	650,563	73.68	0.727	0.66			
					Oil	3,167,819	12.59	2.077	19.20	0.5	5,312	5,843
		Werner	116.2	453.0	Oil	927,369	12.64	2.888	5.61	0.4	1,244	1,711
		Gilbert	126.1	639.1	Gas	1,128,692	77.62	0.753	1.16			
					Oil	1,090,184	12.43	2.031	6.67	1.0	3,656	3,656
									7.83			
	Public Service Electric	Bergen	650.4	3,058.0	Coal	306,356	21.294	0.856	7.62	1.4	8,582	1,226
					Gas	657,528	0.713	0.692	0.68			
					Oil	2,636,927	12.654	2.103	21.87	0.4	4,878	6,707
									30.17		13,460	7,933
		Burlington	455.0	1,763.6	Coal	94,360	25.613	1.048	2.31	1.4	2,647	378
					Oil	2,876,287	12.817	2.131	17.30	0.3	2,894	5,305
									19.61		5,541	5,683
		Essex	117.0	370.2	Gas	141,290	0.752	0.729	0.15			
					Oil	960,446	11.973	2.498	4.60	0.4	1,262	1,808
									4.75			
		Hudson	1,114.5	3,303.2	Coal	750,782	28.303	1.169	18.18	1.3	19,524	3,004
					Gas	3,643,509	0.769	0.747	3.75		3,565	
					Oil	1,771,825	12.100	1.995	10.75	0.6		3,268
									32.68		23,089	6,272
		Kearney	314.1	981.8	Coal	10,581	22.964	0.994	0.24	1.1	228	42
					Oil	1,039,551	12.505	2.072	11.09	0.5	3,085	3,389
									11.33		3,313	3,431
		Linden	612.9	2,773.3	Oil	4,033,967	12.566	2.071	20.17	0.5	8,764	7,441
		Marion (retired 1974)	125.0	270.9	Oil	682,026	13.186	2.186	4.11	0.5	1,144	1,258
		Mercer	652.8	2,880.2	Coal	1,079,498	30.148	1.263	25.76	1.5	32,386	4,318
					Gas	2,288,577	0.724	0.703	2.36			
									28.12			
		Sewaren	850.0	3,254.0	Coal	3,599	22.630	0.884	0.09	1.4	98	14
					Gas	1,062,828	0.704	0.683	1.09			
					Oil	6,066,364	12.704	2.118	35.42	0.5	9,837	10,821
									36.60		9,935	10,835
	Vineland Oil Electric Dept.	Down	76.45	274.1	Coal	8,982	25.73	0.940	0.25	2.0	365	182
					Oil	583,696	11.77	1.879	3.63	0.9	1762	1,958
									3.88		2127	2,140

(Cont'd.)

TABLE C-1 (cont'd.)

1974 NORTHEAST PLANT EMISSIONS AND SIP EMISSION REQUIREMENTS

State	Utility	Plant	Capacity (MW)	10^6 kWh generation	Fuel Type	Fuel Used[a]	Unit Fuel Cost[a]	\$ per 10^6 Btu	10^{12} Btu consumed	% S	Tons of SO_2 emissions	SIP required SO_2 emissions
New Jersey (cont.)	Atlantic City Electric	Missouri Ave.	27.0	126.5	Coal	62,965	42.01	1.567	1.69	0.7	882	1,260
					Oil	1,226	10.51	1.813	0.01	0.3		
									1.70			
		Deepwater (DuPont)	308.3	1,575.9	Coal	160,946	28.00	1.165	3.86	2.5	8,039	643
					Gas	1,349,024	0.587	0.571	1.38			
					Oil	2,069,343	12.86	2.158	12.33	0.5	3,470	3,817
									17.57		11,509	4,460
		England	475.6	1,771.5	Coal	619,329	31.60	1.328	14.74	2.7	33,441	12,386
					Oil	495,648	13.10	2.235	2.90	0.8	1,330	1,662
									17.64		34,771	14,048
Pennsylvania	Philadelphia Electric	Cromby	417.5	1,974.1	Coal	356,800	22.84	1.062	8.27	2.3	16,420	2,481
					Oil	1,848,000	11.48	1.885	11.33	0.4	2,479	3,399
									19.60		18,899	5,880
		Eddystone	1,089.8	4,246.0	Coal	1,500,000	23.34	0.958	36.55	2.3	69,008	10,965
					Oil	552,000	12.87	2.146	3.37	0.4	740	1,011
									39.92		69,748	11,976
		Delaware	405.5	1,772.6	Oil	2,944,000	11.77	1.942	17.86	0.5	4,937	2,962
		Richmond	474.8	1,016.2	Oil	2,324,040	11.816	1.951	14.07	0.4	3,118	2,338
		Schuylkill	325.4	1,797.9	Oil	4,234,000	12.21	1.996	25.85	0.5	7,100	4,260
		Southwark	370.0	1,101.5	Oil	3,009,000	11.87	1.955	18.25	0.5	5,046	3,027
		Barbadoes	132.0	484.2	Gas	1,959,000	1.591	1.544	2.02			
					Oil	671,000	11.71	1.904	4.13	0.4	900	675
									6.15			
		Chester	223.0	408.4	Gas	351,000	1.565	1.519	0.36			
					Oil	936,000	11.81	1.939	5.70	0.6	1,003	942
									6.06			
	UGI	Hunlock Creek	93.0	337.3	Coal	295,438	9.18	0.527	5.15	0.7	4,137	10,300
					Oil	25,269	13.26	2.275	0.15	0.3	25	300
									5.30		4,162	10,600
	Metro. Ed.	Portland	426.7	2,248.4	Coal	957,000	23.23	1.000	22.23	2.1	40,195	23,342
					Oil	82,000	13.61	1.924	0.47	0.3	82	71
									22.70		40,277	23,413
		Titus	225.0	1,579.3	Coal	689,000	25.84	1.098	16.22	1.53	21,088	17,031
					Oil	40,500	14.24	2.463	0.23	0.28	38	35
									16.45		21,126	17,066
		Eyler	84.0	52.8	Oil	186,900	13.90	2.302	1.13	1.1	689	777
		Crawford	116.7	306.9	Coal	141,000	24.14	2.175	3.41	1.4	3,945	3,922
					Oil	201,000	13.15	2.302	1.13	0.8	539	1,300
									4.54		4,484	5,222
	Penn. Power & Light	Brunner Island	1,558.7	9,117.8	Coal	3,678,000	21.72	0.883	90.42	2.2	161,832	180,840
					Oil	273,600	11.81	2.035	1.59	0.17	156	238
									92.01		161,988	181,078
		Holtwood	75.0	548.9	Coal	353,800	6.95	0.351	7.00	1.9	13,451	14,000
					Oil	4,300	10.02	1.731	0.02	0.15		
									7.02			
		Martins Creek	312.5	1,780.6	Coal	801,500	28.47	1.176	19.41	2.5	40,073	38,820
					Oil	229,400	11.37	1.963	1.33	0.16	123	200
									20.74		40,196	39,020
		Sunbury	409.8	2,838.4	Coal	1,609,700	12.70	0.568	36.07	2.0	64,393	72,140
					Oil	6,800	13.50	2.352	0.04	0.19		
									36.11			
		Keystone	1,872.0	7,145.2	Coal	3,061,200	12.28	0.524	72.43	2.2	134,697	144,860
					Oil	65,260	14.35	2.462	0.38	0.3	66	57
									72.81		134,763	144,917
		Conemaugh	1,872.0	7,165.4	Coal	3,247,100	16.42	0.739	72.75	2.2	142,864	145,500
					Oil	130,820	14.79	2.537	0.76	0.3	132	114
									73.51		142,996	145,614
		Montour	1,641.7	8,170.2	Coal	3,374,400	20.42	0.843	81.70	1.7	114,728	163,400
					Oil	203,700	13.94	2.428	1.17	0.19	130	2,340
									82.87		114,858	165,740
	Penn. Elect.	Front St.	118.8	622.3	Coal	372,100	22.45	0.944	8.92	2.1	15,633	8,920
					Oil	7,450	13.04	2.238	0.04			
									8.96			

