CHARLES RIVER ASSOCIATES INCORPORATED

ANALYSIS OF THE ECONOMIC FEASIBILITY FOR DEVELOPMENT OF COAL RESOURCES IN THE NARRAGANSETT BASIN OF RHODE ISLAND AND MASSACHUSETTS

Prepared for

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This study assesses whether Narragansett Basin coal deposits could be developed commercially in the near future. To do this, we identify the potential market for the coal, assess the price these users would be willing to pay for Narragansett coal, and compare this price to the expected costs of producing Narragansett coal. The study concludes that the major market, New England utilities, could burn bituminous coal from Pennsylvania or West Virginia at a lower total cost than Narragansett Basin coal, assuming expected mining conditions and emission policies. Therefore, the study concludes that Narragansett Basin coal resources could not be developed economically in the next ten years.

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FOREWORD

This report was prepared by Charles River Associates Incorporated, Boston, Massachusetts under USBM Contract number J0188020. It was administered under the technical direction of the U.S. Bureau of Mines, Office of Procurement with Robert Willard acting as Technical Project Officer. A. G. Young was the contract administrator for the Bureau of Mines. This report is a summary of the work recently completed as a part of this contract during the period February 1978 to August 1978. This report was submitted by the authors in January 1979.

Chapter 1
INTRODUCTION AND SUMMARY

The Narragansett Basin of Rhode Island and Southeastern Massachusetts supported limited coal mining activity, during the nineteenth and, to a lesser extent, twentieth centuries. With the recent oil crisis and subsequent government policies directed toward a transition to coal, there has been renewed interest in the Narragansett Basin as a potential coal supply source for New England. The viability of the Basin as a coal source depends on whether the Narragansett Basin coal, sold at prices providing a reasonable return to the producer, meets a particular energy requirement at a lower cost than do alternative coal sources. If the Basin coal does, then coal deposits will be developed commercially. If not, New England coal requirements will be supplied by alternative coal sources.

Over the next ten years, the New England utilities scheduled to come on line constitute the major potential market for Narragansett coal. These utilities also have access to bituminous coals from Pennsylvania and northern West Virginia. Consequently, the maximum price that they will pay for the Narragansett coal is the price at which the total generation costs using anthracite just equal the minimum costs of generation using bituminous coals from Pennsylvania and West Virginia. If this price exceeds that which provides a sufficient return to induce development of a mine, the reserves will be developed commercially.

To assess whether the Narragansett Basin reserves are candidates for commercial development in the next ten years, we compare estimates of the price potential users would pay for anthracite with estimates of the price producers would accept. In developing these estimates, we dealt with major uncertainties. In particular, we had to take account of the fact that government policies affecting equipment requirements are not known, and that extensive information on the quality and seam characteristics of Narragansett coal is not available. Emission regulations and the quality of anthracite coal determine equipment requirements for emission control, and consequently both the cost of generating power and the price users will pay for anthracite are affected. Because the resource characteristics of the Narragansett deposits affect choice of mining technology and costs of mining, we developed a range of prices that reflect the impacts of possible emission policies and that reflect different coal quality and seam characteristics that are consistent with existing data about the Narragansett deposit.

We conclude that the Narragansett Basin reserves are not candidates for development in the next ten years. Our estimates indicate that the maximum price New England users would be willing to pay for the Narragansett coal is $25 to $37 per ton depending on the emission control policy, and that the price at which producers could supply such coal is at least $43 to $60 per ton. This represents a price difference of at least $13 to $30, under either existing emission policies or the proposed policies that require scrubbing of anthracite coal, and $6 to $23 for policies that would not require scrubbing of anthracite coal and would require scrubbing of other coals.

It is more economical to use bituminous coal plants than anthracite plants, since for most cost categories bituminous plants are less costly than anthracite units and, in those categories where anthracite is less expensive, the cost savings are not large enough to offset the costs in other categories. These cost tradeoffs are as follows.

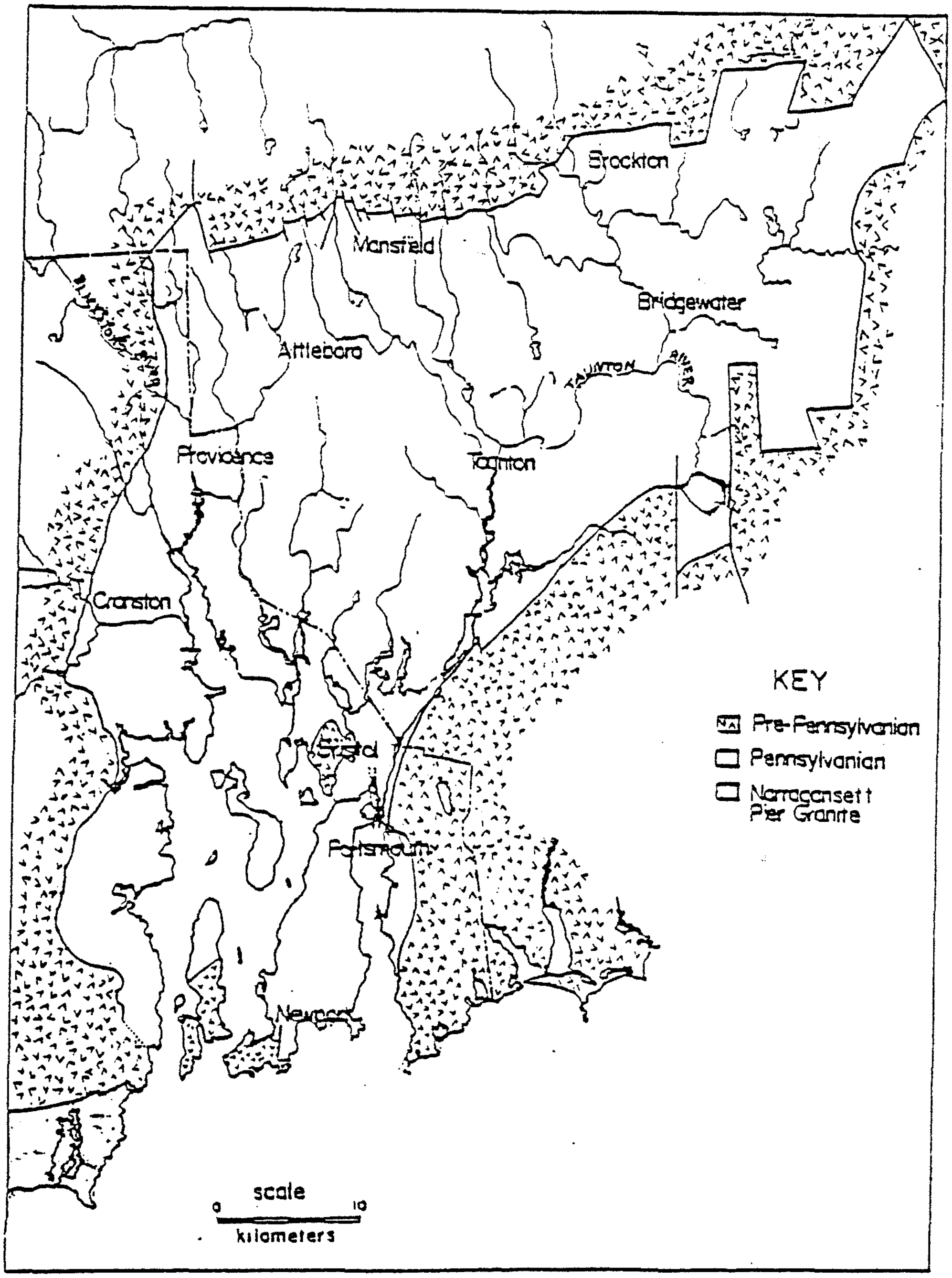
- Under both current and proposed emission regulations, there are bituminous coal units with the necessary emission control equipment with lower capital and operating costs (exclusive of coal) than there are for anthracite plants.
- Anthracite plants require 2 percent more Btu's per kilowatt hour than do bituminous plants.
- Costs of transporting bituminous coal to New England localities exceeds the cost of transporting Narragansett coal.
- Narragansett anthracite production costs are twice as large as bituminous production costs per Btu.

Because of uncertainty about the actual quality of Narragansett coal deposits and mining costs, uncertainty about cost of operating anthracite plants, and the prospects of users being tied to a few sources of supply, we feel the price differentials facing users are, at a minimum, those described above. Consequently we concluded that there would not be a market for Narragansett coal in the next ten years.

In subsequent chapters we discuss in some detail the market analyses summarized here. We begin with a definition of the market in Chapter 2. In Chapter 3, we discuss the emission policies and characteristics of the Narragansett Basin coal deposit that affect the prices consumers would pay for coal and users would accept. In Chapter 4, we estimate prices users would pay for anthracite coal, and in Chapter 5 we estimate a minimum price producers would accept for Narragansett anthracite. In this chapter, we compare these prices, concluding that the Narragansett coal deposits would not be developed commercially in the next ten years.

Figure 2–1

GEOGRAPHY OF THE NARRAGANSETT BASIN



SOURCE: Weston Observatory, Boston College, Interim Report of the Pennsylvanian Coal-Bearing Strata of the Narragansett Basin of Massachusetts and Rhode Island June 1976—December 1976. (Washington: U.S. Bureau of Mines, 1978) p. 5.

Table 2-1

UTILITY UNITS

Coal Burning	Existing Units	Locations
Merrimack I & II	Public Service of New Hampshire	N.H.
Moran II & III	Burlington Electric	Vermont
Oil Burning With Orders to Convert		
Brayton Point I, II, III	New England Power	Mass.
Mt. Tom	Holyoke Water Power	Mass.
Norwalk Harbor I & II	Northeast Utilities	Conn.
Middletown I, II & III	Northeast Utilities	Conn.
Schiller IV & V	Public Service Company of New Hampshire	N.H.

Coal Burning	Planned Units	Planned Locations
Sears Island	Central Maine Power	Searsport, Maine

Nuclear Without Construction Licenses		
Montague I & II	New England Power Exchange	Greenfield, Mass.
Pilgrim II	Boston Edison	Plymouth, Mass.
NEPCO I & II	New England Power Exchange	Charlestown, R.I.

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To convert existing bituminous or oil burning plants to an anthracite plant requires new boilers and additional space for these boilers, which makes it infeasible in some cases and uneconomic in the remaining cases to make the conversion.[1] Consequently, the planned units constitute the only potential utility market for Narragansett Coal.[2]

This potential market consists of at least the one unit, Sears Island, which is planned to burn coal. The combination of financial and environmental problems, plus the growing anti-nuclear stand of the public, may induce the utilities to change their plans regarding nuclear units. Therefore, the market could also include coal-burning units to replace up to the five planned nuclear units that do not have construction licenses. The potential market over the next 10 years, thus consists of at least one unit and up to six units, shown as planned units in Figure 2-2.

Low Coal Demand

Sears Island has not been designed yet but the expected capacity is in the 500 MW range. Therefore, we estimate annual average consumption for bituminous coal without a scrubber to be $28,909 \times 10^9$ Btu. This figure was based on a heat rate estimated by Bechtel[3] for a 500 MW unit located in the Northeast, burning West Virginia coal. (See Table 2-2.)

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[1]Discussions with personnel associated with the Public Service Company of New Hampshire, New England Power and Northeast Utilities.

[2]The scenarios evaluated in this study assume that facilities are located at currently planned sites. If one of these facilities relocated to the Narragansett Basin, to operate as a mine-mouth plant, the conclusion of this study would not change.

[3]Bechtel Power Corporation, *Coal-Fired Power Plant Capital Cost Estimates*, prepared for Electric Power Research Institute, Palo Alto, California, January 1977.

Figure 2—2

POTENTIAL COAL DEMAND

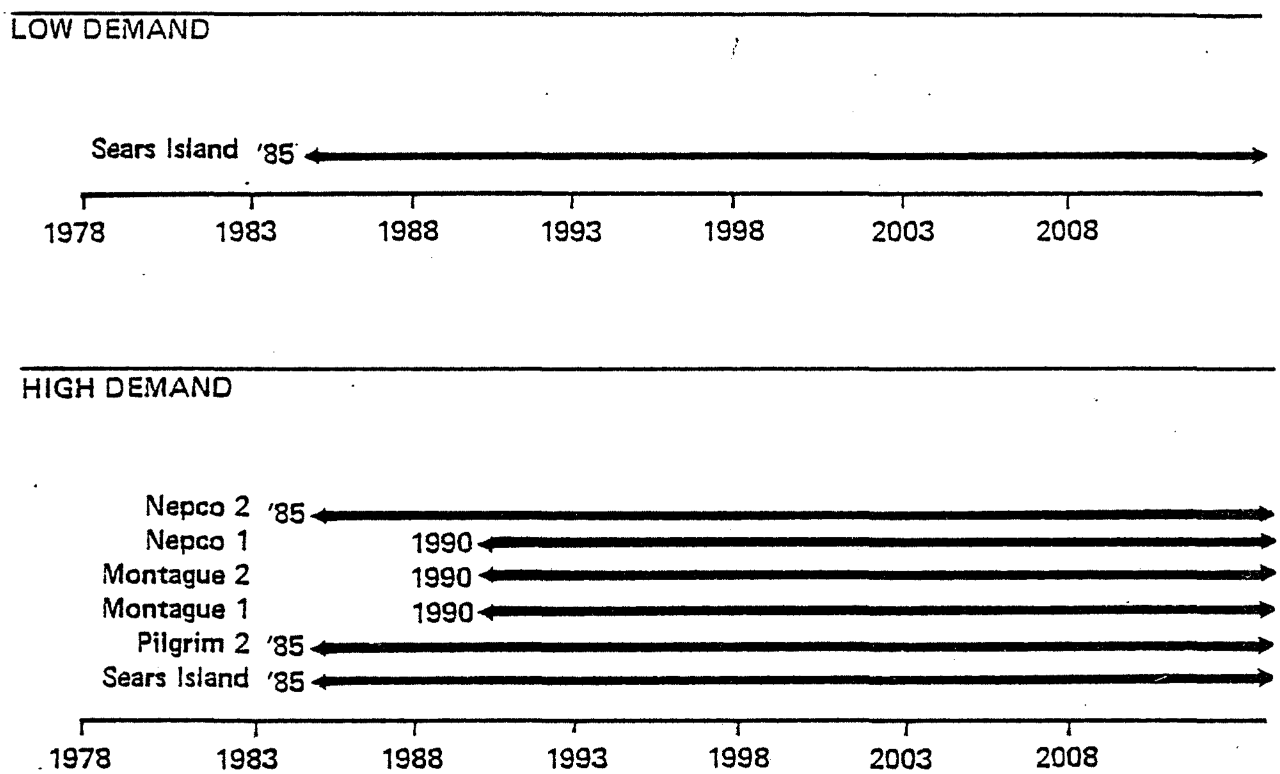

Table 2-2

PROJECTED ANNUAL COAL DEMAND BY TYPE FOR EXISTING AND PROJECTED COAL-FIRED ELECTRIC GENERATING PLANTS IN THE NEW ENGLAND AREA, 1978-2020
PLANT/UNIT

	Merrimack		Brayton Point			Mt.
Item	I	II	I	II	III	Tom
Capacity of unit after derating for coal[1] (MW)	100	314	252.3	252.3	650.3	146
Year on-line as coal[2]	1960	1968	1982	1983	1984	1982
Total life as coal[3]	35	35	23	23	23	20
Capacity Factor[4]	69.22	65.68	72	72	72	81
Heat rate[5] (Bituminous with scrubbers) (Btu/Kwh)	N.A.	N.A.	9045	9045	9045	9912
Heat rate[6] (Bituminous without scrubbers) (Btu/Kwh)	N.A.	N.A.	8672.1	8672.1	8672.1	9503.4
Heat rate[7] (Anthracite with scrubbers) (Btu/Kwh)	NA.	N.A.	N.A.	N.A.	N.A.	N.A.
Heat rate[8] (Anthracite without scrubbers) (Btu/Kwh)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Consumption[9] (Bituminous with scrubbers) (10^9/Btu/yr)	N.A.	N.A.	14,393.4	14,393.4	37,078.7	10,268.4
Consumption[10] (Bituminous without scrubbers) (10^9Btu/yr)	4882.9	15,332.4	13,800.0	13,800.0	35,569.2	9845.1
Consumption[11] (Anthracite with scrubbers) (10^9Btu/yr)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Consumption[12] (Anthracite without scrubbers) (10^9Btu/yr)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.

Table 2-2(Continued)

PROJECTED ANNUAL COAL DEMAND BY TYPE FOR EXISTING AND PROJECTED COAL-FIRED ELECTRIC GENERATING PLANTS IN THE NEW ENGLAND AREA, 1978-2020
PLANT/UNIT

	Norwalk Harbor		Middletown			Schiller	
Item	I	II	I	II	III	IV	V
Capacity of unit after derating for coal[1] (MW)	158.85	168.85	69	116	220	49	49
Year on-line as coal[2]	1982	1983	1983	1983	1983	1982	1982
Total life as coal[3]	22	22	20	20	20	14	17
Capacity Factor[4]	77	77	71	71	71	55	55
Heat rate[5] (Bituminous with scrubbers) (Btu/Kwh)	10,100	10,100	11,091	11,091	11,091	not reported	not reported
Heat rate[6] (Bituminous without scrubbers) (Btu/Kwh)	9683.6	9683.6	10,633.7	10,633.7	10,633.7	not reported	not reported
Heat rate[7] (Anthracite with scrubbers) (Btu/Kwh)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Heat rate[8] (Anthracite without scrubbers) (Btu/Kwh)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Consumption[9] (Bituminous with scrubbers) (10^9/Btu/yr)	10,821.9	11,503.2	4759.7	8001.9	15,175.9	N.A.	N.A.
Consumption[10] (Bituminous without scrubbers) (10^9Btu/yr)	10,375.7	11,028.9	4563.5	7671.9	14,550.2	2850	2850
Consumption[11] (Anthracite with scrubbers) (10^9Btu/yr)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Consumption[12] (Anthracite without scrubbers) (10^9Btu/yr)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.