(Cont'd.)

TABLE C-1 (cont'd.)

1974 NORTHEAST PLANT EMISSIONS AND SIP EMISSION REQUIREMENTS

State	Utility	Plant	Capacity (MW)	10^6 kWh generation	Fuel type	Fuel Used[a]	Unit Fuel cost[a]	\$ per 10^6 Btu	10^{12} Btu consumed	% S	Tons of SO_2 emissions	SIP required SO_2 emissions
Pennsylvania (cont.)	Penn. Elect. (cont.)	Saxton (retired 1974)	40.0	102.8	Coal	114,800	14.29	0.571	2.87	1.6	3,671	5,740
		Seward	268.2	1,426.2	Coal Oil	662,400 20,370	13.26 13.86	0.551 2.378	15.90 0.12 16.02	2.8	37,100	31,800
		Shawville	640.0	4,027.8	Coal Oil	1,773,400 53,880	14.78 12.76	0.609 2.189	43.32 0.31 43.63	2.4	85,122	86,640
		Warren	84.6	624.6	Coal	347,200	19.03	0.818	8.34	2.3	15,965	16,680
		Williamsburg	25.0	205.5	Coal	114,600	13.32	0.562	2.79	1.8	4,132	5,580
		Homer City	1,320.0	4,611.4	Coal Oil	2,028,300 90,970	13.29 14.03	0.579 2.406	46.29 0.53 46.82	2.5	101,424	93,640
	Penn. Power Co.	New Castle	425.8	1,981.4	Coal Oil	916,027 5,275	20.82 13.54	0.856 2.053	22.29 0.03 22.32	3.0	54,969	6,696
	West Penn. Power	Armstrong	326.4	1,263.9	Coal Oil	651,100 2,025	25.09 14.00	1.148 2.398	14.23 0.01	1.9	24,750	28,460
		Hilenburg	46.0	169.3	Coal Oil	34,200 250,725	15.126 13.424	0.678 2.315	0.82 1.45 2.27	2.3 0.30	1,565 252 1,817	1,640 218 1,858
		Mitchell	448.7	1,771.4	Coal Gas Oil	562,300 27,800 811,266	16.76 15.77	0.686 2.563	13.73 0.03 4.99 18.75	2.2 0.56	24,739 1,524 26,263	4,119 1,497 5,616
		Springdale	215.4	957.3	Coal Oil	405,400 77,361	19.73 17.50	0.770 2.885	10.39 0.47 10.86	1.6 0.55	12,977 143 13,120	3,117 141 3,258
		Hatfield	1,728.0	3,507.1	Coal Oil	2,844,500 15,468	11.61 14.00	0.490 2.398	67.44 0.09 67.53	2.2 0.25	125,152	134,880
	Duquesne Light	Cheswick	565.0	3,131.2	Coal Oil	1,386,590 65,219	13.46 13.09	0.629 2.189	29.68 0.39 30.07	2.1	58,245	8,904
		Elrama	510.0	3,171.5	Coal #2 Oil	1,576,197 4,875	13.76 13.28	0.635 2.158	34.14 0.03 34.17	2.2	69,358	10,242
		Phillips	411.0	2,120.1	Coal	1,197,326	16.19	0.737	26.40	2.1	50,295	7,920
		Brunot Island	339.0	468.3	Oil	1,138,800	15.57	2.696	6.58	0.30	1,146	2,214
Maryland	Baltimore G & E	Westport	191	664.0	Oil	1,330,370	11.63	1.894	7.66	0.9	3,713	2,063
		Gould St.	173.5	533.8	Oil	1,117,924	11.53	1.876	6.87	0.9	3,374	1,875
		Riverside	333.5	1,350.9	Oil	2,670,910	11.53	1.876	16.41	1.0	8,957	4,479
		Wagner	1,042.6	5,406.3	Coal Oil	652,165 6,299,564	23.72 11.57	0.923	16.76 38.65 55.41	0.9 1.0	11,739 21,127 32,866	13,044 10,563 23,607
		Crane	399.8	2,233.2	Oil	3,806,366	11.70	1.916	23.24	0.9	11,489	6,383
	Delmarva Power & Light	Vienna	230.0	1,075.7	#6 Oil #2 Oil	2,153,635 5,832	12.01 9.82	1.959 1.698	13.21 0.03 13.52	1.01 0.31	7,295 6 7,301	3,617
	Potomac Edison	R. Paul Smith	109.5	557.2	Coal	280,316	21.16	0.964	6.15	1.0	5,605	5,605
	Potomac Electric Power	Chalk Pt.	728.0	2,774.6	Coal #6 Oil #2 Oil	1,127,765 274,635 170,243	28.749 6.989 10.914	1.222 1.113 1.883	26.28 1.71 0.98 28.97	1.84 1.61	41,499 1,483 169 43,151	22,554 632 23,186
		Dickerson	588.0	3,549.1	Coal #2 Oil	1,459,564 266,743	28.348 11.308	1.274 1.944	32.48 1.55 34.03	2.04 1.0	59,543 885 60,428	29,188 268 29,456
		Morgantown	1,252.0	6,906.7	Coal #6 Oil #2 Oil	680,439 7,731,572	26.491 8.591 10.055	1.144 1.374 1.727	16.12 48.34 0.32 64.78	1.94 1.73	26,408 44,857 55 71,320	13,613 13,020 26,633

(Cont'd.)