Table 2-2 (Continued)

PROJECTED ANNUAL COAL DEMAND BY TYPE FOR EXISTING AND PROJECTED COAL-FIRED ELECTRIC GENERATING PLANTS IN THE NEW ENGLAND AREA, 1978-2020
PLANT/UNIT

Item	Montague I	Montague II	Pilgrim II	Nepco I	Nepco II	Sears Island
Capacity of unit after derating for coal[1] (MW)	1000	1000	1500	1000	1500	500
Year on-line as coal[2]	1990	1990	1985	1990	1985	1985
Total life as coal[3]	35	35	35	35	35	35
Capacity Factor[4]	70	70	70	70	70	70
Heat rate[5] (Bituminous with scrubbers) (Btu/Kwh)	9834	9834	9834	9834	9834	9834
Heat rate[6] (Bituminous without scrubbers) (Btu/Kwh)	9428.6	9428.6	9428.6	9428.6	9428.6	9428.6
Heat rate[7] (Anthracite with scrubbers) (Btu/Kwh)	10,030.6	10,030.6	10,030.6	10,030.6	10,030.6	10,030.6
Heat rate[8] (Anthracite without scrubbers) (Btu/Kwh)	9617.2	9617.2	9617.2	9617.2	9617.2	9617.2
Consumption[9] (Bituminous with scrubbers) (10^9/Btu/yr)	60,302.1	60,302.1	90,453.1	60,302.1	90,453.1	30,151.0
Consumption[10] (Bituminous without scrubbers) (10^9Btu/yr)	57,816.2	57,816.2	86,724.3	57,816.2	86,724.3	28,908.1
Consumption[11] (Anthracite with scrubbers) (10^9Btu/yr)	61,507.6	61,507.6	92,261.5	61,507.6	92,261.5	30,753.8
Consumption[12] (Anthracite without scrubbers) (10^9Btu/yr)	58,972.8	58,972.8	88,459.0	58,972.8	88,459.0	29,486.3

Table 2-2 (Continued)

PROJECTED ANNUAL COAL DEMAND BY TYPE FOR EXISTING AND PROJECTED COAL-FIRED ELECTRIC GENERATING PLANTS IN THE NEW ENGLAND AREA, 1978-2020
PLANT/UNIT

[1]Merrimack. Conversation with Win Robin, Public Service of New Hampshire, May 8, 1978; Brayton Point-conversation with Mr. Lucander of New England Power, May 9, 1978. From PEDCo. Environmental, Inc., *Evaluation of the Coal Conversion Potential of the Brayton Point Plant, New England Power Company*, March 29, 1977, p. iv; Mt. Tom, Norwalk Harbor, Middletown, PEDCo. Environment, Inc. *Evaluation of the Coal Conversion Potential for the Mt. Tom Plant, Northeast Utilities*. March 17, 1977, pp. iii, iv.; PEDCo. *Evaluation of the Coal Conversion Potential for the Norwalk Harbor Plant, Northeast Utilities*. March 22, 1977. pp. iii, iv.; PEDCo. *Evaluation of the Coal Conversion Potential for the Middletown Generating Station, Units 1, 2, and 3, Northeast Utilities*. March 23, 1977, pp. iii, iv.

[2]Merrimack. *Inventory of Power Plants in the United States*. Department of Energy, December 1977, p. 32; Brayton Point, Middletown. PEDCo. Environmental, Inc., *op. cit.*, p. iv ("time to conversion" as of 1977); Mt. Tom, Norwalk Harbor, Schiller. Conversation with Mr. Ramson, Department of Energy, Washington, D.C., June 6-7, 1978; Montague, Pilgrim, Nepco, Sears Island. CRA assumption based on conversations of May 8-9, 1978 with John Arnold, Central Maine Power (Sears Island) and Jim Smith, New England Power Exchange (Pilgrim, Nepco and Montague 1 and 2).

[3]Merrimack. Conversation with Win Robin, Public Service of New Hampshire., May 8, 1978; Brayton Point, Mt. Tom, Norwalk Harbor, Middletown. PEDCo. Environmental, Inc., *op. cit.* p. iv.; Schiller. Conversation with Mr. Ramson, Department of Energy, June 6-7, 1978; Montague, Pilgrim, Nepco, Sears Island. CRA assumption based on conversations of May 8-9, 1978 with John Arnold, Central Maine Power (Sears Island) and Jim Smith, New England Power Exchange (Pilgrim, Nepco, and Montague 1 and 2).

[4]Merrimack. Conversation with Win Robin, Public Service of New Hampshire, May 8, 1978; Brayton Point, Mt. Tom, Norwalk Harbor, Middletown. PEDCo. Environmental, Inc., *op. cit.* p. iv.; Schiller. Conversation with Mr. Ramson, Department of Energy, June 6-7, 1978. Montague, Pilgrim, Nepco, Sears Island. Electric Power Research Institute. *Coal-Fired Power Plant Capital Cost Estimates*. January 1977, p. 1-8.

[5]Brayton Point, Mt. Tom, Norwalk Harbor, Middletown-PEDCo. Environmental, *op. cit.* p. iv; Montague, Pilgrim, Nepco, Sears Island-assumes new plant with FGD system. Source: Electric Power Research Institute, *op. cit.* pp. 1-8.

[6]Calculated by dividing the heat rate with scrubbers by the 1.043. Source: PEDCo. Environmental, Inc., *Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers* (EPA-450/3-78-007), Feb. 1978, pp. 4-21.

[7]Memo from Mr. R. M. Dunn to Mr. J. G. Hayword, Coal Task Force Ad Hoc Energy Committee, Boston Section. IEEE, "Utilization of Narragansett Basin Anthracite," Jan. 27, 1978.
Heat rate (anthracite with scrubbers) x 1.02.

Table 2-2 (Continued)

PROJECTED ANNUAL COAL DEMAND BY TYPE FOR EXISTING AND PROJECTED COAL-FIRED ELECTRIC GENERATING PLANTS IN THE NEW ENGLAND AREA, 1978-2020

PLANT/UNIT

[8]See Footnote 7.

Heat rate (anthracite without scrubbers) = heat rate (bituminous without scrubbers) x 1.02.

[9]Brayton Point, Mt. Tom, Norwalk Harbor, Middletown, Montague, Pilgrim, Nepco, Sears Island.

Consumption = capacity of unit x .01 x average number of hours in a year (= 8760) x heat rate.

[10]Merrimack. National Coal Association, *Steam Electric Plant Factors 1977*. Table I, p. 24.

Consumption (in Btu's/yr.) = (consumption: 1000 tons) x 2000 x Btu's/lb.
Brayton Point, Mt. Tom, Norwalk Harbor, Middletown, Montague, Pilgrim, Nepco, Sears Island - see Footnote 9.

Schiller - consumption = projected annual demand for coal (from conversation with Mr. Ramson of DOE. 10-year average annual demand for coal projected to the 228,000 tons) x heat value of coal (=25 x 10^6 BTU/ton: from CRA EPRI coal model). The consumption was then divided between units I and 2 by capacity.

[11]Memo from Mr. R. M. Dunn to Mr. J. G. Hayword, Coal Task Force Ad Hoc Energy Committee, Boston Section. IEEE, "Utilization of Narragansett Basin Anthracite," January 27, 1978.

Consumption (anthracite) = 1.02 x consumption (bituminous).

[12]See Footnote 11.

SOURCE: Data were calculated by Charles River Associates Incorporated, based on information obtained from sources cited in footnotes 1-12 above.

Sear's Island's bituminous coal consumption will increase to 30,151 x 10^9 Btus when a scrubber is added. The consumption increases because more coal generation is needed to operate the scrubbers. Consequently, the net heat rate will increase as it will take more Btu per Kwh to generate an adequate supply of electricity to the system.[1] PEDCo estimates that plants suffer a 4.3 percent energy penalty when they install scrubbers[2] and that is the figure we used to calculate additional consumption due to scrubbers.

If anthracite coal is used rather than bituminous coal, the Btus of fuel required per kilowatt hour increases because of different characteristics of an anthracite boiler, in particular the longer furnace residence time required for complete burnout.[3] To calculate anthracite demand we added 2 percent to the bituminous coal heat rate.[4] The new heat rate for these possible candidates under the anthracite scenario is 9618 Btu per kwh if the units do not use scrubbers or 10,031 Btu per Kwh if they do use scrubbers. Annual anthracite consumption for one 500 MW unit with scrubbers will be 30,754 x 10^9 Btu and 29,486 x 10^9 Btu without scrubbers (see Table 2-2).

High Coal Demand

The high coal demand scenario incorporates the unit included in the low demand scenario plus the five planned nuclear units, for three utilities.

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[1]PEDCo. Environmental, Inc., *Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers*, prepared for U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1978.

[2]*Ibid.*

[3]Memo from R. M. Dunn to J. G. Hayward, "Utilization of Narragansett Basin Anthracite," January 27, 1978, from Coal Task Force ad hoc Energy Committee, Boston Section, IEEE.

[4]*Ibid.*

The five nuclear units planned for New England are all being designed as 1150 MW units with start up dates between 1985 and 1990. For our high demand scenario we have grouped the units by start-up date and have adjusted their capacities so that the total on-line capacity by 1990 approximates New England Power Exchange's estimated needed additional capacity for the region of 5750 MW. In our scenario NEPCO 1 and Pilgrim 2 will be operating by 1985 and Montague 1 and 2 and NEPCO 2 are slated for operating in 1990. We assumed five units either have two or three 500 coal burning MW units on their sites to replace the 1150 MW reactors.

Total capacity by 1990 for these five units will be 6000 MW. See Table 2-2. Using Bechtel's estimated heat rate of 9834 Btu per Kwh with scrubbers and its estimated 70 percent capacity factor, annual bituminous coal consumption varies between 346,897 x 10^9 Btu and 361,813 x 10^9 Btu depending on whether or not scrubbers are used (see Table 2-2).

In this scenario the peak year for coal consumption is 1990, five years after the low demand peak. In 1990, maximum bituminous coal demand with scrubbers will be 391,964 x 10^9 Btu (based on data in Table 2-2).

Summary

Under both the low and high coal scenarios, demand for coal for planned units does not begin until 1985 and is all on-line by 1990. Btu requirements in 1985 are estimated at a maximum of 30,151 x 10^9 Btu for Sears Island and increase to 391,964 x 10^9 Btu in 1990 when the NEPCO, Pilgrim and Montague plants come on-line. If anthracite coal is used, the Btu requirements will increase to a maximum of 399,800 x 10^9 Btu to account for the lower efficiency of an anthracite boiler.[1]

[1]The amount of coal tonnage required depends on the Btu content of the coal delivered, which can differ significantly due to variation in Btu content of raw coal and variation in washing characteristics.

Coal Supply Sources

The alternative fuel for these coal burning plants is bituminous coal, which is used in the existing coal burning plants. Presently, Merrimack 1 and 2 of the Public Service Company of New Hampshire uses 1.81-2.34 percent sulfur bituminous coal[1] from Loveridge Mine, Marion County, West Virginia and Moran 2 and 3 of Burlington Electric used 1.7 percent sulfur bituminous coal from Harmon-Matthews Mine in Armstrong County, Pennsylvania. However, the Moran units are being converted to wood burning over the next two years and have not purchased any coal since the end of 1977.[2]

The closest supply sources of bituminous steam coal are Pennsylvania, West Virginia and Kentucky. While Pennsylvania has some low sulfur coal, the largest deposits are in Southern West Virginia and Kentucky. Consequently, for the purposes of comparative analysis, we selected a high sulfur coal shipped from Altoona, Pennsylvania and a low sulfur coal shipped from Maidsville, West Virginia, described in Table 2-3.

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[1]Conversation with Mr. Gakner, Federal Power Commission, August 3, 1978. He reported that the Public Service Company reported two different sulfur contents: 1.81 percent in April 1978 and 2.34 percent in December 1977.

[2]Conversation with Mr. Gakner, Federal Power Commission, August 3, 1978.

Table 2-3

1985 BITUMINOUS COAL SUPPLY ALTERNATIVES

	Btu/Lb.	Lb. SO_2/ 10^6Btu	Lb. Ash/ 10^6 Btu
High Sulfur: Pennsylvania, Northern West Virginia	12,076	3.72	.102
Low Sulfur: Southern West Virginia, Kentucky	12,536	1.13	.089

SOURCE: Federal Power Commission, *Cost and Quality of Electric Utility Plant Fuels*, 1976.

Coal Market Definition Summary

Major potential users of anthracite coal that currently have plans for new units are New England utilities. At least one utility, Central Maine Power and potentially two others, New England Power Exchange and Boston Edison will have coal-burning units. Both low sulfur coal and high sulfur bituminous coal are available as alternative sources of fuel for these units. These sources are located in Pennsylvania, West Virginia and Kentucky. To evaluate the potential market for Narragansett anthracite, we use these potential demand points and supply sources to determine if the utilities can generate power at lower costs with anthracite coal than with these alternative bituminous coals.

Chapter 3
COAL MARKET ANALYSES-SCENARIOS

The exact value of demand and supply prices for Narragansett anthracite over the next ten-year period cannot be predicted with certainty. Government policies that affect these prices are not known and extensive information on Narragansett Basin coal reserves is not available. The demand price, the maximum price a buyer will pay per Btu of anthracite coal, given the alternative coal sources available to him, depends on the emission regulations and the coal quality. The demand price is such that the cost of generating power with anthracite fuel just equals the cost of generating power with the next best alternative coal source, which in New England is bituminous coal from Pennsylvania and West Virginia. The supply price, a price sufficient to induce a commercial coal producer to open a mine, depends on the geological characteristics of the coal deposit.

In particular, the emission regulations and qualities of coal burned determine equipment requirements for emission control and consequently, the cost of generating electricity. These equipment requirements for combustion and emission control are major determinants of the different costs of generation by anthracite and bituminous plants and hence the demand price for anthracite. Seam characteristics affect the technology choice and cost of mining while coal quality determines Btu content of the coal. Consequently, anthracite seam characteristics and coal quality are major determinants of the supply price of coal.

To evaluate the potential effect on price of the uncertainties about emission regulations, coal qualities and seam characteristics, we develop a set of assumptions about each of these. These assumptions are based on information about both existing conditions and expected conditions. In this section we describe these assumptions which are used to define scenarios for developing estimates of the supply and demand price.

Emission Regulations

While future emission policies are not certain, current policies and proposed legislation provide a range of possible alternatives. Current regulations limit sulfur emissions to no more than 1.2 pounds of sulfur dioxide per million Btu's at the stack. They also limit particulate emissions to no more than .05 pounds per million Btu's or in some cases .1 pounds if the equipment is designed to also reduce sulfur dioxide emissions. Proposed emission regulations[1] require 90 percent removal of sulfur and limits particulate emissions to .03 pounds per

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[1]Environmental Protection Agency, "Standards of Performance for New Stationary Sources, Electric Utility Generating Units," Draft Proposal, November 1977.

million Btu at the stack. These proposed regulations are usually interpreted as requiring a desulfurization unit and particulate control unit for all coal. The proposed sulfur dioxide emissions have, in addition, a floor of .2 pounds of sulfur dioxide per million Btu's and a ceiling of 1.2 pounds of sulfur dioxide per million Btu's. The cleaning process must reduce emissions to the ceiling level and need not reduce emissions below the floor. The ceiling prohibits use of coal which when cleaned still emits more than 1.2 pounds of sulfur dioxide per million Btu's. The floor is so low that while emission costs could be reduced for relatively low sulfur coals or possibly eliminated, almost all coals must be cleaned.

These regulations result in different tradeoffs among coal types. Under existing regulations, coal buyers could burn a range of low sulfur coals without using a scrubber. Under proposed regulations, a scrubber is required for most low sulfur coals. Consequently, the economic tradeoffs between two coals, with significantly different sulfur content, will differ under the various scenarios.

We expect that the actual regulation in effect over the 10-year period of interest will be some variant of the proposed policy. The degree of cleaning may be decreased and the floor may be increased to allow more low sulfur coals to be burned without scrubbers or to be cleaned at lower cost. Since these assumptions can affect the price buyers are willing to pay for anthracite coal, we define three scenarios: NSPS, BACT, BACT/Variance. Table 3-1 summarizes the assumptions on particulate and sulfur dioxide control for NSPS and BACT. In the BACT/Variance scenario, all anthracite coal is exempted from desulfurization requirements.

Table 3-1

EMISSION REGULATIONS

	NSPS		BACT[1]	
	Sulfur lbs. $SO_2/10^6$ Btu	Particulate lbs./10^6 Btu	Sulfur lbs. $SO_2/10^6$ Btu	Particulate lbs./10^6 Btu
Planned Coal-Burning Units				
Central Maine Power (Maine)			Floor .2, Ceiling 1.2	
Sears Island	1.2	.10	90 percent removal	.03
Planned Nuclear Units				
Pilgrim 2	1.2	.05-.10[1]	same as above	.03
NEPCO 1	1.2	.10	same as above	.03
NEPCO 2	1.2	.10	same as above	.03
Montague 1	1.2	.05-.10[1]	same as above	.03
Montague 2	1.2	.05-.10[1]	same as above	.03

[1]Emission rate of .10 pounds/10^6 Btu allowed if equipment is designed to also reduce SO_2.

Coal Quality

As indicated earlier, both demand and supply prices for anthracite coal depend on the quality of the anthracite coal and the quality of the bituminous coal used as an alternative. In particular, the cost of control to meet sulfur dioxide and particulate emission regulations depends upon the sulfur and ash content of coal. The Btu content of delivered coal determines the quantity of coal required and, in addition, when combined with the production cost (extraction and mine-mouth coal preparation), determines its price per million Btu.

To estimate the demand and supply price of anthracite coal, we develop definitions of the Btu, ash and sulfur content of cleaned coal for use in different scenarios. For bituminous coal, we use the average quality of coals delivered to utilities from each region of interest. For Narragansett anthracite coal, we develop definitions using available data about the quality and washability of samples taken from core drillings. These Btu, ash and sulfur definitions are shown in Table 3-2. As noted, the quality estimates for bituminous coal are based on Federal Power Commission data. The quality estimates for anthracite coal are developed in this section.