TABLE C-1 (cont'd.)

1974 NORTHEAST PLANT EMISSIONS AND SIP EMISSION REQUIREMENTS

State	Utility	Plant	Capacity (MW)	10^6 kWh generation	Fuel type	Fuel used[a]	Unit fuel cost[a]	\$ per 10^6 Btu	10^{12} Btu consumed	% S	Tons of SO_2 emissions	SIP required SO_2 emissions
Delaware	Delmarva Power & Light	Edgemoor	389.8	1,899.3	Gas	69,724	14.51		0.72			
					Oil	3,318,720	13.46	2.252	19.84	0.9	10,017	11,130
									20.56			
		Edgemoor #5	445.8	1,626.2	Oil	2,763,775	13.72	2.327	16.30	0.9	8,342	9,269
		Indian River	340.0	2,111.1	Coal	849,453	23.03	0.973	20.12	1.65	28,032	16,989
					Oil	55,499	11.44	1.980	0.32	1.0	186	186
									20.44		28,218	17,175
		Delaware City	55.0	379.9	Coal (Coke)	143,242	15.00		4.06	6.65	19,067	2,867
					Gas	2,572,591	8.77	2.631	2.66			
					Oil	965,824	5.76		5.84	1.21	393	325
									12.56		19,460	3,192
		Delaware City #3	75.0	460.5	Coal (Coke)	53,692	2.16		1.53	6.65	7,154	1,076
					Gas	104,878	2.07	1.712	0.10			
					Oil	624,750	12.60		3.77	1.21	2,535	2,095
									5.40		9,689	3,171
District of Columbia	Potomac Electric Power	Benning Station	719.0	1,972.6	Coal	298,850	39.272	1.562	7.51	0.83	4,958	1,076
					#6 Oil	2,786,286	12.232	1.992	17.11		7,511	9,389
					#2 Oil	13,282	10.962	1.886	0.08			
									24.70	0.80	12,469	15,362
		Buzzard Pt.	27.0	328.8	#6 Oil	728,023	11.276	1.843	4.45	0.96	2,437	2,539
					#2 Oil	28,920	11.023	1.894	0.17			
									4.62			

[a]Oil units are barrels (bbl); costs are \$/bbl.
Gas units are 10^3 standard cubic feet (SCF); costs are \$/10^3 SCF.
Coal units are tons; costs are \$/ton.

TABLE C-2

1974 ELECTRIC UTILITY DATA

STATE TOTALS

State	Capacity (MW)	Generation (10^5 kWh)	Fuel type (% of total)	Units of fuel used[a]	10^{12} Btu fuel used	Average heat value[a]	Total fuel cost (10^6 $)	Average % S	SO_2 emissions (tons)	SIP required emissions (tons)	% required
Maine	417.5	2,152.4	Coal (0)	0	0	0	-	-	-	-	-
			Gas (0)	0	0	0	-	-	-	-	-
			Oil (100)	3,906,411	24.4	6.25 x 10^6	39.455	2.19	28,648	24,316	15
Vermont	30.0	50.0	Coal (99.9)	35,900	0.930	25.91 x 10^6	1.399	0.87	624	718	NONE
			Gas (0.1)	1,268	.001	1,000	0.001	-	-	-	-
			Oil (0)	0	-	-	-	-	-	-	-
					0.931		1.400				
New Hampshire	1,052.0	3,256.5	Coal (69.4)	930,819	25.0	32.23 x 10^6	20.250	2.77	42,816	32,448	24
			Gas (0)	0	0	0	-	-	-	-	-
			Oil (30.6)	1,773,445	11.0	6.20 x 10^6	20.284	2.06	12,250	11,887	3
					36.0		40.534		55,066	44,335	19
Rhode Island	242.9	1,174.1	Coal (10.6)	64,435	1.56	24.21 x 10^6	2.459	0.83	1,068	1,287	NONE
			Gas (12.4)	1,758.729	1.82	1,035	1.607	-		-	-
			Oil (77.0)	1,841.055	11.30	6.14 x 10^6	21.820	0.99	6,112	6,174	NONE
					14.68		25.886		7,180	7,461	
Connecticut	3,392.2	14,843.1	Coal (2.5)	1[illegible]3 534	4.1	23.63 x 10^6	4.531	2.35	8,268	1,734	79
			Gas (0)	0	0	0	-	-	-	-	-
			Oil (97.5)	25,378,954	157.0	6.07 x 10^6	323.263	0.54	46,759	43,363	7
					161.1		327.794		55,027	45,097	18
Massachusetts	5,626.2	25,043.8	Coal (7.3)	9[illegible]8,385	18.57	20.22 x 10^6	24.884	0.95	17,516	18,326	NONE
			Gas (2.4)	6,126,724	6.14	1,002	8 854	-	-	-	-
			Oil (90.3)	37,2[illegible]4,405	229.45	6.15 x 10^6	446 969	0.79	99,429	108,013	NONE
					254.16		480 707		116,945	126,339	
New York	16,385.2	61,903.9	Coal (22.8)	6,770,133	158.0	23.34 x 10^6	167.638	2.28	308,636	299,138	3
			Gas (4.1)	28,057,595	28.3	1,026	19.314	-	-	-	-
			Oil (73.1)	83,585,136	507.4	6.07 x 10^6	1,028.500	1.07	299,249	248,868	17
					694.2		1,215.952		607,885	548,006	10
New Jersey	5,368.1	25,221.4	Coal (27.9)	3,097,398	74.7	24.05 x 10^6	100.397	1.71	106,192	23,453	78
			Gas (4.2)	10,928,011	11.2	1,025	7.918	-	-	-	-
			Oil (67.9)	29,993,578	181.7	6.00 x 10^6	383.656	0.50	50,203	58,644	NONE
					267.6		495.971		156,395	82,097	48
Delaware	1,305.6	6,477.0	Coal (34.4)	1,04[illegible],387	25.7	24.56 x 10^6	23.373	2.59	54,253	20,932	61
			Gas (3.8)	2,74[illegible],[illegible]93	2.8	1,019	5.071	-	-	-	-
			Oil (61.8)	7,728,576	46.1	5.96 x 10^6	108.541	0.83	21,473	23,005	NONE
					74.6		136.985		75,726	43,937	42
Maryland	5,050.9	24,941.5	Coal (38.0)	4,200,249	97.9	23.31 x 10^6	118.361	1.72	144,794	84,004	42
			Gas (0)	0	0	0	-	-	-	-	-
			Oil (62.0)	25,732,425	158.8	6.16 x 10^6	292.668	1.20	103,410	42,900	59
					256.7		411.029		248,204	126,904	49
District of Columbia	746.0	2,301.4	Coal (25.6)	298,850	7.5	25.10 x 10^6	12.630	0.80	4,958	5,973	NONE
			Gas (0)	0	0	0	-	-	-	-	-
			Oil (74.4)	3,556,911	21.8	6.13 x 10^6	43.578	0.83	9,948	11,928	NONE
					29.3		56.208		14,906	17,901	
Pennsylvania	19,637.0	84,253.2	Coal (86.6)	35,238,278	819.2	23.26 x 10^6	642.221	2.15	1,516,748	1,282,579	15
			Gas (0.3)	2,337,800	2.4	1,031	3.711	-	-	-	-
			Oil (13.1)	20,510.653	124.0	6.05 x 10^6	255.812	0.44	30,559	28,116	8
					945.6		901.744		1,547,307	1,310,695	15