In developing the coal quality definitions, it is important to distinguish between coal as received from the mine and coal released from a preparation plant. If the percent of ash and rock in coal as received from the mine is sufficiently high, then, at a minimum, coarse cleaning is used to remove this material, decreasing the volume of coal per Btu. This reduces transportation costs and waste disposal costs at the plant. In addition, more intense cleaning is sometimes necessary to reduce ash to a level that can be processed by the boiler and particulate control unit.

Table 3-2

COAL QUALITY SCENARIOS

	Btu/lb.	lb. SO_2/ 10^6 Btu	lb. Ash/ 10^6 Btu
Bituminous Coal[1]			
High Sulfur (PA., N WVA.)	12,076	3.72	.103
Low Sulfur (S WVA, KY)	12,536	1.13	.089
Narragansett Anthracite[2]			
Low Sulfur	11,250	.40	6.2
Very Low Sulfur	11,250	.08	6.2

[1]All values are based on the average quality of coal from these regions delivered to electric utilities. The average quality data are taken from Federal Power Commission, *Cost and Quality of Electric Utility Plant Fuels*, 1976.

[2]These values are consistent with the highest quality of Narragansett coal samples analyzed. The basis for selecting these estimates is given in the text.

A coal preparation plant takes raw coal, grinds it up, separates the coal from the ash and other materials (generally by floating the mixture in a dense liquid so that the coal will float and the ash will sink), and then dries the coal. Consequently, the tons of prepared coal are a portion of the tons of raw coal entering the plant. The prepared coal will have a lower ash content and, to the extent that sulfur in the raw coal was in the ash as is the case with Pyritic sulfur, the coal will have a lower sulfur content as well. The Btu content of a ton of prepared coal will be greater than that of raw coal as a result of the separation of ash and other materials.

The degree of cleaning desired and the resulting yield, sulfur, ash and Btu content, depends on the nature of the raw coal and the density of separation used in the preparation process. For bituminous coal, the typical separation density is 1.4 to 1.6. Any object with a specific gravity of less than that of the medium will float, while objects with greater specific gravities will sink. If the density of separation is lowered, the recovery or yield will go down because more of the raw coal will sink, but the Btu value of the prepared coal will increase because its ash content will be lower.

Anthracite has a greater density than bituminous coal, which presents some problems in coal washing. First, more dense and possibly different separation mediums are needed. Second, for a given density of ash, the range of densities between the ash and the coal will be less, which makes their separation more difficult. Anthracite has been prepared at high separation densities (2.2) in Europe and, in the past, output of the Cranston mine in the Narragansett Basin was cleaned (as reported in Ashley's Survey Bulletin 615 in 1915). What is not known is whether these high separation processes are economical in the United States today.

In developing coal quality scenarios, it is necessary to identify the expected quality of the raw coal, evaluate the necessity for cleaning, and, if cleaned, assess the quality of cleaned coal. In this analysis, we used available data on depths and seam thickness from 15 core drillings[1] in the Narragansett Basin and chemical analyses and washability data from five of these core drillings.[2]

The principal source of data on the quality of raw coal is chemical analyses of samples from the five core drillings. Four of these samples, shown in Table 3-3, are from sources of sufficient thickness for mining. The fifth sample, from West Mansfield, was both too thin (15.5 inches) and too deep (975 feet) to be minable. Chemical analyses on the West Mansfield sample indicated a high sulfur coal with other characteristics similar to the Bristol and Somerset sample with 17.4 percent ash, .14 percent sulfur and 11,215 Btu per pound.

Because of the disturbed nature of deposits, we assume all run of mine (ROM) coal requires at least coarse cleaning to remove rock rock and shale partings.[3] For high-quality run of mine coal, such as Somerset-Bristol, we assume this level of cleaning is sufficient. For low-quality run of mine coal, such as the Portsmouth sample, a greater degree of cleaning may be desired to improve the coal quality. This greater degree of coal cleaning requires higher costs.

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[1]Received from Weston Observatory as an updated log of core drilling.

[2]William R. Barton, James W. Skehan, Albert W. Deurbrouck, and Daniel P. Murray, "Anthracite in the Narragansett Basin of Rhode Island and Massachusetts," Bureau of Mines Information Circular IC 8760, 1977.

[3]Based on a report of and discussions with Charles Manula (see Appendix A).

Table 3-3

ANTHRACITE RAW COAL QUALITY

	Raw Coal Samples (unwashed)		
	Ash (percent)	Sulfur (percent)	Btu's per pound (as received)
Mansfield	48.6	.58	6630
Somerset	12.7	.10	10669
Bristol	13.6	.00	10944
Portsmouth	27.5	.29	6970

SOURCE: Bureau of Mines, Anthracite in the Narragansett Basin of Rhode Island and Massachusetts, BOM Circular 8760, 1977.

To develop a scenario for cleaned coal, we use washability data for core samples from the Mansfield and Somerset areas in Massachusetts and the Bristol and Portsmouth areas of Rhode Island. All these samples were obtained from seams of coal that were of sufficient thickness to be mined. The average characteristics of the washed coal are summarized in Table 3-4.

The quality of the Portsmouth and Bristol samples is sufficiently high that only coarse washing appears necessary. After coarse washing the quality of this coal should be in the mid-range of the two levels of cleaning in Table 3-4. The ash content of these two samples compares favorably with anthracite burned by power plants in Pennsylvania. These samples represent the highest quality coal found among all the drillings, and are used in developing the scenarios, as examples of coal requiring only coarse cleaning. On the other hand, the Portsmouth coal represents a coal that requires more intensive cleaning.

The average results of the washability tests shown in Table 3-4, are results of laboratory analyses and not output of an actual preparation plant so the statistics are on a moisture-free basis. In fact, cleaned anthracite burned by power plants in Pennsylvania has a moisture content of 10 percent. Btu values of the prepared coal will be at least 10 percent lower once they are corrected for moisture content.

For high quality coal such as the Somerset and Bristol, a coal with a quality midway between the two cleaning separation densities is described in Table 3-4. The coarse cleaned

Table 3-4

ANTHRACITE WASHED COAL QUALITY

	Washed							
	Density of Separation 2.0				Density of Separation 2.4			
	Yield (percent)	Ash (percent)	Sulfur (percent)	Btu's/lb.[1]	Yield (percent)	Ash (percent)	Sulfur (percent)	Btu's/lb.
Mansfield	35.4	21.0	.47	11287	--	--	--	--[2]
Somerset	43.7	5.7	.12	12691	90.6	8.9	.08	12254
Bristol	9.6	1.3	.01	13147	88.6	4.8	.00	12701
Portsmouth	69.7	10.7	.24	12223	--	--	--	--[2]

[1]Moisture free.

[2]Not reported.

SOURCE: Bureau of Mines, "Anthracite in the Narragansett Basin of Rhode Island and Massachusetts," BOM Circular 8760.

coal would be 5.3 percent ash, .05 percent sulfur, and have 12,700 Btu's per pound (moisture-free). The Mansfield coal is of such low quality that its use is unlikely. The Portsmouth coal sample has 27.5 percent ash, 29 percent sulfur, and a Btu content of 6970 Btu's per pound raw and 10.7 percent ash, 24 percent sulfur, and 12,223 Btu's per pound when washed at a separation density of 2.0.

The qualities of these two coal types in terms of emission of ash, sulfur dioxide and the likely Btu content (with moisture) are shown in Table 3-5. Both the coal types have little ash and sulfur content and relatively high Btu content. However, the difference in sulfur is sufficient to require desulfurization in one case and not in the other for some emission policies.

Since the sulfur content of the raw coal samples varies substantially, it is not certain whether all coal will require scrubbers under proposed policies.

Therefore, we define two coal-type scenarios. The coal has ash and Btu content equal to the average of the Somerset, Bristol and Portsmouth samples. This corresponds to 7 percent ash and 11,250 Btu's per pound (with moisture). However, one coal has .05 percent sulfur and the other .24 percent or equivalent emissions of .08 and .40 pounds of sulfur dioxide per 10^6 Btu's respectively. We estimate that the total yield for these coal prototypes after removal of ash, rock and shale partings will range from 50 to 70 percent, and in the estimation of supply prices in later chapters we use 70 percent.

Table 3-5
EXPECTED ANTHRACITE CLEANED COAL QUALITIES

	Btu/lb. (with moisture)	Lb $SO_2/10^6$ Btu	Lb Ash/10^6 Btu
Somerset - Bristol (very low sulfur)	11,470	.08	4.6
Portsmouth (low sulfur)	11,001	.41	9.7

$$\text{lb}/10^6\ \text{Btu} = \frac{(\text{percent sulfur}) \times 2 \times .95 \times 10^6}{\text{Btu/lb}}$$

Seam Characteristics

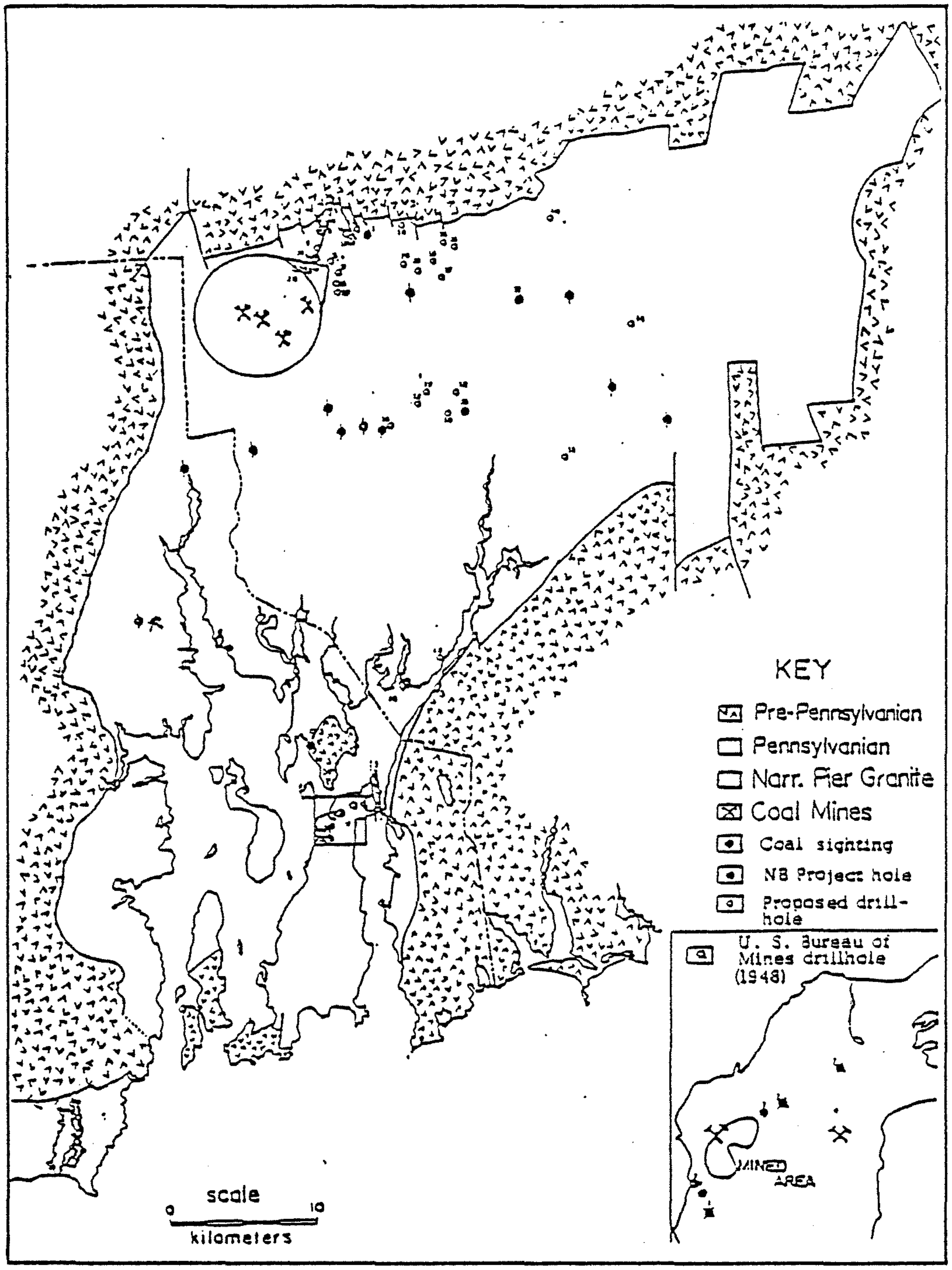
To make a precise estimate of coal extraction costs, a mining engineer uses detailed cross sections of the deposit under consideration. Cross sections are underground maps tracking a deposit's depth and thickness and the geological characteristics of it. These cross sections define important factors that affect the choice of mining technology and cost of extraction including seam depth, seam thickness, seam dip (angle of inclination), stripping ratio (function of depth, thickness and density), continuity of the deposit, roof conditions, gassiness and water conditions.

The depth of the deposit is an important determinant of mining method. Deposits deeper than 200 feet are candidates for underground mining and less than 400 feet are candidates for surface mining. The seam size is an important determinant of the economics of many conventional underground mining methods: the thicker the seam, the less expensive the cost of extraction. The overburden ratio is an important determinant of the feasibility and economics of surface mining. Surface mines generally must have an overburden ratio of less than 20:1; the smaller the overburden ratio, the lower the cost of extraction. Seam dip is another important determinant of mining method. Underground mining of seams with dip greater than 14°, cannot be carried out with conventional underground methods; instead techniques such as breast mining or augur mining are necessary.

Other important factors are the continuity and extent of the deposit. Continuity refers to the constancy of the seam thickness, i.e., the degree to which it remains a constant thickness throughout the deposit. Deposits that are not continuous can end abruptly. Discontinuity affects costs

Figure 3—1

COAL SIGHTINGS AND DRILL HOLES OF
THE NARRAGANSETT BASIN



SOURCE: Weston Observatory, Boston College, Interim Report of the Pennsylvanian Coal-Bearing Strata of the Narragansett Basin of Massachusetts and Rhode Island June 1976—December 1976, (Washington: U.S. Bureau of Mines, 1978) p. 6.

adversely because a seam of variable thickness cannot be mined with low-cost mechanized techniques and when a deposit ends abruptly the total output over the life time of the mine is reduced and the average fixed costs are correspondingly higher. Gas and water require special control equipment. Roof conditions affect the feasibility of certain conventional underground mining conditions.

Knowledge of Resource Characteristics

Sufficient information to describe detailed cross sections of actual deposits, for use in a detailed engineering cost study, are not available for any area of the Basin. However, the existing core drilling data provides information on seam depth, thickness, dip and stripping ratio at each drill site. While this drilling information is not sufficient to define these characteristics for a detailed cross section at any site and not extensive enough to represent all sites in the Narragansett area, the test drilling results viewed as a whole do provide a basis for developing likely scenarios.

In this section, we develop assumptions about seam depth, thickness, dip and stripping ratio based on the sample core drilling data. Our source of seam dip data is Table 5 of a mimeographed report prepared at Weston Observatory, Narragansett Basin Project, March 1978. Our source of seam depth and thickness data is a core log summary that updates Table 1 of the Interim Report.[1] While the core drilling data identified approximately 86 seams, shown in Figure 3-1,

[1]Weston Observatory, Boston College, "Interim Report of the Pennsylvanian Coal-Bearing Strata of the Narragansett Basin of Massachusetts and Rhode Island June 1976 - December 1976," prepared for the U.S. Bureau of Mines, June 1978.

most were too thin to be mined. For this reason we have restricted our analysis to the nine seams that are over four feet thick (true thickness) presented in Table 3-6. These nine seams are typical of the other seams with regard to depth. About half of the thinner seams were deeper than the average depth of the nine seams of minable thickness. The thickness, dip, depth, stripping ratio and continuity represented by this data are summarized in Table 3-7.

Dip ranges from 22° to 50° with a median of 36°. In underground mining different technologies are used to mine seams with different dips. From 0 to 14° conventional pillar methods are often used, for seams greater than 14° some form of breast mining is used. As discussed in Appendix B, costs of breast mining do not vary significantly with changes in dip. Since all sources in the sample have dip greater than 20°, we assume breast mining technology for underground mines. For surface mining, costs also vary little with dip other than the effect of dip on strip ratio. Consequently the cost of both underground and strip is developed assuming a dip of greater than 20°.

The depths of the potentially minable seams range from 118 to 734 feet with a median of 385 feet. Deposits deeper than 200 feet are candidates for deep mining techniques. The median depth of seams deeper than 200 feet is 463 feet. For underground mining, variances in depth of 200 feet will affect costs about 13 percent. To develop cost estimates, we assume a depth of 463 feet for our base case.

For surface mining, the depth of the deposit affects costs through its impacts on the stripping ratio. The only assumption we make about depth of deposits for surface mining is that they are less than 400 feet.

Table 3-6

CORE SAMPLES

SEAMS WITH A TRUE THICKNESS GREATER THAN FOUR FEET

Hole	Seam	Dip	Depth	Measured Thickness	True Thickness[1]	Strip Ratio[2]
1	13-G	31°	497	5.5	4.7	
2	4-C	36°	258	8.9	7.2	23.1
6	2-B	50°	385	17.5	11.2	22.9
7	1-A	22°	230	31	28.7	4.8
14	3-B	43°	156	6	4.4	23.6
23	1-A	45°	463	5.9	4.2	
33	2-B	27°	734	11	9.8	
51	1	40°	118	7	5.4	14.
64	3-B	30°	626	4.7	4.1	

[1]True thickness = (cosine of dip angle) X (measured thickness)

[2]Strip ratio = [(depth - true thickness)/(true thickness)] X .6859

SOURCES: Updated with log summary provided by Weston Observatory, Boston College.

Weston Observatory, Boston College, "Interim Report of the Pennsylvanian Coal-Bearing Strata of the Narragansett Basin of Massachusetts and Rhode Island June 1976 - December 1976." Prepared for Bureau of Mines, June 1978.

Table 3-7

RESOURCE CHARACTERISTICS

	Range	Median
Thickness (9 out of 86 seams)[1]	4-28 feet	5.4 feet
Depth (9 seams)	118-734 feet	385 feet
Dip (9 seams)	22-50°	36°
Stripping Ratio (5 out of 9 seams)[2]	4.8-23.9	22.9
Continuity (1 case)	None found	No units

[1]Measured Thickness adjusted for dip.

[2]Seams with depth less than 400 feet.

SOURCE: Weston Observatory, "Interim Report of the Pennsylvanian Coal Bearing Strata of the Narragansett Basin of Massachusetts and Rhode Island, June 1976 - December 1976." Prepared for Bureau of Mines, June 1978. Boston College, Mass., December 1976.

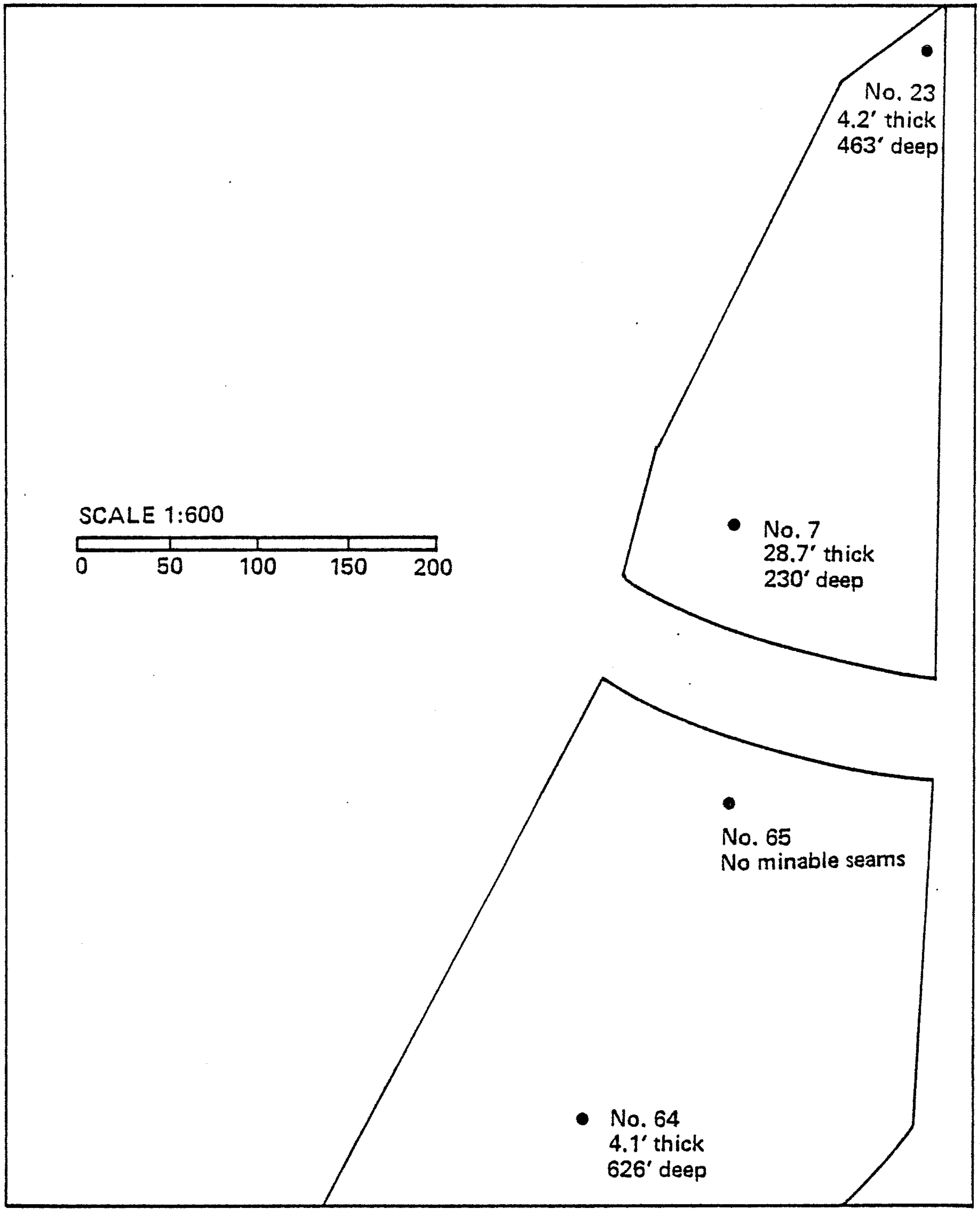
The key determinant of surface mining costs is the cubic yards of overburden that must be removed per ton of clean coal recovered. It depends on the ratio of depth to seam thickness times a constant term. The constant term depends on the density of the coal and the recovery factor. We assume that the anthracite will have a density of 120 pounds per cubic foot and the recovery factor will be 90 percent. In Table 3-6, we present the stripping ratios for those deposits less than 400 feet deep. The range of stripping ratios observed is large. The three highest ratios may be too extreme to be minable with surface mining techniques. The low ratio is extremely low and does not represent a minable deposit for reasons that will be discussed. We base our assumed ratio on the four remaining observations; we assume a high ratio of 20 and a low ratio of 15.

The thickness of the potentially minable seams identified in the core drilling data, presented in Table 3-6, range from a low of 4.1 to a high of 28.7 feet. Seams less than 4 feet thick were excluded from the table. The average thickness is 5.4 feet. As indicated earlier, variations in seam thickness does not have a significant effect on the underground breastmining technologies used to mine seams with significant dips. For surface mining the effects of various thicknesses is reflected in the stripping ratio. However, the thickness of the seam is an important determinant of the size of the reserves required to support a mine. To estimate reserves, we use a seam thickness of 5.4 feet.

An additional geological characteristic of a coal deposit that affects cost is the degree of continuity. This information cannot be determined from a single core sample but can be inferred from many samples at a particular site. An example of discontinuous deposits is illustrated in Figure 3-2. The

Figure 3–2

PACE AND COMPASS MAP
BRISTOL, RHODE ISLAND DRILLSITES



map shows four core drill sites in the town of Bristol, Rhode Island. Site No. 7 is the extremely thick seam with the extremely low stripping ratio. Drilling site No. 65, only 165 feet away, found no seams thicker than .6 feet. At drilling site No. 23, 280 feet in the other direction, the only seam of minable thickness was 4.2 feet thick at a depth of 463 feet. The deposit located at site No. 7 cannot be very large. For this reason, we expect that the coal seams in the Narragansett Basin are not generally continuous. This assumption is based on mining histories, discussions with consultants[1] and members of the Observatory staff. However, because there is only this one sample, we assume continuous deposits for our costing scenario, since this provides a lower boundary on costs of extraction for anthracite mining.

Seam Characteristic Scenarios

In developing scenarios for costing, we have developed a set of conditions that reflect the best mining conditions, consistent with the core drill data. We assume that the continuity is good and that the dip exceeds 20°, requiring breast mining underground and open pit surface mining. The actual dip used in the costing scenarios, shown in Table 3-8, is selected to provide a low-cost estimate for deposits with dips in this range. Values of thickness, depth and stripping ratio, shown in Table 3-8, were selected for the underground and surface mining scenarios.

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[1]Resource Engineering Inc. and Charles Manula reviewed the basin information.

Table 3-8

SEAM CHARACTERISTIC SCENARIOS

Underground Mining - Breast		Base Case	Range
	Thickness	5.4 feet	
	Depth	463 feet	263-663
	Dip	20^0	None
	Continuity	Good[1]	

Surface Mining - Open Pit		Base Case	Range
	Thickness	5.4 feet	None
	Depth	< 400 feet	
	Stripping Ratio		15:1;20:1
	Continuity	Good[1]	

[1] It is quite possible that the deposit's continuity is not good. However because of extreme uncertainty we make the assumption that gives lower mining cost.

Chapter 4
DEMAND PRICE FOR NARRAGANSETT ANTHRACITE COAL

To assess the likely range of demand prices, we evaluate demand prices for scenarios that represent the three emission regulations, two bituminous and two anthracite coal quality types, described in Chapter 3. The emission regulations, identified as NSPS, BACT, BACT/Variance, represent continuing existing standards, proposed new standards (1977), and proposed new standards with a variance to allow the use of anthracite coal without scrubbers. The anthracite coal types include a low sulfur coal that emits less than 1.2 pounds of sulfur dioxide (SO_2) per million Btu and a very low sulfur coal that emits less than .2 pounds of SO_2 per million Btu. The bituminous coal types include a low sulfur coal that emits less than 1.2 pounds SO_2 per million Btu and a high sulfur coal that emits more than 1.2 pounds of SO_2 per million Btu.

The maximum price that a coal-burning utility will pay for anthracite coal is the price at which the total cost of generating electricity with Naragansett anthracite coal just equals the total cost of generating electricity with other coals. In this case, the present value of the costs of generating the electricity under these two alternatives is just equal. The net present value, shown in Table 4-1, is the discounted stream of capital equipment costs and operating costs (excluding fuel costs), mine-mouth coal prices and coal transport costs. When all costs except anthracite prices are known, the equation in Table 4-1 can be used to derive the maximum price a utility would pay for anthracite coal.

No matter which combination of assumptions is chosen, the environmental regulations are such that both a bituminous and an anthracite unit would have to install particulate removal equipment. A bituminous coal-burning unit would usually use an electrostatic precipitator (ESP) under New Source Performance Standards while a fabric filter is expected to be more cost-effective for removing ash in an anthracite plant. Fabric filters have lower projected capital plus operating costs than electrostatic precipitators burning low sulfur coal.[1]

Actual costs may differ from projected costs because there has not been much experience operating fabric filters for utility boilers. However, since we assume fabric filters will be used for anthracite particulate control, we also assume they will be used for low sulfur bituminous control, so that we have a consistent basis of comparison.

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[1]PEDCo. Environmental, Inc., *Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers*, prepared for U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1978.

Table 4-1

NET PRESENT VALUE GENERATION COSTS

$$NPV_{1985} = K_{1985} + \sum_{y=1985}^{2019} \left[\left(\frac{1+e_o}{1+d} \right)^{y-1985} O_y + \left(\frac{1+e_f}{1+d} \right)^{y-1985} F_y + \left(\frac{1+e_t}{1+d} \right)^{y-1985} T_y \right]$$

where $NPV \equiv$ Net Present Value

$K_y \equiv$ Capital costs in year y

$O_y \equiv$ Operating costs in year y

$F_y \equiv$ Fuel costs (minemouth) in year y

$T_y \equiv$ Fuel transport costs in year y

$d \equiv$ Discount rate

$e_o \equiv$ Real escalation in operating costs

$e_f \equiv$ Real escalation in minemouth prices

$e_t \equiv$ Real escalation in transport rates

Under presently existing new source emission regulations, sulfur control equipment does not always have to be installed. This depends on the applicable federal or local regulations and the sulfur level in the coal. The anthracite coal types specified in the scenario do not require flue gas desulfurization units to meet the existing new source performance standards. Under the revised standards, the low sulfur coal might not.[1] Under the BACT/Variance regulation, the use of a flue gas desulfurization unit is waived for all anthracite coal types. For the existing standards, low sulfur Eastern bituminous coal does not require desulfurization and high sulfur Eastern coal does. With either BACT regulation, a scrubber is required for both bituminous coal types.

These assumptions about alternative emission policies and sulfur types result in four demand scenarios, which we designate as NSPS, BACT-L, BACT-VL, and BACT/Variance. The emission control equipment and anthracite coal quality used to evaluate demand prices under these scenarios are presented in Table 4-2. For each scenario, two possible bituminous coal supply sources are considered.

The demand price depends on both the emission regulation and the quality of both the anthracite and bituminous coals, which determine the choice of emission control equipment and the amount of coal required. To see this, note that the estimated demand price, as shown in Table 4-3, equals the sum of the alternative coals' cost and the differential capital cost, operating cost (excluding coal costs) and coal transport cost. Consequently, the capital cost for both a bituminous and an anthracite plant has to be determined, including not

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[1]At this time it is unclear whether partial or no scrubbing will be allowed. For the purpose of analysis, we assume a case where scrubbing is not required.

Table 4-2

SCENARIOS FOR DETERMINING MAXIMUM ANTHRACITE PRICE

Emission Regulation	Bituminous Coal Type	Bituminous Particulate Control	Bituminous Sulfur Control	Anthracite Coal Type	Anthracite Particulate Control	Anthracite Sulfur Control
NSPS	Low Sulfur	Fabric Filter	No FGD	Either	Fabric Filter	No FGD
	High Sulfur	ESP	FGD	Either	Fabric Filter	No FGD
BACT-L	Low Sulfur	Fabric Filter	FGD	Low Sulfur	Fabric Filter	FGD
	High Sulfur	ESP	FGD	Low Sulfur	Fabric Filter	FGD
BACT-VL	Low Sulfur	Fabric Filter	FGD	Very Low Sulfur	Fabic Filter	No FGD
	High Sulfur	ESP	FGD	Very Low Sulfur	Fabric Filter	No FGD
BACT/ VARIANCE	Low Sulfur	Fabric Filter	FGD	Either	Fabric Filter	No FGD
	High Sulfur	ESP	FGD	Either	Fabric Filter	No FGD

SOURCE: See text. Note that Fabric Filters are assumed for bituminous coal to provide a consistent basis for comparison, since they are estimated to have the lowest cost.

Table 4-3

DEMAND PRICE FOR ANTHRACITE

$$F^A_{1985} = \left[(K^B_{1985} - K^A_{1985}) + \sum_{y=1985}^{2019} \left[(r^B_o)^{y-1985} O^B_y - (r^A_o)^{y-1985} O^A_y \right] + \sum_{y=1985}^{2019} \left[(r^B_t)^{y-1985} T^B_y - (r^A_t)^{y-1985} T^A_y \right] + \sum_{y=1985}^{2019} \left[(r^B_f)^{y-1985} F^B_y \right] \right] \Bigg/ \sum_{y=1985}^{2019} (r^A_f)^{y-1985}.$$

where terms are defined in Table 4-1 and $r_k = \frac{1+l_k}{1+d}$ for $k = o, f, t$

and $l^B_o = l^A_o = .018$

$l^B_f = .029$

$l^A_f = .022$

$l^A_t = l^B_t = .033$

$d = .0775$

Note: These real escalation rates $\{l_x\}$ are discussed in the text.

only the boilers and the necessary peripheral equipment, but any required environmental control equipment. In addition, the operating costs for both types of units have to be calculated for each year in the time horizon, including the minemouth coal prices.

We use the net present value approach to derive a range of anthracite demand prices for each of six potential coal-burning plants described in Chapter 2. To apply this approach, we define prototype 500 megawatt plants for each equipment combination described in Table 4-2. We assume capital and operating costs are the same at each plant location and that all plants can purchase coal at the same minemouth price. However, fuel transportation costs vary by plant. Therefore, differences in the range of demand prices by plant result from these differences in transportation costs.

We present estimated demand prices for the six utilities in a subsequent section. First, we present the estimates of capital cost, operating costs (excluding coal costs), bituminous coal prices, transport costs, and fuel requirements used in developing these prices. The capital and operating cost estimates are drawn primarily from reports by Bechtel[1] and PEDCo.[2] and discussions with equipment manufacturers. The bituminous coal prices and transport cost estimates are forecasts derived from CRA's work and the CRA Coal Market Model.[3]

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[1]Bechtel Power Corporation, *Coal-Fired Power Plant Capital Cost Estimates*, prepared for Electric Power Research Institute, Palo Alto, Calif., January 1977.

[2]PEDCo., *Particulate and Sulfur Dioxide Emission Control Costs*.

[3]Charles River Associates, "CRA/EPRI Coal Market Analysis System: Overview," Boston, Mass., forthcoming.

To estimate demand prices, we use these costs to determine which bituminous coal type provides the lowest cost of generation for each scenario. Then, using that bituminous coal type as the alternative fuel, we apply the equation in Table 4-3, to develop the demand price.

Capital and Operating Costs (Excluding Fuel) for Prototype Plants

There is limited published information on total capital and operating costs for new coal-burning units. The two primary sources relied on were a report by Bechtel Power Corporation for the Electric Power Research Institute, *Coal-Fired Power Plant Capital Cost Estimates*, and a report by PEDCo. Environmental, Incorporated, for the Environmental Protection Agency, *Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers*. Neither report included both capital and operating costs for all equipment considered in this study. To estimate the capital and operating costs for the prototype plants used in this report we relied on Bechtel's capital cost estimates for a coal-burning plant, without environmental control equipment, and used PEDCo.'s capital and operating cost estimates for pollution control equipment.

Because we used two data sources we had to reconcile various assumptions such as allowance for funds during construction, real rates of inflation, and completion dates.[1]

[1]See Appendix A for details.

Capital Cost Estimates for a 500 Megawatt Unit Without Environmental Control Equipment

Using Bechtel's report for the Electric Power Research Institute, *Coal-Fired Power Plant Capital Cost Estimates*, we estimated total capital costs (excluding environmental control costs) for a 500 MW bituminous coal plant located in Northeastern Pennsylvania coming on-line in 1985 at 414.6 million (1977 dollars).[1] This figure also accounted for other owners' costs, such as land rights, cost of rights of ways, water rights and other costs associated with obtaining the necessary licenses to build a plant and allowance for funds during construction, which is the cost of borrowed and other funds used during construction.

The capital cost for a 500 megawatt anthracite boiler is approximately 30-40 percent more primarily due to the larger volume of the anthracite boiler. It is very difficult to burn anthracite coal to completion and to facilitate this anthracite boilers are between one and one-half to two times larger in volume. The capital costs for an anthracite unit however are only approximately 15 percent more because the other equipment on a coal unit, such as turbines and steam pipes, are the same whether the coal is anthracite or bituminous.[2] Using the 15 percent factor, the capital cost for an anthracite unit coming on-line in 1985 would be approximately $477 million (in 1977 dollars).[3]

Capital Cost Estimates for Environmental Control Equipment

With the new air quality regulations, capital investment for coal-burning plants has increased significantly because of

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[1]See Appendix A for a description of how Bechtel 1985 costs were converted to 1977 dollars so that the capital costs would agree with the fuel operating costs which were in 1977 dollars.