[a]Oil units are barrels (bbl); heat values are BTU/bbl.
Coal units are tons; heat values are BTU/ton.
Gas units are 10^3 standard cubic feet (SCF); heat values are BTU/SCF.

TABLE C-3

1974 ELECTRIC UTILITY DATA

SUBREGION AND REGION TOTALS

Region	Capacity	Generation	Fuel type (% of total)	Units of fuel used[a]	10^{12} Btu fuel used	Total fuel cost (10^6 $)	Average % S	SO_2 Emissions (tons)	SIP required emissions (tons)	% Reduction required
New England	10,760.8		Coal (10.2)	2,123,073	50.2	53.523	1.66	70,292	54,513	22
		46,791.9	Gas (1.6)	7,886,721	8.0	10.462	-	-	-	-
			Oil (88.2	70,694,270	433.1	851.791	0.82	193,198	193,753	none
					491.3	915.776		263,490	248,266	6
New York	16,385.2	61,903.9	Coal (22.8)	6,770,133	158.0	167.638	2.28	308,636	299,138	3
			Gas (4.1)	28,057,595	28.8	19.814	-	-	-	-
			Oil (73.1)	83,585,136	507.4	1,028.500	1.07	299,249	248,868	17
					694.2	1,215.952		607,885	548,006	10
MD-DE-DC-NJ	12,470.6	58,941.3	Coal (32.8)	8,642,883	205.8	259.761	1.79	310,197	134,362	57
			Gas (2.2)	13,669,204	14.0	12.989	-	-	-	-
			Oil (65.0)	67,067,230	408.4	828.443	0.82	185,034	136,477	26
					628.2	1,101.193		495,231	270,839	45
Pennsylvania	19,637.0	84,253.2	Coal (86.6)	35,238,278	819.2	642.221	2.15	1,516,748	1,282,579	15
			Gas (0.3)	2,337,800	2.4	3.711	-	-	-	-
			Oil (13.1)	20,510,653	124.0	255.812	0.44	30,559	20,116	8
					945.6	901.744		1,547,307	1,310,695	15
Total Northeast	59,253.6	251,618.3	Coal (44.7)	52,774,368	1,233.1	1,123.143	2.09	2,205,873	1,770,592	20
			Gas (1.9)	51,951,320	53.2	46.976	-	-	-	-
			Oil (53.4)	241,852,220	1,473.0	2,964.546	0.87	708,040	607,214	14
					2,759.3	4,134.665		2,913,913	2,377,806	18

[a]Oil units are barrels (bbl).
Coal units are tons.
Gas units are 10^3 standard cubic feet (SCF).

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APPENDIX D

CONVERSION CASE CALCULATIONS

This Appendix D deals with cost estimates and SO_2 emission calculations for each of the conversion scenarios discussed in Section IV, as well as the case of compliance with the 1974 fuel mix. Conversion Case I represents conversion of plants that have already received orders of intent from the Federal Energy Administration (under authority of the Energy Supply and Environmental Coordination Act of 1973) to prohibit the burning of fuel oil. Case II includes the same plants as Case I plus seven others judged "feasibly" convertible by FEA and EPA. Case III includes several plants that might be able to burn coal if state emission regulations were relaxed in areas where they may be more stringent than needed to attain air quality standards.

1. Compliance Using 1974 Fuel Mix

Let us consider first the costs associated with State Implementation Plan (SIP) compliance by all regional power plants. Appendix C presented data on SIP required emissions and current fuel type for each plant in the region. Table D-1 presents actual and required 1974 SO_2 emissions for oil and coal-fired plants in the region and shows that for compliance a 20% reduction in coal-related emissions and a 14% reduction in oil-related emissions are required. This can be taken to indicate that compliance requires coal with 20% lower average sulfur content and oil with 14% lower average sulfur content. The regression analysis discussed in Section IV suggested that each 0.1% decrease in sulfur content would raise the price of coal by about 8¢/10^6 Btu, and oil by about 5¢/10^6 Btu. On this basis, the estimated total added cost of higher quality fuels to meet SIP emission regulations in the region is $\sim$ \$503 million (Table D-1).

2. Conversion Scenarios

For the three conversion cases, cost estimates include the cost of converting from oil to coal and the increase or decrease in fuel expenses due to conversion. For Case 1, the additional coal required and fuel oil savings were based on estimates made by FEA.[37] The unit cost (per ton) of the additional coal required for conversion was based on average 1974 state coal prices (see

Table D-1

COMPLIANCE CASE COST CALCULATIONS

Fuel	1974 SO_2 emissions (10^3 tons)	Required SIP emissions (10^3 tons)	% Reduction required	1974 Average % S	Required reduction in % S for compliance	Approximate fuel premium ($\$/10^6$ Btu)	Total 1974 energy use (10^{12} Btu)	Increased fuel cost (10^6 \$)
Oil	708.0	607.2	14	0.87	0.12	0.060	1,473	88.4
Coal	2,205.9	1,770.6	20	2.09	0.42	0.336	1,233	414.3
Total	2,913.9	2,377.8	18					502.7

Appendix C). The unit cost (per barrel) of oil was also based on actual average 1974 prices paid by each plant (Appendix C). The total cost was amortized assuming a 15-year project lifetime and an interest rate of 9%. Most operating and planned scrubbing systems actually are expected to have longer lifetimes and lower interest rates. The parameters were chosen conservatively to represent reasonable upper bound. To obtain the annual conversion cost, the capital recovery factor of 0.124 was multiplied by the total plant conversion costs (Table 15). The results for Case 1 are given in Table D-2. The right-hand column represents total yearly savings over the 1974 (base) case and is derived as follows:

(Net annual savings) = (fuel oil savings) - (additional coal cost)
- (annual conversion cost).

The new (after conversion) costs of fuel for the region are calculated by subtracting the net annual saving from the actual 1974 fuel cost.

For Case 2, the unit cost of coal after conversion was estimated by Foster Associates[36] on the basis of the location of available coal for the plant, its present cost at the mine, and the estimated transportation cost. These coal cost estimates were used together with estimates of the needed additional coal tonnage made by PedCo Environmental Specialists[35] to calculate the additional coal cost due to conversion. Preconversion fuel oil use by the convertible units, as estimated by PedCo, was used together with the average 1974 oil cost to each plant to determine total fuel cost savings for the conversion case. Total capital conversion cost estimates for each plant (Table 16) were placed on an annual basis, again assuming a 15-year project life and a 9% interest rate. The capital cost estimates of Table 16 are utilized here because they were the only plant-specific cost estimates available. Several other studies have been done to estimate scrubber costs as a function of plant size and coal characteristics. Scrubber cost estimates in a study done at Carnegie-Mellon University[33] are generally lower than those made by PedCo. Thus, the PedCo figures may again be a conservative (high) estimate of scrubber costs. Actual scrubber costs are highly dependent, however, on inflation rates and availability, which are difficult parameters to estimate. In Table D-3, the annual conversion operating cost reflects the operating costs of flue-gas desulfurization systems. The final column again presents the net annual savings for each plant, calculated as

Table D-2

CONVERSION CASE 1--COST CALCULATIONS

Plant	Coal requirement (10^3 tons)	Unit coal cost ($/ton)	Additional coal cost (10^6 $)	Fuel oil savings (10^3 bbl)	Fuel oil unit cost ($/bbl)	Fuel oil savings (10^6 $)	Annual conversion cost (10^6 $)	Net annual savings (10^6 $)
Schiller, NH	175	21.76	3.83	668	11.05	7.38	0.30	3.25
Danskammer, NY	917	24.76	22.70	3,644	9.88	36.00	2.48	10.82
Albany, NY	1,041	24.76	25.78	3,876	9.34	36.20	1.12	9.30
England, NJ	836	32.41	27.09	3,396	13.10	44.49	0.40	17.00
Edgemoor, DE	833	27.12	22.59	3,319	13.46	44.67	1.61	20.47
Morgantown, MD	2,041	28.18	57.52	7,732	8.59	66.42	0.18	8.72
Crane, MD	976	28.18	27.50	3,806	11.70	44.53		
Riverside, MD	198	28.18	5.58	836	11.53	9.64	2.45[a]	30.69
Wagner, MD	594	28.18	16.74	2,488	11.57	28.79		
Total	7,612		209.33	29,765		318.12	8.54	100.25

[a]Conversion costs for Crane, Riverside, and Wagner were considered together.

Table D-3

CONVERSION CASE 2--COST CALCULATIONS

Plant	New coal required (10^3 tons)	Unit coal cost (\$/ton)	Additional new coal cost (10^6 \$)	Fuel oil savings (10^3 bbl)	1974 oil cost (\$/bbl)	Total fuel oil savings (10^6 \$)	Annual operating cost (10^6 \$)	Annual capital cost (10^6 \$)	Net annual savings (10^6 \$)
Schiller, NH	176	35.50	6.25	668	11.05	7.38	0.00	0.29	0.84
Danskammer, NY	1,200	28.94	34.73	4,757	9.88	47.00	4.50	2.98	4.79
Albany, NY	1,041	28.94	30.13	3,876	9.34	36.20	4.64	4.62	-3.19
England, NJ	836	30.02	25.10	3,396	13.10	44.49	0.00	0.40	18.99
Edgemoor, DE	833	29.09	24.23	3,319	13.46	44.67	3.76	3.94	12.74
Morgantown, MD	2,041	27.25	55.62	7,732	8.59	66.42	1.86	10.82	8.12
Crane, MD	976	31.55	30.79	3,806	11.70	44.53	4.73	4.42	4.59
Riverside, MD	406	32.69	13.27	1,713	11.53	19.75	3.17	2.25	1.06
Wagner, MD	594	42.46	25.22	2,488	11.57	28.79	1.79	1.56	0.22
Gould Street, MD	185	32.19	5.96	781	11.53	9.00	0.89	0.49	1.66
Salem Harbor, MA	549	35.77	19.64	3,027	11.63	35.20	7.30	3.22	5.04
Brayton Pt., MA	2,357	35.77	84.31	10,873	10.33	112.32	4.35	8.51	15.15
Mt. Tom, MA	422	30.20	12.74	1,661	11.81	19.62	1.96	1.44	3.48
W. Springfield, MA	455	30.20	13.74	1,472	10.92	16.07	1.93	1.07	-0.67
Somerset, MA	500	29.37	14.68	1,986	10.77	21.39	2.07	2.61	2.03
South Street, RI	241	29.40	7.08	952	11.28	10.74	1.65	1.69	1.66
Total	12,812		403.49	52,507		563.57	44.60	40.31	75.17

(Net annual savings) = (fuel oil cost savings) - (additional coal cost) - (annual operating cost) - (annual capital cost).

A negative value indicates that conversion will cost more than the 1974 base case. For the region as a whole Table D-3 indicates that Case 2 provides a net savings of $75 million over the 1974 base case. An analysis of the sensitivity of this result to changes in fuel, capital, and interest costs was outside the scope of this study, but would be useful in future studies.

Cost calculations for Case 3 are presented in Table D-4. Here, the plant conversion costs are assumed to be comparatively small (as substantiated by typical Case I costs for simple conversion back to coal), so that the difference between oil and coal costs approximates the net annual savings. Unit coal cost was again based on 1974 state averages, while oil cost was based on actual 1974 plant cost. Net annual savings for the entire Northeast region due to Case 3 alone are ∿ $83 million dollars on this basis. This, combined with Case 2 savings of $75 million yields a total annual saving of $158 million for the combined (Case 2 and Case 3) conversion scenario.