[2]Conversation with Fred Ceely, Sales Division, Foster-Wheeler Energy Corporation, August 11, 1978.

[3]See Appendix A for capital cost calculation.

It is more economical to use bituminous coal plants than anthracite plants, since for most cost categories bituminous plants are less costly than anthracite units and, in those categories where anthracite is less expensive, the cost savings are not large enough to offset the costs in other categories. These cost tradeoffs are as follows.

- Under both current and proposed emission regulations, there are bituminous coal units with the necessary emission control equipment with lower capital and operating costs (exclusive of coal) than there are for anthracite plants.
- Anthracite plants require 2 percent more Btu's per kilowatt hour than do bituminous plants.
- Costs of transporting bituminous coal to New England localities exceeds the cost of transporting Narragansett coal.
- Narragansett anthracite production costs are twice as large as bituminous production costs per Btu.

Because of uncertainty about the actual quality of Narragansett coal deposits and mining costs, uncertainty about cost of operating anthracite plants, and the prospects of users being tied to a few sources of supply, we feel the price differentials facing users are, at a minimum, those described above. Consequently we concluded that there would not be a market for Narragansett coal in the next ten years.

In subsequent chapters we discuss in some detail the market analyses summarized here. We begin with a definition of the market in Chapter 2. In Chapter 3, we discuss the emission policies and characteristics of the Narragansett Basin coal deposit that affect the prices consumers would pay for coal and users would accept. In Chapter 4, we estimate prices users would pay for anthracite coal, and in Chapter 5 we estimate a minimum price producers would accept for Narragansett anthracite. In this chapter, we compare these prices, concluding that the Narragansett coal deposits would not be developed commercially in the next ten years.

Chapter 2
COAL MARKET DEFINITION

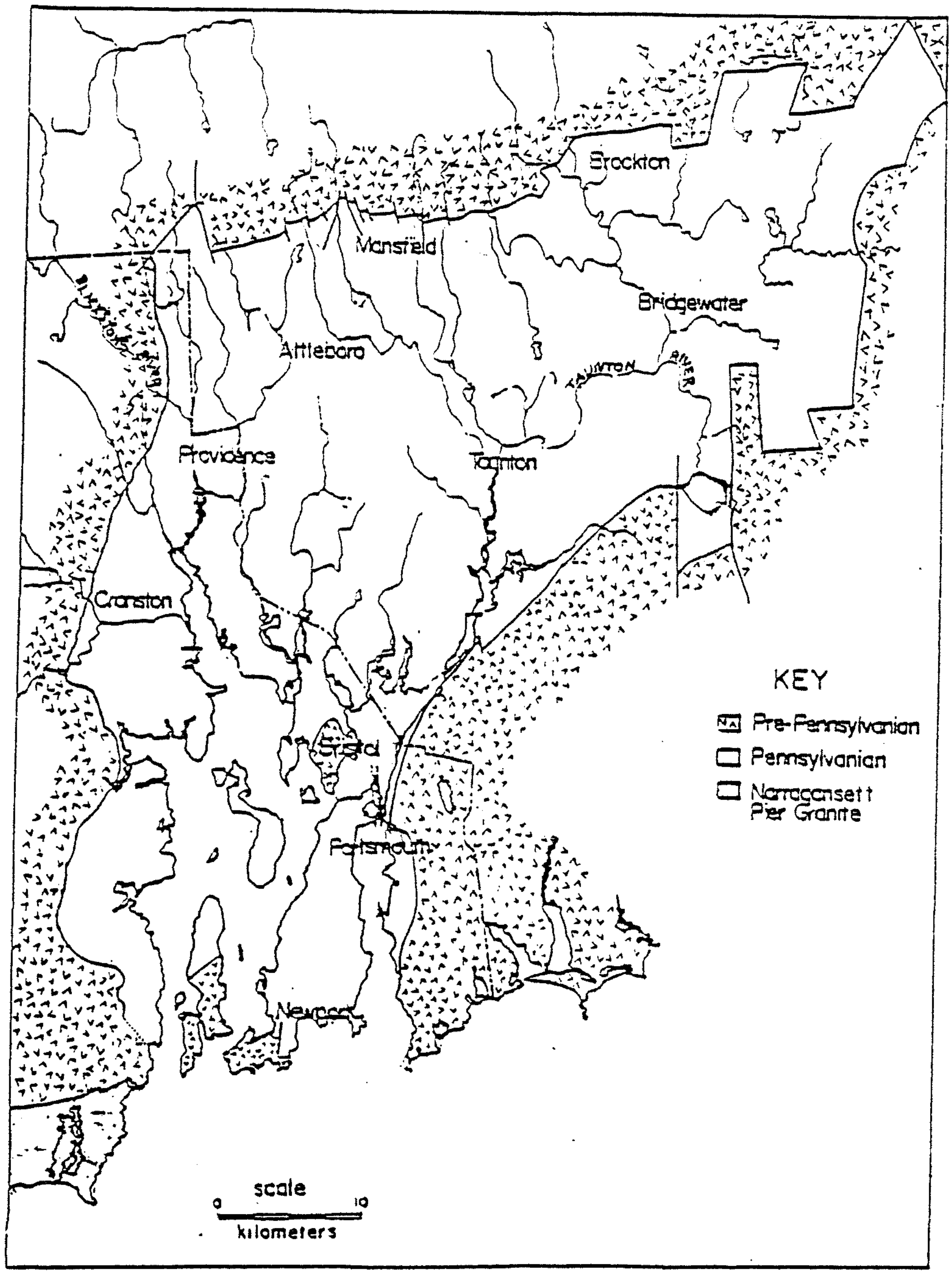
The economic viability of Narragansett Basin Coal requires that the coal meet some energy requirement at a lower cost than any alternative source. Currently, the major market for coal is electricity generation, particularly utility generation. If utilities can generate electricity using Narragansett Basin anthracite coal, at a lower cost than bituminous coal, or other fuel sources, then utilities form a potential market for this coal.

Utility Demand For Coal

Narragansett Basin coal is located in southwestern Massachusetts and eastern Rhode Island, as shown in Figure 2-1. Consequently, New England utility generating units, existing and planned, are potential candidates for a major portion of the market. In particular, existing coal burning units, existing units with orders to convert to coal, and other planned units without construction licenses, shown in Table 2-1, could be potential candidates for burning anthracite coal. The planned units are designed only for nuclear or coal use.

Figure 2–1

GEOGRAPHY OF THE NARRAGANSETT BASIN



SOURCE: Weston Observatory, Boston College, Interim Report of the Pennsylvanian Coal-Bearing Strata of the Narragansett Basin of Massachusetts and Rhode Island June 1976—December 1976. (Washington: U.S. Bureau of Mines, 1978) p. 5.

emission control equipment. The magnitude of this investment, as mentioned earlier, is dependent upon the local environmental regulations and the kind of coal a utility buys. Regardless of coal type, all plants have to install particulate control equipment to meet the current particulate emission limits of .05 - .1 pounds per 10^6 Btu under NSPS and .03 pounds per 10^6 Btu under BACT. The magnitude of the capital investment differs by coal quality. Bituminous coal-burning plants primarily use electrostatic precipitators to control particulate release. In 1985 the capital cost for this equipment will range between $12.4 million for eastern high sulfur coal and $27.1 million for eastern low sulfur coal to meet Best Available Control Technology.[1] The capital cost on electrostatic precipitators varies between high and low sulfur coal because low sulfur coal has higher resistivity.[2]

Fabric filters are the best means for controlling particulate release when burning anthracite again because of resistivity. The coal cannot be charged up sufficiently to effectively use an electrostatic precipitator. The capital investment for 1985 is estimated at $27.1 million (in 1977 dollars), $6.5 million less than the cost of an ESP in a plant burning low sulfur coal under the most stringent 0.03 pounds per 10^6 Btu regulation.

Sulfur dioxide emission levels are established for new plants and the manner in which they are met varies by scenario, whether NSPS is in effect or whether BACT has been established.

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[1]See PEDCo., *Particulate and Sulfur Dioxide Emissions Control Costs*; and Appendix A.

[2]Resistivity is the ability to charge ash with electricity; the higher the resistivity the harder it is to remove ash using electrostatic precipitators. See *Ibid.*

With this in mind, we calculated capital costs for lime flue gas desulfurization equipment for both high and low sulfur coal and for anthracite coal. A desulfurization unit processing high sulfur coal to meet the 1.2 pounds of SO_2 per million Btu standard requires a capital investment of $57.9 million for a 500 MW unit. Assuming 90 percent SO_2 removal, the total capital investment required for a 500 MW flue gas desulfurization unit burning low sulfur coal is $49.8 million and $64.6 million for high sulfur coal in 1985 (1977 dollars). The capital costs for FGD in a 500 MW anthracite plant are estimated at $54.0 million.

Because of the different coal types and emission scenarios, the capital costs for units, particulate control and sulfur control will vary as noted above. In Table 4-4, we summarize the capital cost estimates that are used in evaluating the anthracite demand prices.

Operating Cost Estimates for Bituminous and Anthracite Plants (Excluding Fuel Costs)

Operating and maintenance costs for coal-burning units depend upon the quality of coal burned. Consequently, anthracite environmental control operating and maintenance costs can range from 0-100 percent more than a bituminous unit depending upon the quality of the anthracite coal burned. Anthracite operation and maintenance costs, however, will never be less than in a bituminous plant.[1]

We assumed the best case for anthracite, namely that all nonfuel and nonenvironmental control equipment operating and maintenance costs were the same. This includes such items as pulverizers, fans, boiler tubes and ash removal equipment. Because the prototype plants used in this report are assumed to be baseload the higher start-up costs associated with an anthracite plant are negligible.

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[1]Conversation with Fred Ceely, Sales Division, Foster Wheeler.

Table 4-4

CAPITAL COSTS FOR 1985 UNITS
(million 1977 dollars)

Bituminous		Unit w/o Emission Control	Particulate Control		Sulfur Control
Low Sulfur	NSPS	414.6	Fabric Filter	27.1	--
High Sulfur	NSPS	414.6	ESP	12.4	FGD 57.9
Low Sulfur	BACT	414.6	Fabric Filter	27.1	FGD 49.8
High Sulfur	BACT	414.6	ESP	14.7	FGD 64.6
Anthracite					
	NSPS	476.7	Fabric Filter	27.1	--
	BACT	476.7	Fabric Filter	27.1	FGD 54.0

SOURCE: Appendix A.

Electrostatic precipitators' operating costs vary (as did capital costs) by coal quality. High sulfur coal has lower operating costs than low sulfur coal. Annual operating costs for an ESP in a 500 MW plant burning high sulfur bituminous coal is $1.5 million annually in 1985, under the BACT scenario (see Table 4-5). The lowest operating costs are on a fabric filter at $970,000 in 1985. Even though the fabric filter's capital costs run more than the lowest ESP capital cost, the operating costs are always less.

The estimated flue gas desulfurization annual operating costs are estimated at $8.34 million for low sulfur bituminous coal and $12.24 million for high sulfur bituminous coal under BACT; $11.16 million for high sulfur bituminous coal under NSPS. FGD costs for anthracite coal under BACT are estimated at $7.7 million.

The Tennessee Valley Authority estimated costs for a limestone FGD system installed in a plant burning high sulfur coal. TVA's capital cost estimates after it was inflated to 1980 dollars was 23 percent less than PEDCo.'s estimate, while TVA's operating cost estimate was 41 percent less than PEDCo.'s.[1] TVA's FGD estimates are for a different FGD system from the one we have chosen. However, these lower estimates, when compared to PEDCo.'s limestone FGD estimates, should be kept in mind as they could influence a utility's decision regarding what type of plant they may build in the future.

Coal Costs

Annual coal costs are a function of the minemouth price of the coal, the transportation costs and the annual coal requirements. The annual coal requirements vary depending on the heat rate (defined as Btu's of heat input required to generate one kilowatt-hour) which is determined by the plant design. The

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[1]TVA's figures were escalated to 1980 dollars using a 7.5 percent escalation rate. PEDCo., *Particulate and Sulfur Dioxide Emission Control Costs*, pp. 4-37 and 4-38.

Table 4-5

ANNUAL OPERATING COSTS FOR 1985
(EXCLUDING COAL COSTS)
(millions of 1977 dollars)

Bituminous		Unit w/o Emission Control	Particulate Control		Sulfur Control	
Low Sulfur	NSPS	[1]	Fabric Filter	0.97	N.A.	
High Sulfur	NSPS	[1]	ESP	1.28	FGD	11.16
Low Sulfur	BACT	[1]	Fabric Filter	0.97	FGD	8.34
High Sulfur	BACT	[1]	ESP	1.54	FGD	12.24
Anthracite						
	NSPS	[1]	Fabric Filter	0.97	--	
	BACT	[1]	Fabric Filter	0.97	FGD	8.03

[1]For the purpose of analysis, we assume the operating costs of the units have no major effect on the unit choice. As noted in the text, the anthracite coal operating costs would in fact exceed bituminous coal operating costs.

SOURCE: Appendix A.

heat rate on plants with scrubbers and plants designed to burn anthracite coal are higher. The annual consumption and thus the annual fuel cost is greater for these plants than those bituminous plants which do not have scrubbers.

Bituminous Minemouth Prices

Minemouth prices for bituminous coal were developed from 1985 prices forecast using the CRA Coal Market Analysis System. Prices were forecast for two emission scenarios, NSPS and BACT. As shown in Table 4-6, the prices for high and low sulfur coal differ slightly under these scenarios. High sulfur prices are several dollars higher under the BACT scenario than under the NSPS scenario. Low sulfur prices are several dollars lower under the NSPS scenario. All 1985 prices are between \$20.00 and \$27.00 per ton (in 1977 dollars) for the coal qualities specified in the scenarios.[1]

Transportation Costs

Coal sufficient to support a generating station normally moves under high volume or unit train rates or under bulk commodity barge rates. For the purpose of developing price estimates, we used forecasts of unit-train rates. These rates assume delivery of 100,000 tons a year and minimum train loads of 7,000 tons each.

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[1]This system forecasts minemouth coal prices by rank and sulfur type for major coal-burning regions, using a mathematical programming model to solve for market clearing prices of a spatially competitive market. That is, the forecasts reflect a market in which the user chooses the lowest cost fuel source and producers face sufficient competition to prohibit excess profits. Alternative assumptions about key factors that affect price and production, such as sulfur emission regulations, coal mining wage trends, mining equipment cost trends, productivity trends, coal resource availability, tax policies, and coal transport rate trends can be input to the model and consequently reflected in the price forecasts. The methodology used in these forecasts and in the version of the model developed for EPRI is described in Charles River Associates Incorporated, *CRA/EPRI Coal Market Analysis System: Overview*, Vol. I and *Technical Background*, Vol. II (forthcoming).

Table 4-6

1985 BITUMINOUS MINEMOUTH FUEL PRICES
(in 1977 dollars)

	Coal Quality			1985 Prices (in 1977 dollars)			
				\$/Ton		$\$/10^6$ Btu	
	Btu/lb[1]	Lb SO_2/ 10^6 Btu[1]	Lbs Ash/ 10^6 Btu[1]	NSPS	BACT	NSPS	BACT
High Sulfur PA, NW VA	12,076	3.72	.103	\$19.94[2]	\$21.07	\$ .83	\$.87
Low Sulfur SW VA, KY	12,536	1.13	.089	\$26.64	\$24.08	\$1.06	\$.96

[1]SOURCE: Federal Power Commission, Cost and Quality of Electric Utility Plant Fuels, 1976.

[2]Excess Capacity of High Sulfur Coal Leads to Price Estimates of \$16.91 for Pennsylvania Coal.

SOURCE: CRA Coal Market Analysis System: CRA/EPRI version, special runs, June 1977.

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The rate forecasting equation is based on several models estimated by Zimmerman[1] and on estimates of actual rate increases between 1970 and 1977 and forecasts of real escalation developed by CRA. The forecast equation we use is

$$R_{19xy} = (2.00)\ (1.033)^{19xy-1977}(2.415 + .00369M)$$

where

xy = the forecast year

M = the distance between supply and demand pairs

The first coefficient (*2.00*) adjusts for rate increases between 1970 and 1977, the second coefficient adjusts prices for real escalation between 1977 and the forecast year, and the remaining coefficients estimate 1970 rates. The 1970 rates represent an average of rate forecasts by Zimmerman for the East and Midwest. [2]

Rates for 1985, in 1977 prices, used in this analysis are shown in Table 4-7. For the net present value calculations, we also used rates over the life of the plant. These rates are forecast using a real escalation factor of 3.3 percent per year growth in transportation rates.

Coal Requirements

To estimate annual coal costs, we used estimates of the tons of coal required to generate power for a 500 megawatt unit. The annual coal requirements are determined by the total generation (kilowatt hours) per year, the heat rate (Btu's per kilowatt hour) and the Btu content of the coal (Btu's per ton). The heat rate varies by boiler type (anthracite, bituminous) and

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[1] Martin B. Zimmerman, "Long-Run Model Supply: The Case of Coal in The United States," PhD Dissertation, Department of Economics, MIT, September, 1975.

[2] For a further discussion of the derivation of the transport rate equation see: Charles River Associates Incorporated, *CRA/EPRI Coal Market Forecasting System, Technical Background* (forthcoming).

Table 4-7

1985 Transportation Distance and Cost
(In 1977 Dollars)

	Destination							
	Charlestown, R.I.		Plymouth, Mass.		Greenfield, Mass.		Searsport, Maine	
Origin	(Miles)	(Dollars/ ton)	(Miles)	(Dollars/ ton)	(Miles)	(Dollars/ ton)	(Miles)	(Dollars/ ton)
Maldsville, W. Va. Low Sulfur Bituminous	818	14.09	876	14.83	692	12.88	1047	16.27
Altoona, Pa. High Sulfur Bituminous	666	12.63	744	13.38	546	11.48	895	14.83
Bristol, R.I. Anthracite	55	6.79	98	7.20	120	7.41	396	10.05

SOURCE: Distance data obtained by Fay Associates.
Rate forecasts estimated using method described in the text.

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by the type of emission control equipment at the unit. In addition the Btu content varies among the coals.

Using information about the generation characteristics of the prototype units, we develop estimates of Btu requirements per year for bituminous and anthracite units, with and without desulfurization units. These Btu requirements were converted into tonnage requirements for the two bituminous coal types and the anthracite coal type, by using the Btu's per pound specified for each coal type in Table 3-2. The resulting tonnage of coal per year is given in Table 4-8.

Narragansett Anthracite Demand Price

The maximum demand price that a utility would pay for anthracite coal for each of the four scenarios (NSPS, BACT-L, BACT-LV, BACT/Variance) establishes a likely range for demand prices. For any given location, these price ranges are calculated using capital costs, operating costs (excluding fuel), minemouth bituminous coal prices, coal transportation cost, and coal requirements, given in Tables 4-4 through 4-8. These resulting demand prices will vary somewhat by location, because of differences in transportation costs.

To develop these demand prices, we first identify the bituminous coal type that provides power at minimum cost. The costs used to make this comparison are presented in Table 4-9. As the table shows, the bituminous low sulfur coal has the least cost under the NSPS scenario. While there is not a significant difference between the costs of generation using high and low sulfur coal under the BACT scenario, we choose the high sulfur coal as the basis of comparison with anthracite coal since there is a large supply of high sulfur coal in the east and more experience with particulate control units (ESPs) for high sulfur coal.

Table 4-8

GENERATION REQUIREMENTS OF PROTOTYF
(500 MW Capacity)

	Bituminous Units	
	Without Scrubber	With Scrubber
Capacity Factor[1]	.70	.70
Heat Rate (Btu/kwh)[2]	9,428.6	9,834
Annual Net Generation (kwh's)[3]	$3{,}066 \times 10^6$	$3{,}066 \times 10^6$
Annual Btu Requirements (Btu's)[4]	$28{,}908 \times 10^6$	$30{,}151 \times 10^9$
Annual Coal Requirements (Tons)[5]		
Bituminous @ $25{,}072 \times 10^3$ Btu/Ton - Low	1.153×10^6	1.203×10^6
Bituminous @ $24{,}156 \times 10^3$ Btu/Ton - High	1.197×10^6	1.248×10^6
Anthracite @ $22{,}500 \times 10^3$ Btu/Ton	----	----

[1]EPRI, *op. cit.*, pp. 1-8.

[2]Heat rate with scrubbers is taken from EPRI, *op. cit.*, pp. 1-8; Heat rate withou with scrubbers, 9834, by 1.043. 1.043 taken from EPA, *op. cit.*, pp. 4-21.

[3]Net Btu generation = capacity factor x capacity x hours per year = capacity fact

[4]Btu's/year for bituminous coal = annual net generation x heat rate. Btu's/year This is based on a memo by R. M. Dunn to J. G. Hayward, Coal Task Force Ad Hoc Energy Narragansett Basin Anthracite," January 27, 1978.

[5]Tons/year = Btu's/year ÷ Btu's/ton. The Btu's/ton correspond to the Btu content

Table 4-9

1985 NET PRESENT COSTS OF GENERATION AT PROTOTYPE BITUMINOUS PLANTS
(Millions of 1977 Dollars)

	New Source Performance Standards		Best Available Control Technology	
	Low Sulfur	High Sulfur	Low Sulfur	High Sulfur
Capital Costs[1]				
Unit	414.6	414.6	414.6	414.6
Particulate Control				
0.1 lbs./10^6 Btu	27.1	12.4	N.A.	N.A.
0.05 lbs./10^6 Btu	27.1	N.A.	N.A.	N.A.
0.03 lbs./10^6 Btu	N.A.	N.A.	27.1	14.7
Sulfur Control				
1.2 lbs./10^6 Btu	N.A.	57.9	N.A.	N.A.
90 Percent Removal	N.A.	N.A.	49.8	64.6
Operating Costs (Excluding Fuel)[2]				
Plant	**	**	**	**
Particulate Control				
0.1 lbs./10^6 Btu	15.2	20.0	N.A.	N.A.
0.05 lbs./10^6 Btu	15.2	N.A.	N.A.	N.A.
0.03 lbs./10^6 Btu	N.A.	N.A.	15.2	24.1
Sulfur Control				
1.2 lbs./10^6 Btu	N.A.	174.4	N.A.	N.A.
90 Percent Removal	N.A.	N.A.	130.4	191.3
Fuel Costs				
Minemouth[3]	545.98	442.83	515.75	467.73
Transportation[4]				
Charlestown, RI	303.48	294.44	316.64	294.44
Plymouth, MA	319.42	311.93	333.27	311.93
Greenfield, MA	277.42	267.64	289.45	267.64
Searsport, ME	350.43	345.73	365.63	345.73

Table continued on following page.

Table 4-9 (Continued)

1985 NET PRESENT COSTS OF GENERATION AT PROTOTYPE BITUMINOUS PLANTS
(Millions of 1977 Dollars)

	New Source Performance Standards		Best Available Control Technology	
	Low Sulfur	High Sulfur	Low Sulfur	High Sulfur
Total Costs at:[5]				
Charlestown, RI	1,306.36	1,416.57	1,469.49	1,471.47
Plymouth, MA	1,322.30	1,434.06	1,486.12	1,488.96
Greenfield, MA	1,280.30	1,389.77	1,442.30	1,444.67
Searsport, ME	1,353.31	1,467.86	1,518.48	1,522.76

[1]These capital costs are taken from Table 4-4.

[2]These costs are estimated as:

$$\sum_{k=0}^{34} \left(\frac{1+e_o}{1+d}\right)^k * \text{ annual operating cost where } e_o = 0.018 \text{ and } d = .0775.$$

The annual operating costs are taken from Table 4-5.

[2]These costs are estimated as:

$$\sum_{k=0}^{34} \left(\frac{1+e_t^B}{1+d}\right)^k * \text{ fuel requirements } * \text{ minemouth prices, where } e_t^B = .029 \text{ and } d = .0775.$$

The fuel requirements are taken from Table 4-8 and the minemouth prices are taken from Table 4-6.

Table continued on following page.

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Table 4-9 (Continued)

1985 NET PRESENT COSTS OF GENERATION AT PROTOTPYE BITUMINOUS PLANTS
(Millions of 1977 Dollars)

[4]These costs are estimated as:

$$\sum_{k=0}^{34} \left(\frac{1+e_f}{1+d}\right)^k$$ * fuel requirements * transport cost per ton where $e_f = .033$ and $d = .0775$.

The fuel requirements are taken from Table 4-8 and the transport costs are taken from Table 4-7.

[5]These costs are the sum of the capital, operating and coal costs for each location.

N.A.: The standard (such as particulate control of 0.03 lbs./10^6 Btu) is not part of the emission scenario (i.e., New Source Performance Standards, Best Available Control Technology).

The maximum anthracite price is then developed for each scenario using the bituminous coal type with minimum generating costs as the alternative fuel. The costs used for anthracite plants for this comparison are shown in Table 4-10.

Using the relationship described in Table 4-2, we develop demand prices for anthracite for each scenario and each location. These demand prices are the maximum price that a user located at one of the designated locations, specified in Table 4-10, would pay a producer at the mine for anthracite coal with qualities specified in Table 3-2, given the alternative coals available. As shown in Table 4-11, the price at any location varies up to $10 by scenario. In particular, users at Charlestown, R.I. are willing to pay between $26.90 and $36.60 for anthracite coal at Bristol, R.I.; users at Plymouth, Mass. are willing to pay between $27.18 and $36.90; users at Greenfield, Mass. are willing to pay between $24.98 and $34.62; and users at Searsport, Maine are willing to pay between $25.37 and $35.16 for anthracite coal at Bristol, R.I.

Table 4-10

1985 NET PRESENT COSTS OF GENERATION AT PROTOTYPE ANTHRACITE PLANTS
(Millions of 1977 Dollars)

	NSPS	BACT-L	BACT-VL and BACT/Variance
Capital Costs[1]			
Plant	476.7	476.7	476.7
Particulate Control	27.1	27.1	27.1
Sulfur Control	--	54.0	--
Operating Costs (Excluding Coal)[2]			
Plant	**	**	**
Particulate Control	15.2	15.2	15.2
Sulfur Control	--	121.5	--
Coal Costs			
Minemouth[3]	***	***	***
Transportation:[4]			
Charlestown, RI	166.2	173.4	166.2
Plymouth, MA	176.2	183.8	176.2
Greenfield, MA	181.3	189.2	181.3
Searsport, ME	245.9	256.6	245.9
Total Costs (Excluding FOB Coal Costs and Other Costs) at:			
Charlestown, RI	685.2	867.9	685.2
Plymouth, MA	695.2	878.3	695.2
Greenfield, MA	700.3	883.7	700.3
Searsport, ME	764.9	951.1	764.9

[1]The capital costs are taken from Table 4-4.

[2]The operating costs are estimated as:

$$\sum_{k=0}^{34}\left(\frac{1+e_o}{1+d}\right)^k$$ * annual operating costs, where $e_o = 0.018$ and $d = .0775$.

The annual operating costs are taken from Table 4-5.

Table continued on following page.

Table 4-10 (Continued)

1985 NET PRESENT COSTS OF GENERATION AT PROTOTYPE ANTHRACITE PLANTS
(Millions of 1977 Dollars)

[3]These costs are not estimated.

[4]These costs are estimated as:

$$\sum_{k=0}^{34}\left(\frac{1+e_t}{1+d}\right)^k$$ * fuel requirements * transport cost per ton, where $e_t = .033$ and $d = .0775$.

The fuel requirements are taken from Table 4-8 and the transport costs are taken from Table 4-7.

[5]These costs are the sum of the capital, operating, and coal transport costs for each location.

** See text for explanation of why plant operation costs are excluded.

*** The minemouth price is the output of the analysis.

Table 4-11

1985 DEMAND MINEMOUTH PRICE FOR ANTHRACITE
(In 1977 Dollars)

	NSPS	BACT-L	BACT-LV and BACT Variance
Net Present Value Differential[1] (Millions of Dollars)			
Charlestown, RI	621.16	601.59	784.29
Plymouth, MA	627.10	607.82	790.92
Greenfield, MA	580.00	558.60	742.00
Searsport, ME	588.41	567.38	753.58
Anthracite Coal Requirements[2] (tons/year)	1.310×10^6	1.367×10^6	1.310×10^6
Demand Price for Anthracite[3]			
Charlestown, RI	28.98	26.90	36.60
Plymouth, MA	29.26	27.18	36.90
Greenfield, MA	27.06	24.98	34.62
Searsport, ME	27.46	25.37	35.16

[1]The cost differential is the difference between the total costs for each location and scenario given in Tables 4-9 and 4-10.

[2]The anthracite coal requirements per year are taken from Table 4-8.

[3]The demand price is calculated as:

$$\frac{\mathit{Cost\ Differential}}{\sum_{k=0}^{34}\left(\frac{1+e_f}{1+d}\right)^k * \mathit{Anthracite\ Coal\ Requirements}}$$

where

$e_f = .022$ and $d = .0775$.

This formula is based on the relationship described in Table 4-2.

Chapter 5

SUPPLY PRICE OF ANTHRACITE

To assess the likely supply prices for anthracite, we estimate the costs of producing coal for the two resource scenarios described in Chapter 3. As shown in Table 5-1, one scenario describes a deposit amenable to underground mining, the other describes a deposit amenable to surface mining. In both cases, we evaluate costs assuming existing mining technologies that would be used in the 10-year time frame of the study.

The costs presented in this chapter are taken from Appendix B, a report on anthracite mining prepared by Charles Manula. The costs in Appendix B are for 1978 in 1978 dollars. Our analysis uses costs for 1985 in 1977 dollars. Based on estimated factor shares and escalation rates for labor, capital and materials, we use an

Table 5-1

Seam Characteristic Scenarios

Underground Breast Mining	
Thickness	5.4 Feet
Depth	463 Feet
Dip	> 20°
Continuity	Good[1]

Surface Mining	
Thickness	5.4 Feet
Depth	< 400 Feet
Stripping Ratio	15:1 to 20:1
Continuity	Good[1]

[1]We expect the deposit's continuity is not good. However, because of extreme uncertainty we make the assumption that continuity is good in order to obtain the lowest mining costs.

escalation rate of 2.5 percent for underground mines and a rate of 2.2 percent for surface mines.[1]

Underground Mining

For underground mining the key geological assumption affecting mining costs is the dip angle of the seams. Since the scenario assumes seam dip exceeds 20°, conventional mining techniques cannot be used; rather the alternative to conventional mining, breast mining, is used. For seams inclined less than 35°, chute breast mining is employed; for seams from 35° to 90°, inclination battery breasts are used. Since our analysis of the geology of the Narragansett Basin based on existing data indicates that some seams will have dips over 35°, some form of breast mining must be used. Because the two techniques have similar costs,[2] we need not distinguish cost for chute versus battery breast mining.

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[1]Based on related work, we expect real escalation rates of 4.2 percent for labor, 2.3 percent for capital and 0.6 percent for materials for coal mining. From the Berger Associates and A. B. Riedel Associates Report "Evaluation of Mining Constraints to the Revitalization of Pennsylvania Anthracite," prepared for the U. S. Bureau of Mines, March 1975, we derive the following percentage factor shares for underground and surface anthracite mines.

	Underground	Surface
Labor	39	25
Materials	29	34
Capital	32	41

These factor shares and the factor escalation rates imply an escalation rate of 2.5 percent for underground mines and a rate of 2.2 percent for surface mines. To adjust prices from 1978 to 1977, we use an escalation rate of 6.8 percent.

[2]See Appendix B.

The current cost of mining anthracite in Pennsylvania with either chute breast or battery breast techniques is about $24 per ton, run-of-mine (ROM). According to Manula, a new operation would have an additional development expense for drivage of rock tunnels and investment expenses for the shaft and ventilation tunnels. We assume that the mine will have an average depth of 463 feet. For new mines in the range of 300 to 600 feet deep, the capital costs are about $15 per annual ton of output.[1] When amortized over the typical mine life, 20 years, at 8 percent, the additional cost per ton (average fixed cost) becomes $1.53.[2] Consequently, the estimated total mining cost per ton of Narragansett Basin coal, ROM, becomes

$24.00	current costs of operations in Pennsylvania
1.53	additional costs for new mines
$25.53	

Before the ROM coal could be used, it would have to be processed through a coarse coal preparation plant to remove the shale and rock partings. According to Manula this processing would cost $1.90 per ton of clean coal and have a yield of 70 percent. After preparation, the cost of usable coal would be $38.39. These costs are for 1978 operation in 1978 dollars; when adjusted for 1985 operation in 1977 dollars, the cost is $42.73.

These cost estimates assume that the seam will have sufficient continuity to support a mine of normal life. A 125,000 ton per year operation produces 2.5 million tons over a 20 year life and requires 5 million tons of reserves at a 50 percent rate of recovery. The geographic scope of a deposit with 5 million tons of reserves depends on the

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[1]See Appendix B.

[2]Amortization rates for private coal development are apt to be higher than 8 percent, and consequently the anthracite production costs represent a low estimate.

density of the anthracite and the average thickness of the seam. Assuming a density of 120 pounds per cubic foot, an average seam thickness of 5.4 feet, and a width of the seam of 1200 feet, the seam would have to be 2.4 miles long. A 500 MW base load power plant would require the annual output of 11 such mines. The logistical effort to locate the deposits, open the mines, and develop the distribution network for 11 mines would deter utilities from using this coal. If each mine's output level were 200,000 tons per year rather than 125,000 tons, only 7 mines would be needed. This level of output exceeds the output of the largest single underground anthracite mine and would require a deposit 60 percent larger than the one used in our example.

A second consideration in underground mining of anthracite on a large scale is the necessity to employ skilled labor in breast mining. According to Manula, this underground mining system requires highly trained and skilled practitioners. The requirements for a single 500 MW power plant exceed underground anthracite production in 1975 by a factor of two. The additional labor requirements to meet the fuel needs of such a plant with underground mining would be double current employment in the industry.

Surface Mining

Surface mining can be accomplished on a larger scale than underground mining and its greater capital intensity means that its requirements for skilled labor are much lower. Another advantage of surface mining is the high recovery factor for reserves (90 percent). However, a major disadvantage of surface mining is the environmental disruption associated with it.

The major determinant of the cost of surface mining is the stripping ratio. The stripping ratio is the cubic yards of overburden that must be removed per ton of clean coal recovered. The overburden is the layers of rock and dirt over the coal seam that must first be broken up by blasting before a dragline or shovel can remove it. We develop surface mining costs for two stripping ratios likely to occur in the Basin 15:1 and 20:1.

Table A-6 presents the cost of surface mining for different strip ratios. These costs include the fixed and operating costs for blasting of overburden, overburden removal, loading and hauling the coal, and reclamation of the land. The reclamation costs assume that the land will be returned to its original contour and usable for forest or pasture. It does not include the cost of restoring the land to specialized uses. Reclamation costs for New England would be higher than for Pennsylvania so these cost estimates represent minimums.

These costs per ton of run of mine coal for the 15:1 and 20:1 stripping ratios are approximately $27 and $37 for 1978 production in 1978 dollars and approximately $29 and $40 for 1985 production in 1977 dollars. The coal will require cleaning to remove shale and rock partings. Assuming a reject level of 30 percent and a cost of $1.90 for removal of rock and shale partings, the coal costs would be $40.50 and $55 respectively in 1978. The respective costs in 1985 (in 1977 dollars) would be $44 and $60.

These cost estimates are based on the assumption that deposits being mined are sufficiently continuous to support a mine throughout its life. If we assume that the power plant is to get its fuel needs from two separate surface mines, then each mine would need a capacity of 700,000 tons per year. The mine life for surface mines ranges from 20 to 30 years; for a 25 year mine life and a 90 percent recovery factor, each mine would require reserves of 19.4 million tons. For a seam 5.4 feet thick with a density of 120 pounds per cubic foot, an area of deposits, about 1.5 miles square for each mine would be required. If the deposit were 2000 feet wide, it would have to be 6 miles long.