3. Emission Calculations

To derive the social cost estimates in Section IV, changes in SO_2 emissions were calculated for each of the scenarios considered. Emissions for actual 1974 fuel use and for the case of compliance using the 1974 fuel mix are given in Appendix C. For the three conversion cases, assumptions were made regarding the sulfur content of coal utilized after conversion. For Case 1, it was assumed that compliance coal would be utilized since no other sulfur oxide control measures were to be instituted. For Case 2, the sulfur content of available coal as reported by Foster Associates was also adopted here. For Case 3, coal with a 1.5% average sulfur content was assumed. The 1.5% level was used in most of the modeling studies[39-41] to demonstrate the feasibility of conversion. Although it is possible that higher sulfur coal could be utilized at some plants, the 1.5% level was chosen as a likely average for all the plants. Section II indicated that such coal could also be available in sufficient quantities by 1985.

Table D-4

CONVERSION CASE 3--COST CALCULATIONS

Plant	Coal requirement (10^3 tons)	1974 Unit coal cost ($/ton)	Total Coal cost (10^6 $)	Fuel oil savings (10^3 bbl)	1974 Unit oil cost ($/bbl)	Total oil savings (10^6 $)	Net annual savings (10^6 $)
Sayreville, NJ	692	32.41	22.43	2,264	12.59	28.50	6.07
Weiner, NJ	161	32.41	5.22	479	12.64	6.05	0.83
Bergen, NJ	1,259	32.41	41.13	3,636	12.65	46.00	4.87
Burlington, NJ	395	32.41	12.80	1,220	12.82	15.64	2.84
Sewaren, NJ	209	32.41	6.77	821	12.78	10.49	3.72
Barrett, NY	439	24.76	10.87	1,226	14.99	18.38	7.51
Far Rockaway, NY	161	24.76	3.99	561	16.23	9.10	5.11
Port Jefferson, NY	842	24.76	20.85	3,033	9.26	28.09	7.24
Montville, CT	380	26.11	9.92	1,450	11.11	16.11	6.19
Devon, CT	950	26.11	24.80	3,284	12.00	39.41	14.61
Norwalk Harbor, CT	944	26.11	24.65	3,216	11.93	38.37	13.72
Middletown, CT	494	26.11	12.89	1,940	12.16	23.59	10.70
Delaware City, DE	766	27.11	20.77	1,591	12.60	20.05	-0.72
Total	7,702		217.09	24,721		299.78	82.69

Additional SO_2 emissions due to increased coal use in each of the conversion cases were estimated from the additional coal requirements in Table D-2 to D-4 by using the estimated sulfur content of available coal. The corresponding reduction in emissions from combustion of fuel oil was calculated on the basis of the actual 1974 conditions summarized in Appendix C.

The total change in emissions for the three conversion cases is presented in Tables D-5 through D-7. A positive sign indicates increased emissions due to conversion; a negative sign, reduced emissions. For SO_2 emissions in Case 2, a 90% SO_2 removal efficiency with use of stack-gas scrubbers was assumed. This scenario results in reduced regional emissions after conversion, while in the other two scenarios, conversion results in a net increase in regional SO_2 emissions relative to 1974.

Table D-5

CONVERSION CASE 1--EMISSION CALCULATIONS

Plant	1974 SO_2 emissions (tons)	Additional coal requirement (10^3 tons)	% S Coal[a]	Additional emissions (tons)	Fuel oil savings (10^3 bbl)	% S Oil[b]	Reduced emissions (tons)	Total change in emission (tons)
Schiller, NH	8,419	176	2.0	6,899	668	2.1	4,705	+2,194
Danskammer, NY	32,872	917	2.0	35,946	3,644	2.06	25,175	+10,771
Albany, NY	32,889	1,041	2.0	40,807	3,876	2.53	32,889	+7,918
England, NJ	34,771	836	1.0	16,386	3,396	0.8	9,111	+7,275
Edgemoor, DE	18,359	833	1.0	16,327	3,319	0.9	10,018	+6,309
Morgantown, MD	71,320	2,041	1.0	40,003	7,732	1.73	44,860	-4,857
Crane, MD	11,489	976	1.0	19,130	3,806	0.9	11,488	+7,642
Riverside, MD	8,957	198	1.0	3,881	836	1.0	2,804	+1,077
Wagner, MD	32,866	594	1.0	11,642	2,488	1.0	8,344	+3,298
Total	251,942	7,612		+191,021	29,765		-149,394	+41,627

[a]Based on compliance coal.[43]

[b]Based on 1974 actual use.

Table D-6

CONVERSION CASE 2--EMISSION CALCULATIONS

Plant	1974 Emissions	Additional coal requirement (10^3 tons)	% S coal[a]	Additional emissions (tons)	Additional controlled emissions (tons)	Fuel oil savings (10^3 bbl)	% S oil[b]	Reduced emissions (tons)	Total change in emissions (tons)
Schiller, NH	8,419	176	1.0	3,450	3,450	668	2.1	4,705	-1,255
Danskammer, NY	37,872	1,200	2.2	51,744	51,744	4,757	2.06	32,872	+18,872
Albany, NY	32,889	1,041	2.5	51,009	5,100	3,376	2.53	32,889	-27,789
England, NJ	34,771	836	1.0	16,386	16,386	3,396	0.8	9,111	+7,275
Edgemoor, DE	18,359	833	3.0	48,980	4,898	3,319	0.9	10,018	-5,170
Morgantown, MD	71.320	2,041	1.0	40,004	40,004	7,732	1.73	44,860	-4,856
Crane, MD	11.489	975	2.5	47,824	4,782	3,306	0.9	11,489	-6,707
Riverside, MD	8.957	405	1.0	7,958	7,958	1,713	1.0	5,745	+2,213
Wagner, MD	32.866	591	1.0	11,642	11,642	2,488	1.0	8,344	+3,298
Gould St., MD	3.374	185	1.0	3,626	3,626	781	0.90	2,357	+1,269
Salem Harbor, MA	20,192	549	2.5	26,901	2,690	3,027	0.76	7,715	-5,025
Brayton Pt., MA	26,383	2,357	2.5	115,493	11,549	10,873	0.90	32,818	-21,269
Mt. Tom, MA	9,398	422	2.5	20,678	2,068	1,661	0.90	5,013	-2,945
W. Springfield, MA	4,691	455	2.5	22,295	2,230	1,492	0.95	4,691	-2,461
Somerset, MA	7,638	500	2.5	24,500	2,450	1,986	0.75	4,995	-2,545
South St., RI	4,524	241	2.5	11,809	1,181	952	0.99	3,161	-1,980
Total	328,142	12,812		504,299	171,758	57,507		220,783	-49,075

[a]Based on Foster Associates Estimates.[36]

[b]Based on 1974 actual use.