Summary - Anthracite Mining Costs

Because of our assumptions about continuity, reclamation costs, and our selection of seam characteristics, the costs developed in this chapter reflect some of the best mining conditions that will occur in the Narragansett Basin. We estimate underground mining costs in 1985 of approximately $43 per ton of clean coal and surface mining costs in the range of $44-$60 per ton of clean coal in 1977 dollars. This results in an expected range of supply prices of $43-$60 per ton of clean coal at the mine in 1985 (in 1977 dollars).

Appendix A
CAPITAL AND OPERATING COST ESTIMATES FOR A 500 MEGAWATT COAL UNIT

The capital and operating cost estimates (excluding coal costs) used in deriving demand prices in this study are for a facility completed in 1984, for initial operation in 1985. These costs are presented in 1977 dollars and are based on cost estimates developed by Bechtel[1] and PEDCO.[2] Although we required both total facility or boiler costs and all emission control costs, neither report contained both. Therefore, we developed an estimate of facility cost (exclusive of emission control costs) using the Bechtel report and estimates of emission control costs from the PEDCO report.

In both cases, the costs had to be adjusted to 1977 dollars and to reflect a 1985 completion date. These costs

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[1]Bechtel Power Corporation, *Coal-Fired Power Plant Capital Cost Estimates* (Palo Alto Ca.: January 1977). Prepared for Electric Power Research Institute.

[2]PEDCO Environmental, Incorporated, *Particulate and Sulfur Dioxide Emission Control Costs for Large Coal Fired Boilers* (Research Triangle Park, North Carolina: February 1978). Prepared for the Environmental Protection Agency.

were adjusted by first deflating them to reflect 1977 operations in 1977 dollars, and then by escalating them to reflect 1985 operation in 1977 dollars. Since PEDCO's emission control cost estimates for plant completion in 1980 in 1980 dollars were escalated from 1976 dollars, using an escalation rate of 7.5 percent, we obtained costs for 1977 completion in 1977 dollars by deflating 1980 costs by 7.5 percent for three years. Bechtel's plant cost estimates were for plant completion in 1978, with a center of gravity of expenditures in 1976 (1976 dollars were used). We inflated Bechtel's costs to 1977 dollars using the 7 percent (real and inflation) escalation rate which was inherent in the Bechtel cost estimates.

The PEDCO and Bechtel 1977 cost estimates were then escalated to reflect real cost changes between 1977 and the center of gravity of expenditures for actual plant completion (1983 in this case). The real annual rate of cost escalation was estimated to be 1.8 percent, based on subtracting the GNP deflator of 5.2 percent, the average inflation rate between 1964 and 1976, from Bechtel's 7 percent annual escalation rate, which includes both inflation and real cost changes. Consequently, we used a real escalation factor of $(1.018)^6 = 1.113$ for capital costs and $(1.018)^8 = 1.26$ for operating costs. Final cost estimates are in 1977 dollars for 1985 plant operation.

PEDCO and Bechtel also used different values of interest during construction. Therefore, we first adjusted the costs to put them on a consistent basis. To do this, we netted out PEDCO's interest during construction and added in interest calculated at the rate assumed by Bechtel. In particular, PEDCO estimated Interest During Construction (IDC) at 10 percent annually, while Bechtel included a 16 percent credit for Allowance for Funds During Construction (AFDC). In our capital cost estimations for environmental control equipment, we netted out PEDCO's 10 percent IDC and added in AFDC based on 16 percent of the total capital cost, following Bechtel's methods.

Other Owners Costs were included in the Bechtel capital cost estimates. PEDCO incorporated Other Owners Costs (land and land rights, engineering and home office, plant equipment, supplies and startup costs, and taxes and insurance) into their fixed charge estimates of emission control costs. Bechtel assumes that Other Owners Costs will be 7 percent of the total capital costs. We applied the Bechtel rate of 7 percent to the PEDCO capital costs, and did not utilize PEDCO estimates of fixed charges.

In the remainder of this appendix, the capital and operating costs that are used in the analysis in Chapter 4 are developed from the PEDCO and Bechtel estimates.

Table A-1

CAPITAL COST ESTIMATES FOR A 500 MW
BITUMINOUS COAL PLANT WITHOUT ENVIRONMENTAL CONTROLS
(Thousands of Dollars)

		Capital Cost Estimates
1.	Plant Cost without SO_2 Removal, Electrostatic Precipitators, Other Owners Costs, and Allowance for Funds During Construction for two 500 MW units (1976 dollars) for 1978 completion.	519,400[1]
2.	Percentage of Total Plant Cost (1.) for a 500 MW Unit.	54 percent[1]
3.	Total Plant Cost for a 500 MW Unit (1976 dollars)	280,500[2]
4.	Other Owners Costs as a percentage of Capital Costs	7 percent[1]
5.	Other Owners Costs (1976 dollars)	19,600[3]
6.	Total Plant Costs (1976 dollars)	300,000[4]
7.	Allowance for Funds During Construction as a percentage of Total Costs	16 percent[1]
8.	Allowance for Funds During Construction (1976 dollars)	48,500[5]
9.	Total Estimated Project Cost (1976 dollars for operation in 1978)	348,100[6]
10.	Total Estimated Project Cost (1977 dollars for operation in 1978)	372,500[7]
11.	Total Estimated Project Cost for Plant Operation in 1985 (1977 dollars)	414,600[8]

Table continued on following page.

Table A-1 (Continued)

CAPITAL COST ESTIMATES FOR A 500 MW
BITUMINOUS COAL PLANT WITHOUT ENVIRONMENTAL CONTROLS
(Thousands of Dollars)

Footnotes to Table A-1

[1]Bechtel Power Corporation, *Coal-Fired Power Plant Capital Cost Estimates*. Prepared for Electric Power Research Institute, San Francisco, January 1977, pp. 8-4 and 805. We used Bechtel's capital costs for a Northeast plant location.

[2]Calculated by multiplying line (2) by line (1).

[3]Calculated by multiplying line (4) by line (3).

[4]Sum of line (3) and line (5)

[5]Calculated by multiplying line (7) by line (6)

[6]Sum of line (6) and line (8).

[7]Derived by escalating line (9) by 7 percent, the total escalation rate assumed by Bechtel.

[8]Derived by escalating line (10) by 1.8 percent between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985. The real escalation rate of plant costs estimated for this period is 1.8 percent.

Table A-2

CAPITAL COST ESTIMATES FOR A 500 MW
ANTHRACITE COAL PLANT WITHOUT ENVIRONMENTAL CONTROLS
(thousands of dollars)

		Capital Cost Estimates
1.	Bituminous 500 MW Plant Cost Without Environmental Controls (1976 Dollars for 1978 operation)	280,500[1]
2.	Percentage Increase in Anthracite Plant over Bituminous Plant	15 percent[2]
3.	Total Plant Cost for a 500 MW Anthracite Unit	322,500[3]
4.	Other Owners Costs as a percentage of Capital Costs	7 percent[4]
5.	Other Owners Costs (1976 Dollars)	22,600[5]
6.	Total Plant Costs (1976 Dollars)	345,100[6]
7.	Allowance for Funds During Construction as percentage of Total Costs	16 percent[7]
8.	Allowance for Funds During Construction (1976 dollars)	55,200[8]
9.	Total Estimated Project Cost (1976 dollars for operation in 1978)	400,300[9]
10.	Total Estimated Project Cost (1977 dollars for operation in 1978)	428,300[10]
11.	Total Estimated Project Cost for Plant Operation in 1985 (1977 Dollars)	476,700[11]

Table continued on following page.

Table A-2 (Continued)

CAPITAL COST ESTIMATES FOR A 500 MW
ANTHRACITE COAL PLANT WITHOUT ENVIRONMENTAL CONTROLS
(thousands of dollars)

Footnotes to Table A-2.

[1]From line (3.) of Table A-1.

[2]Based on conversations with boiler manufacturers and architect-engineers, it was determined that an anthracite plant would cost 15 percent more than an equivalent bituminous plant (see Text, Chapter 4).

[3]Calculated by adding percentage increase of line (2.) to line (1.).

[4]From line (4.) of Table A-1.

[5]Calculated by multiplying line (4.) times line (3.).

[6]Sum of line (3.) and line (5.).

[7]From line (7.) of Table A-1.

[8]Calculated by multiplying (7.) times (6.).

[9]Sum of line (6.) and line (8.).

[10]Derived by escalating line (9.) by 7 percent for one year, the total escalation rate assumed by Bechtel.

[11]Derived by escalating line (10.) by 1.8 percent between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985. The real escalation rate of plant costs estimated for this period is 1.8 percent.

Table A-3

ELECTROSTATIC PRECIPITATOR CAPITAL COST ESTIMATE FOR A 500 MW PLANT UTILIZING EASTERN HIGH SULFUR COAL AND MEETING 13.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

	Capital Cost Estimates
1. Capital Cost for 500 MW (1980 dollars for 1980 plant completion)	15,910[1]
2. PEDCO Estimate of Interest During Construction (1980 dollars)	904[2]
3. Total Capital Cost less Interest During Construction (1980 dollars)	15,006[3]
4. Bechtel Estimate of Allowance for Funds During Construction as a percentage of Capital Cost	16 percent[4]
5. Allowance for Funds During Construction (1980 dollars)	1,446[5]
6. Total Estimated Project Cost (1980 dollars for operation in 1980)	16,452[6]
7. Total Estimated Project Cost (1977 dollars for operation in 1977)	13,243[7]
8. Total Estimated Project Cost (1977 dollars for 1985 plant operation)	14,739[8]

Table continued on following page.

Table A-3 (Continued)

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN HIGH SULFUR
COAL AND MEETING 13.0 Ng/JOULE
PARTICULATE EMISSION REGULATION
(thousands of dollars)

Footnotes to Table A-3.

[1]PEDCO Environmental, Inc. *Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers,* prepared for U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1978, p. 3-12.

[2]PEDCO used a different rate of Interest During Construction (10 percent) than the percentage Allowance for Funds During Construction used by Bechtel for plant costs (Table A-1). Thus, PEDCO's IDC was netted out from their total cost estimates and AFDC at the Bechtel rate of 16 percent was added in. To net out the IDC, we assumed that the ratio of IDC to total capital investment would be the same for all environmental control equipment examined in this study. This ratio was derived from a computer print-out of lime flue gas desulfurization costs by component provided in the PEDCo. Report. The ratio of IDC to total capital investment for the lime FGD was 5,682 percent. This ratio was applied to line (1.) to estimate line (2.).

[3]Line (1.) minus (2.).

[4]Bechtel Power Corporation, *op. cit.,* p. 8-5.

[5]Allowance for Funds During Construction (AFDC) was estimated using approximately the same procedure as described in Note 2. above. In PEDCo's lime FGD cost breakdown, Interest During Construction was estimated at 10 percent of total installed cost plus sludge pond cost (see Table A-10). For the lime FGD, AFDC was estimated at 16 percent of this same cost. The ratio of AFDC to total capital investment cost was then estimated for the lime FGD (9.09 percent) and then applied to line (3.) to obtain line (5.).

[6]Line (3.) plus line (5.).

[7]Derived by deflating line (6.) by 7.5 percent per year for three years. 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[8]Derived by escalating line (7.) by 1.8 percent between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-4

ELECTROSTATIC PRECIPITATOR CAPITAL COST ESTIMATE FOR A 500 MW PLANT UTILIZING EASTERN LOW SULFUR COAL AND MEETING 13.0 Ng/JOULE PARTICULATE EMISSION REGULATION (thousands of dollars)

		Capital Cost Estimate
1.	Capital Cost for 500 MW Utilizing Western Low Sulfur Coal (1980 dollars for 1980 operation)	40,355[1]
2.	Capital Cost Credit due to Lower Moisture Content of Eastern Low Sulfur Coal (1980 dollars)	4,036[2]
3.	Capital Cost for 500 MW Utilizing Eastern Low Sulfur Coal (1980 dollars)	36,319[3]
4.	PEDCo Estimate of Interest During Construction (1980 Dollars)	2,064[4]
5.	Total Capital Cost Less Interest During Construction (1980 dollars)	34,255[5]
6.	Bechtel Estimate of Allowance for Funds During Construction as a percentage of Capital Cost	16 percent[6]
7.	Allowance for Funds During Construction (1980 dollars)	3,301[7]
8.	Total Estimated Project Cost (1980 dollars for 1980 operation)	37,556[8]
9.	Total Estimated Project Cost (1977 dollars for 1977 operation)	30,231[9]
10.	Total Estimated Project Cost (1977 dollars for 1985 plant operation)	33,647[10]

Table continued on following page.

Table A-4 (Continued)

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN LOW SULFUR COAL
AND MEETING 13.0 Ng/JOULE
PARTICULATE EMISSION REGULATION
(thousands of dollars)

Footnotes to Table A-4.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Conversation with Larry Gibbs, PEDCo., June 2, 1978. The estimate for low-sulfur ESP costs from p. 3-12 in PEDCo. Report was based on western low sulfur coal at 0.8 percent sulfur. According to Gibbs, eastern low-sulfur coal has a lower moisture content, thus reducing volumetric flow of flue gas and lowering annual capital costs on the order of about 10 percent. Operation and maintenance costs are not affected. Thus, line (2.) is 10 percent of line (1.), representing capital cost credit for eastern low sulfur coal.

[3]Line (1.) minus line (2.).

[4]Estimated in the same manner as described in Note 2. to Table A-3; 5.682 percent of line (3.).

[5]Line (3.) minus line (4.).

[6]Bechtel Power Corporation, *op. cit.*

[7]Estimated in the same manner as described in Note 5. to Table A-3; 9.09 percent of line (3.).

[8]Line (5.) plus line (7.).

[9]Derived by deflating line (8.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[10]Derived by escalating line (9.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-5

ELECTROSTATIC PRECIPITATOR CAPITAL COST ESTIMATE FOR A 500 MW PLANT UTILIZING EASTERN HIGH SULFUR COAL AND MEETING 22.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

		Capital Cost Estimate
1.	Capital Cost for 500 MW (1980 dollars)	14,105[1]
2.	PEDCo. Estimate of Interest During Construction (1980 dollars)	801[2]
3.	Total Capital Cost less Interest During Construction (1980 dollars)	13,304[3]
4.	Estimate of Allowance for Funds During Construction (1980 dollars)	1,282[4]
5.	Total Estimated Project Cost (1980 dollars)	14,586[5]
6.	Total Estimated Project Cost (1977 dollars)	11,741[6]
7.	Total Estimated Project Cost (1977 dollars for 1985 plant completion)	13,068[7]

Table continued on following page.

Table A-5 (Continued)

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN HIGH SULFUR COAL
AND MEETING 22.0 Ng/JOULE PARTICULATE
EMISSION REGULATION
(thousands of dollars)

Footnotes to Table A-5.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Estimated in the same manner as described in Note 7. to Table A-3; 5.682 percent of line (1.).

[3]Line (1.) minus line (2.).

[4]Estimated in the same manner as described in Note 5. to Table A-3; 9.09 percent of line (1.).

[5]Line (3.) plus line (4.).

[6]Derived by deflating line (5.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[7]Derived by escalating line (6.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-6

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT UTILIZING
EASTERN LOW SULFUR COAL AND MEETING
22.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

	Capital Cost Estimate
1. Capital Cost for 500 MW Utilizing Western Low Sulfur Coal (1980 dollars)	34,225[1]
2. Capital Cost Credit due to Lower Moisture Content of Eastern Low Sulfur Coal (1980 dollars)	3,423[2]
3. Capital Cost for 500 MW Utilizing Eastern Low Sulfur Coal (1980 dollars)	30,802[3]
4. PEDCo Estimate of Interest During Construction (1980 dollars)	1,750[4]
5. Total Capital Cost Less Interest During Construction (1980 dollars)	29,052[5]
6. Estimate of Allowance for Funds During Construction (1980 dollars)	[6]2,800[6]
7. Total Estimated Project Cost (1980 dollars)	31,852[7]
8. Total Estimated Project Cost (1977 dollars)	25,640[8]
9. Total Estimated Project Cost (1977 dollars for 1985 plant operation)	28,537[9]

Table continued on following page.

Table A-6 (Continued)

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT UTILIZING
EASTERN LOW SULFUR COAL AND MEETING
22.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

Footnotes to Table A-6.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Same as Note 2. to Table A-4. Eastern low-sulfur coal has a 10 percent capital credit relative to western low sulfur coal. Line (2.) is 10 percent of line (1.).

[3]Line (1.) minus line (2.).

[4]5.682 percent of line (3.). (Note 2. to Table A-3).

[5]Line (3.) minus line (4.).

[6]9.09 percent of line (3.). (Note 5. to Table A-3).

[7]Line (5.) plus line (6.).

[8]Derived by deflating line (8.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[9]Derived by escalating line (8.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-7

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT UTILIZING
EASTERN HIGH SULFUR COAL AND MEETING
43.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

	Capital Cost Estimates
1. Capital Cost for 500 MW (1980 dollars for 1980 operation)	13,425[1]
2. PEDCo. Estimate of Interest During Construction (1980 dollars)	763[2]
3. Total Capital Cost less Interest During Construction (1980 dollars)	12,662[3]
4. Estimate of Allowance for Funds During Construction (1980 dollars)	1,220[4]
5. Total Estimated Project Cost (1980 dollars for 1980 operation)	13,882[5]
6. Total Estimated Project Cost (1977 dollars for 1977 operation)	11,174[6]
7. Total Estimated Project Cost (1977 dollars for 1985 plant completion)	12,437[7]

Table continued on following page.

Table A-7 (Continued)

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT UTILIZING
EASTERN HIGH SULFUR COAL AND MEETING
43.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

Footnotes to Table A-7.

[1] PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2] Estimated in the same manner as described in Note 2. to Table A-3; 5.682 percent of line (1.).

[3] Line (1.) minus line (2.).

[4] Estimated in the same manner as described in Note 5. to Table A-3; 9.09 percent of line (1.).