Table D-7

CONVERSION CASE 3--EMISSION CALCULATIONS

Plant	Additional coal requirement	% S coal	Additional emissions (tons)	Oil savings	% S oil	Reduced oil emissions (tons)	Total change in emissions (tons)
Sayreville, NJ	692	1.5	20,345	2,264	0.5	3,796	+16,549
Werner, NJ	161	1.5	4,733	479	0.4	643	+4,090
Bergen, NJ	1,269	1.5	37,309	3,636	0.4	4,878	+32,431
Burlington, NJ	395	1.5	11,613	1,220	0.3	1,227	+10,386
Sewaren, NJ	209	1.5	6,145	821	0.5	1,377	+4,768
Barrett, NY	439	1.5	12,907	1,226	0.6	2,467	+10,440
Far Rockaway, NY	161	1.5	4,733	561	0.4	753	+3,980
Montville, CT	380	1.5	11,172	1,450	0.66	3,209	+7,963
Devon, CT	950	1.5	27,930	3,204	0.52	5,588	+22,342
Norwalk Harbor, CT	944	1.5	27,754	3,216	0.64	6,903	+20,851
Middletown, CT	494	1.5	14,525	1,940	0.6	3,904	+10,621
Delaware City, DE	766	1.5	22,520	1,591	1.21	6,456	+16,064
Total	7,702		226,441	24,641		65,613	+160,828

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APPENDIX E

COMPARATIVE ECONOMICS OF FUTURE OIL AND COAL-FIRED GENERATING CAPACITY

The present trend of electric utilities in the Northeast is to plan for a mix of future generating capacity, including new fossil-fuel plants, to avoid relying too heavily on any single source of energy supply. In terms of purely economic considerations, electric utilities traditionally use a present-worth investment analysis to determine the best choice among different alternatives. For any planned level of capacity, future revenues are the same under all generating alternatives, and a decision is based upon the minimum cost alternative.

In terms of fossil-fuel electrical generation in the Northeast, the choice is between oil and coal-fired capacity since use of natural gas by new plants is unlikely, given present and projected supply shortages. The mix of coal and oil planned for 1985 was discussed previously in Section IV.

This appendix examines the conditions under which it may be economically favorable to use coal rather than oil in future fossil-fuel plants. Given the uncertainties in estimating future costs, the data presented here are to be considered illustrative, with emphasis on the methodology used to determine a least-cost option for a given set of conditions. A sensitivity analysis of the importance of different assumptions was beyond the scope of this study, but such an analysis is contained in references 57 and 59. Also, because the choice here is between only two alternatives, the relative differences between cost estimates are more important than the absolute magnitudes of the estimates.

To illustrate one methodology for choosing between future generating alternatives, consider a 1000 MW steam electric plant to begin operation in 1985. Table E-1 summarizes assumptions made regarding plant operating characteristics. The primary source of data on capital costs for both oil and coal-fired plants is a study performed for the Atomic Energy Commission (AEC) in 1972.[55,56] The prices cited in the study were for construction completed in January 1971. The AEC updated these cost estimates in 1974 to reflect rapid inflation.[57] Projections made in 1974 for 1981 construction completion are used here as the basis for analysis. The cost estimates for 1981 assumed escalation rates of 5%/yr for equipment and material and 10%/yr for labor. The compound interest rate was assumed to be 7 1/2%/yr, with a 6-yr period required for construction. To

Table E-1

OPERATING CHARACTERISTICS OF A 1000-MW PLANT

Average load factor	60%[a]
Estimated plant lifetime	35 yr
Average plant heat rate	10,000 Btu/kWh
Initial plant operation	1985
SO_2 control (FGD system) for coal-fired plants	
Optional SO_2 control for oil-fired plants	

[a]Averaged over total lifetime of plant.

extend a 1981 completion date to 1985, an estimate of future escalation rates made by Oak Ridge National Laboratory was applied to the AEC 1981 data.[58] The resulting capital cost estimates for 1985 completion of the plant are presented in Table E-2.

Table E-2

CAPITAL COST ESTIMATES FOR A 1000-MW PLANT

	10^6 \$
1981 Commercial Operation[a]	
Coal (with SO_2 control)	485
Oil (with SO_2 control)	438
Oil (without SO_2 control)	372
1985 Commercial Operation[b]	
Coal (with SO_2 control)	655
Oil (with SO_2 control)	591
Oil (without SO_2 control)	502

[a]Ref. 57.

[b]Ref. 58. 1985 costs are scaled to be 1.35 times 1981 costs.

In terms of the utility investment decision, two cost components must be considered. The first is the annual fixed charge, which includes an acceptable rate of return on investment, plant depreciation, insurance, taxes, and administrative expanses. An estimated annual percentage of invested capital for each of these components is presented in Table E-3. The annual fixed charge assumed in this analysis is 16.23% of capital, with a minimum acceptable rate of return of 8%.

Table E-3

ASSUMED ANNUAL FIXED CHARGE RATE[59]

(Percent of capital)

Return	8.00
Depreciation	0.58
Administrative and general	1.25
Insurance	0.10
Ad valorem taxes	2.25
Income tax	4.05
Total	16.23

The second component is the annual variable expense, which includes operation and maintenance costs and fuel expense. The annual operation and maintenance expense estimated for 1985 is presented in Table E-4. A 1974 cost of 1.0 mills/kWh is assumed for oil-fired plants (without SO_2 control), and 1.5 mills/kWh for coal-fired plants (without SO_2 control).[59] The operating costs for stack-gas scrubbing units were derived from estimates prepared by the Tennessee Valley Authority for the U.S. Environmental Protection Agency, assuming a limestone scrubber.[34] The actual cost of 1985 operation and maintenance was then estimated, assuming an 8% inflation rate and plant characteristics given in Table E-1.

Fuel expense is treated as a variable in this analysis. Different costs for oil in 1985 are considered, together with the break-even price for coal-fired generation. It is assumed that a coal-fired plant will be built with SO_2

Table E-4

OPERATION AND MAINTENANCE ANNUAL COST ESTIMATES FOR A 1,000-MW PLANT[33,59]

	10^6 \$/yr
1974 Estimate	
Coal (no SO_2 control)	7.9
Oil (no SO_2 control)	5.3
Limestone scrubber operating cost at 2.13 mills/kWh	11.2
Coal (SO_2 control)	19.1
Oil (SO_2 control)	16.5
Oil (no SO_2 control)	5.3
1985 Projection (8% inflation)	
Coal (SO_2 control)	44.5
Oil (SO_2 control)	38.4
Oil (no SO_2 control)	12.3

controls while an oil-fired plant will not. It is also assumed that prices of oil and coal after 1985 will inflate at the same rate of 8%. (Other assumptions regarding relative fuel costs over the plant lifetime could be considered in an alternative analysis.) The present value factor at an 8% rate of return was used to calculate the present worth of a 1000-MW oil-fired plant in 1985, as a function of varying oil prices. The 8% rate of return is only illustrative; the actual rate will vary with the utility.

The price of coal was determined at which a 1985 coal-fired plant would have the same present worth as the oil-fired unit. At coal prices above that level, oil-fired generation would be more economical than coal. Table E-5 presents the results of the present-worth analysis as a function of the assumed 1985 price of oil. The last two columns show the price of coal at which oil and coal-fired plants completed in 1985 are equivalent investments. For example, if the average 1974 price of ∿ \$12/bbl for oil in the Northeast were to apply in 1985, the 1985 delivered price of coal would have to be below about \$22/ton for a coal-fired plant to be an economically preferable alternative. (The average 1974 coal price in the region was ∿ \$21/ton.)

A more detailed explanation of Table E-5 may be useful. For an oil-fired plant with the characteristics listed in Table E-1, the total fuel required is calculated as follows:

$$\text{Btu demand} = 1 \times 10^6 \text{ kW} \times 8760 \text{ hr/yr} \times 0.60 \times 10{,}000 \text{ Btu/kWh}$$
$$= 52.6 \times 10^{12} \text{ Btu/yr.}$$

Multiplying the Btu demand by the price of oil in $\$/10^6$ Btu (1985 prices) then gives the annual oil cost (column C).

The present worth of one year's oil costs for a 35-yr plant life, assuming that the price of oil remains constant, is given in column D. Since the present value factor for a 35-yr period at an 8% rate of return in 11.655,

Column D = Column C x 11.655.

Column E is the sum of the present values of the plant capital cost and the operation and maintenance costs:

$$(\text{Oil-fired plant}) = \underset{\text{(1985 capital cost)}}{\$502 \times 10^6} \times \underset{\text{(annual fixed charge)}}{0.1623} \times \underset{\text{(present value factor)}}{11.655}$$
$$= \$950 \times 10^6$$

$$\text{Present value of operation and maintenance costs} = \$12.3 \times 10^6 \times 11.655$$
$$= \$143 \times 10^6$$

Thus column E is $(\$950 + \$143) \times 10^6$, or $\$1093 \times 10^6$.

Column F, the total present worth of a 1000-MWe oil-fired plant to begin operation in 1985, is the sum of columns D and E.

Column G is the equivalent of column E for a coal-fired plant:

$$\text{Present value of capital cost (coal-fired plant)} = \$655 \times 10^6 \times 0.1263 \times 11.655$$
$$= \$1239 \times 10^6$$

$$\text{Present value of operation and maintenance costs} = \$44.5 \times 10^6 \times 11.655$$
$$= \$519 \times 10^6$$

The present worth of a coal-fired plant, excluding fuel costs, is $\$1758 \times 10^6$ (column G).

Subtracting column G from column F gives the break-even present worth of coal costs for equal oil and coal investment (column H).

Column I gives the 1985 price for coal (in dollars per $\$10^6$ Btu) which yields the break-even present worth (column H):

$$\text{Column I} = \frac{\text{Column H (\$/yr)}}{11.655 \times 52.6 \times 10^6 \times 10^6 \text{ Btu/yr}}$$

$$= \frac{\text{Column H}}{613.1} \text{ \$/Btu}$$

Column J is the equivalent of column I (in dollars per ton), assuming a heating value of 25 x 10^6 Btu per ton of coal.

This type of present-worth analysis can be useful in developing or analyzing energy policy alternatives for the region, particularly economic incentives or disincentives for encouraging or discouraging the use of coal as opposed to oil. Similar comparisons would apply to other fuel options. Extension of the present effort should include sensitivity analyses of all components of investment decision-making to provide additional insights for public policy analysis.

Table E-5

INVESTMENT ANALYSIS FOR COAL AND OIL-FIRED PLANTS

A Assumed 1985 Price of Oil ($/bbl)	B Equiv. 1985 Price of Oil[a] ($/10^6 Btu)	C Annual Oil Cost[c] (10^6 $)	D Present Worth Oil Cost (10^6 $)	E Present Worth Other Costs (10^6 $)	F Total Present Oil Worth (10^6 $)	G Present-Worth Coal Plant Excluding Fuel (10^6 $)	H Break-Even Present Coal Worth (10^6 $)	I Break-Even 1985 Coal Cost ($/10^6 Btu)	J Break-Even Coal Cost ($/ton)
9	1.48	78	907	1,093	2,000	1,758	242	0.39	9.75
10	1.64	86	1,005	1,093	2,098	1,758	340	0.55	13.75
11	1.81	95	1,110	1,093	2,203	1,758	445	0.73	18.25
12	1.97	104	1,208	1,093	2,301	1,758	543	0.89	22.25
13	2.14	113	1,312	1,093	2,405	1,758	647	1.06	26.50
14	2.30	121	1,410	1,093	2,503	1,758	745	1.22	30.50
15	2.46	129	1,508	1,093	2,601	1,758	843	1.37	34.25
16	2.63	138	1,612	1,093	2,705	1,758	947	1.54	38.50
17	2.75	147	1,710	1,093	2,803	1,758	1,045	1.70	42.50
18	2.96	156	1,814	1,093	2,907	1,758	1,149	1.87	46.75
19	3.12	164	1,913	1,093	3,006	1,758	1,248	2.04	51.00
20	3.28	173	2,011	1,093	3,104	1,758	1,346	2.20	55.00
21	3.45	181	2,115	1,093	3,208	1,758	1,450	2.36	59.00
22	3.61	190	2,213	1,093	3,306	1,758	1,548	2.52	63.00
23	3.77	198	2,311	1,093	3,404	1,758	1,646	2.68	67.00
24	3.94	207	2,415	1,093	3,508	1,758	1,750	2.85	71.25

[a] Assuming 145,000 Btu/gal.