[5] Line (3.) plus line (4.).

[6] Derived by deflating line (5.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[7] Derived by escalating line (6.) by 1.2 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-8

ELECTROSTATIC PRECIPITATOR CAPITAL COST ESTIMATE FOR A 500 MW PLANT UTILIZING EASTERN LOW SULFUR COAL AND MEETING 43.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

		Capital Cost Estimate
1.	Capital Cost for 500 MW Utilizing Western Low Sulfur Coal (1980 dollars for 1980 operation)	26,265[1]
2.	Capital Cost Credit due to Lower Moisture Content of Eastern Low-Sulfur Coal (1980 dollars)	2,622[2]
3.	Capital Cost for 500 MW Utilizing Eastern Low Sulfur Coal (1980 dollars)	23,638[3]
4.	PEDCo. Estimate of Interest During Construction (1980 dollars)	1,343[4]
5.	Total Capital Cost Less Interest During Construction (1980 dollars)	22,295[5]
6.	Estimate of Allowance for Funds During Construction (1980 dollars)	2,149[6]
7.	Total Estimated Project Cost (1980 dollars for 1980 operation)	24,444[7]
8.	Total Estimated Project Cost (1977 dollars for 1977 operation)	19,676[8]
9.	Total Estimated Project Cost (1977 dollars for 1985 plant operation)	21,899[9]

Table continued on following page.

Table A-8 (Continued)

ELECTROSTATIC PRECIPITATOR CAPITAL COST
ESTIMATE FOR A 500 MW PLANT UTILIZING
EASTERN LOW SULFUR COAL AND MEETING
43.0 Ng/JOULE PARTICULATE EMISSION REGULATION
(thousands of dollars)

Footnotes to Table A-8.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Same as Note 2. to Table A-4. Eastern low-sulfur coal has a 10 percent capital credit relative to western low sulfur coal. Line (2.) is 10 percent of line (1.).

[3]Line (1.) minus line (2.).

[4]5.682 percent of line (3.). (Note 2. to Table A-3).

[5]Line (3.) minus line (4.).

[6]9.09 percent of line (3.). (Note 5 to Table A-3).

[7]Line (5.) plus line (6.).

[8]Derived by deflating line (8.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[9]Derived by escalating line (8.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditure for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-9

FABRIC FILTER CAPITAL COST ESTIMATE
FOR A 500 MW PLANT UTILIZING
EASTERN LOW-SULFUR COAL OR ANTHRACITE
(thousands of dollars)

		Capital Cost Estimate
1.	Capital Cost for 500 MW (1980 dollars for 1980 operation)	29,225[1]
2.	PEDCo. Estimate of Interest During Construction (1980 dollars)	1,661[2]
3.	Total Capital Cost less Interest During Construction (1980 dollars)	27,564[3]
4.	Estimate of Allowance for Funds During Construction (1980 dollars)	2,657[4]
5.	Total Estimated Project Cost (1980 dollars for 1980 operation)	30,221[5]
6.	Total Estimated Project Cost (1977 dollars for 1977 operation)	24,327[6]
7.	Total Estimated Project Cost (1977 dollars for 1985 plant operation)	27,076[7]

Table continued on following page.

Table A-9 (Continued)

FABRIC FILTER CAPITAL COST ESTIMATE
FOR A 500 MW PLANT UTILIZING
EASTERN LOW-SULFUR COAL OR ANTHRACITE
(thousands of dollars)

Footnotes to Table A-9.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Estimated in the same manner as described in Note 2. to Table A-3; 5.682 percent of line (1.).

[3]Line (1.) minus line (2.).

[4]Estimated in the same manner as described in Note 5. to Table A-3; 9.09 percent of line (1.).

[5]Line (3.) plus line (4.).

[6]Derived by deflating line (5.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[7]Derived by escalating line (6.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-10

LIME FLUE GAS DESULFURIZATION CAPITAL COST ESTIMATE FOR A 500 MW PLANT UTILIZING EASTERN HIGH-SULFUR COAL WITH 90 PERCENT REMOVAL (thousands of dollars)

		Capital Cost Estimate
1.	Capital Investment for 500 MW (1980 dollars for 1980 operation)	69,729 [1]
2.	PEDCo. Estimate of Interest During Construction (1980 dollars)	3,962 [2]
3.	Total Capital Investment less Interest During Construction (1980 dollars)	65,767 [3]
4.	Total Equipment Installed Cost (1980 dollars)	31,630 [4]
5.	Capital Cost of Sludge Pond (1980 dollars)	7,986 [5]
6.	Installed Cost of Equipment and Sludge Pond (1980 dollars)	39,616 [6]
7.	Bechtel Estimate of Percentage Allowance for Funds During Construction	16 percent[7]
8.	Allowance for Funds During Construction (1980 dollars)	6,339 [8]
9.	Total Estimated Project Cost (1980 dollars for 1980 operation)	72,106 [9]
10.	Total Estimated Project Cost (1977 dollars for 1977 operation)	58,042 [10]
11.	Total Estimated Project Cost (1977 dollars for 1985 plant operation)	64,601 [11]

Table continued on following page.

Table A-10 (Continued)

LIME FLUE GAS DESULFURIZATION CAPITAL COST
ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN HIGH-SULFUR COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars)

Footnotes to Table A-10.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. xxxiii.

[2]*Ibid.*, p. C-8.

[3]Line (1.) minus line (2.).

[4]PEDCo. Environmental, Inc., *op. cit.*, p. C-7.

[5]*Ibid.*

[6]Line (4.) plus line (5.).

[7]Bechtel Power Corporation, *op. cit.*, p. 8-5.

[8]Interest During Construction in PEDCo. Report is estimated as 10 percent of the Installed Cost of Equipment and Sludge Pond (line (6.)). Thus, AFDC at the Bechtel rate is calculated as 16 percent of line (6.).

[9]Line (3.) plus line (8.).

[10]Derived by deflating line (9.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[11]Derived by escalating line (6.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-11

LIME FLUE GAS DESULFURIZATION CAPITAL
COST ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN LOW-SULFUR COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars)

		Capital Cost Estimates
1.	Capital Investment for 500 MW Plant Utilizing Western Low-Sulfur Coal (1980 dollars for 1980 operation)	59,710 [1]
2.	PEDCo. Estimate of Interest During Construction (1980 dollars)	3,383 [2]
3.	Total Capital Investment less Interest During Construction (1980 dollars)	56,327 [3]
4.	Total Equipment Installed Cost (1980 dollars)	30,035 [4]
5.	Capital Cost of Sludge Pond (1980 dollars)	3,793 [5]
6.	Installed Cost of Equipment and Sludge Pond (1980 dollars)	33,828 [6]
7.	Bechtel Estimate of Percentage Allowance for Funds During Construction	16 percent [7]
8.	Allowance for Funds During Construction (1980 dollars)	5,412 [8]
9.	Total Estimated Project Cost for Western Low-Sulfur Coal (1980 dollars)	61,739 [9]
10.	Capital Cost Credit due to Utilizing Eastern Low-Sulfur Coal (1980 dollars)	6,173 [10]
11.	Total Estimated Project Cost for Eastern Low-Sulfur Coal (1980 dollars for 1980 operation)	55,565 [11]

Table continued on following page.

Table A-11 (Continued)

LIME FLUE GAS DESULFURIZATION CAPITAL
COST ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN LOW-SULFUR COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars)

		Capital Cost Estimates
12.	Total Estimated Project Cost for Eastern Low-Sulfur Coal (1977 dollars for 1977 operation)	44,728 [12]
13.	Total Estimated Project Cost for Eastern Low-Sulfur Coal (1977 dollars for 1985 plant operation)	49,782 [13]

Table A-11 (Continued)

LIME FLUE GAS DESULFURIZATION CAPITAL
COST ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN LOW-SULFUR COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars)

Footnotes to Table A-11.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. xxxii.

[2]*Ibid.*, p. C-13.

[3]Line (1.) minus line (2.).

[4]PEDCo. Environmental, Inc., *op. cit.*, p. C-12.

[5]*Ibid.*

[6]Line (4.) plus line (5.).

[7]Bechtel Power Corp., *op. cit.*, p. 8-5.

[8]Interest During Construction in PEDCo. Report is estimated as 10 percent of the Installed Cost of Equipment and Sludge Pond (line (6.)). Thus, AFDC at the Bechtel rate is calculated as 16 percent of line (6.).

[9]Line (3.) plus line (8.).

[10]Conversation with Larry Gibbs, *op. cit.* Line (10.) is 10 percent of line (9.).

[11]Line (9.) minus line (10.).

[12]Derived by deflating line (11.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[13]Derived by escalating line (12.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-12

LIME FLUE GAS DESULFURIZATION CAPITAL COST ESTIMATE FOR A 500 MW PLANT UTILIZING ANTHRACITE COAL WITH 90 PERCENT REMOVAL
(thousands of dollars)

		Capital Cost Estimate
1.	Capital Investment for 500 MW (1980 dollars for 1980 operation)	58,285 [1]
2.	PEDCo. Estimate of Interest During Construction (1980 dollars)	3,312 [2]
3.	Total Capital Cost less Interest During Construction (1980 dollars)	54,973 [3]
4.	Estimate of Allowance for Funds During Construction (1980 dollars)	5,298 [4]
5.	Total Estimated Project Cost (1980 dollars for 1980 operation)	60,271 [5]
6.	Total Estimated Project Cost (1977 dollars for 1977 operation)	48,516 [6]
7.	Total Estimated Project Cost (1977 dollars for 1985 Plant Completion)	53,998 [7]

Table continued on following page.

Table A-12 (Continued)

LIME FLUE GAS DESULFURIZATION CAPITAL
COST ESTIMATE FOR A 500 MW PLANT
UTILIZING ANTHRACITE COAL WITH
90 PERCENT REMOVAL
(thousands of dollars)

Footnotes to Table A-12.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. xxxii.

[2]5.682 percent of line (1.). (Note 2, Table A-3).

[3]Line (1) minus line (2.).

[4]9.09 percent of line (1.). (Note 5, Table A-3).

[5]Line (3.) plus line (4.).

[6]Derived by deflating line (5.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[7]Derived by escalating line (6.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-13

LIME FLUE GAS DESULFURIZATION
CAPITAL COST ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN HIGH-SULFUR COAL AND MEETING 1.2
LBS. $SO_2/10^6$ Btu STANDARD
(thousands of dollars)

		Capital Cost Estimate
1.	Capital Investment for 500 MW Plant (1980 dollars for 1980 operation)	62,465 [1]
2.	PEDCo. Estimate of Interest During Construction (1980 dollars)	3,549 [2]
3.	Total Capital Cost less Interest During Construction (1980 dollars)	58,916 [3]
4.	Estimate of Allowance for Funds During Construction (1980 dollars)	5,679 [4]
5.	Total Estimated Project Cost (1980 dollars for 1980 operation)	64,595 [5]
6.	Total Estimated Project Cost (1977 dollars for 1977 operation)	51,996 [6]
7.	Total Estimated Project Cost (1977 dollars for 1985 Plant Completion)	57,870 [7]

Table continued on following page.

Table A-13 (Continued)

LIME FLUE GAS DESULFURIZATION
CAPITAL COST ESTIMATE FOR A 500 MW PLANT
UTILIZING EASTERN HIGH-SULFUR COAL AND MEETING 1.2
LBS. $SO_2/10^6$ Btu STANDARD
(thousands of dollars)

Footnotes to Table A-13.

[1]PEDCo. Environmental Inc., *op. cit.*, p. xxxii.

[2]5.682 percent of line (1.). (Note 2, Table A-3).

[3]Line (1.) minus line (2.).

[4]9.09 percent of line (1.). (Note 5, Table A-3).

[5]Line (3.) plus line (4.).

[6]Derived by deflating line (5.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[7]Derived by escalating line (6.) by 1.8 percent per year between 1977 and 1983, the center of gravity of expenditures for a plant beginning operation in 1985; 1.8 percent represents the real escalation rate of capital costs estimated for this period.

Table A-14

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR ELECTROSTATIC PRECIPITATORS ON A 500 MW PLANT UTILIZING EASTERN
HIGH - SULFUR COAL
(thousands of dollars except as noted)

	O & M Costs By Particulate Regulation		
	13.0 ng/joule	22.0 ng/joule	43.0 ng/joule
1. O & M Cost in 1980 dollars (mills/Kwh)[1]	0.54	0.47	0.45
2. Annual Generation (10^6 Kwh)[2]	3066	3066	3066
3. Annual Cost (1980 dollars for 1980 operation)[3]	1,656	1,441	1,380
4. Annual Cost (1977 dollars for 1977 operation)[4]	1,333	1,160	1,111
5. Annual Cost (1977 dollars for Plant Operation in 1985)[5]	1,537	1,338	1,281

Table continued on following page.

Table A-14 (Continued)

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR ELECTROSTATIC PRECIPITATORS IN A 500 MW PLANT UTILIZING EASTERN
HIGH - SULFUR COAL
(thousands of dollars except as noted)

Footnotes to Table A-14.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Annual generation is calculated assuming a 70 percent capacity factor for a 500 MW plant;

$$\begin{aligned}\text{Annual Generation (Kwh)} &= \text{Capacity factor} \times \text{Capacity} \times \text{Hours/year}\\ &= (0.70) \times (500 \times 10^3) \times (8760)\\ &= 3066 \times 10^6 \text{ Kwh.}\end{aligned}$$

[3]Line (1.) times line (2.).

[4]Derived by deflating line (3.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[5]Derived by escalating line (4.) by 1.8 percent per year between 1977 and 1985, the initial year of plant operation; 1.8 percent represents the real escalation rate of operation and maintenance costs estimated for this period.

Table A-15

ANNUAL OPERATION AND MAINTENANCE
COSTS FOR ELECTROSTATIC PRECIPITATORS ON A 500 MW PLANT UTILIZING
EASTERN LOW-SULFUR COAL
(thousands of dollars except as noted)

		O & M Costs By Particulate Regulation		
		13.0 ng/joule	22.0 ng/joule	43.0 ng/joule
1.	O & M Cost in 1980 dollars[1] (mills/Kwh)	1.36	1.17	0.89
2.	Annual Generation[2] (10^6 Kwh)	3066	3066	3066
3.	Annual Cost (1980 dollars for 1980 operation)[3]	4,170	3,587	2,729
4.	Annual Cost (1977 dollars for 1977 operation)[4]	3,357	2,888	2,197
5.	Annual Cost (1977 dollars for Plant Operation in 1985)[5]	3,872	3,331	2,534

Table A-15 (Continued)

ANNUAL OPERATION AND MAINTENANCE
COSTS FOR ELECTROSTATIC PRECIPITATORS ON A 500 MW PLANT UTILIZING
EASTERN LOW-SULFUR COAL
(thousands of dollars except as noted)

Footnotes to Table A-15.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Annual generation is calculated assuming a 70 percent capacity factor for a 500 MW plant;

$$\text{Annual Generation (Kwh)} = \text{Capacity factor} \times \text{Capacity} \times \text{hours/year}$$
$$= (0.70) \times (500 \times 10^3) \times (8760)$$
$$= 3066 \times 10^6 \text{ Kwh.}$$

[3]Line (1.) times line (2.).

[4]Derived by deflating line (3.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[5]Derived by escalating line (4.) by 1.8 percent per year between 1977 and 1985, the initial year of plant operation; 1.8 percent represents the real escalation rate of operation and maintenance costs estimated for this period.

Table A-16

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR FABRIC FILTERS ON A 500 MW PLANT
UTILIZING EASTERN LOW - SULFUR COAL OR ANTHRACITE
(thousands of dollars except as noted)

		O & M Costs
1.	Annual O & M Cost in 1980 dollars (mills/Kwh)	0.34[1]
2.	Annual Generation (10^6 Kwh)	3,066[2]
3.	Annual Cost (1980 dollars for 1980 operation)	1,042[3]
4.	Annual Cost (1977 dollars for 1977 operation)	839[4]
5.	Annual O & M Cost (1977 dollars for Plant Operation in 1985)	968[5]

Table continued on following page.

Table A-16 (Continued)

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR FABRIC FILTERS ON A 500 MW PLANT
UTILIZING EASTERN LOW - SULFUR COAL OR ANTHRACITE
(thousands of dollars except as noted)

Footnotes to Table A-16.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. 3-12.

[2]Annual generation is calculated assuming a 70 percent capacity factor for a 500 MW plant;

$$\text{Annual Generation (Kwh)} = \text{Capacity factor} \times \text{Capacity} \times \text{hours/year}$$
$$= (0.70) \times (500 \times 10^3) \times (8760)$$
$$= 3066 \times 10^6 \text{ Kwh.}$$

[3]Line (1.) times line (2.).

[4]Derived by deflating line (3.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[5]Derived by escalating line (4.) by 1.8 percent per year between 1977 and 1985, the initial year of plant operation; 1.8 percent represents the local escalation rate of operation and maintenance costs estimated for this period.

Table A-17

ANNUAL OPERATION AND MAINTENANCE
COSTS FOR A LIME FLUE GAS DESULFURIZATION SYSTEM
ON A 500 MW PLANT UTILIZING EASTERN HIGH-SULFUR COAL
(thousands of dollars except as noted)

		O & M Costs by Sulfur Emission Regulation	
		1.2 Lbs. $SO_2/10^6$ Btu	90 Percent Removal
1.	Annual O & M Cost in 1980 dollars[1] (mills/Kwh)	3.92	4.30
2.	Annual Generation[2] (10^6 Kwh)	3,066	3,066
3.	Annual Cost (1980 dollars for 1980 operation)[3]	12,019	13,184
4.	Annual Cost (1977 dollars for 1977 operation)[4]	9,675	10,613
5.	Annual O & M Cost (1977 dollars for Plant Operation in 1985)[5]	11,159	12,241

Table continued on following page.

Table A-17 (Continued)

ANNUAL OPERATION AND MAINTENANCE
COSTS FOR A LIME FLUE GAS DESULFURIZATION SYSTEM
ON A 500 MW PLANT UTILIZING EASTERN HIGH-SULFUR COAL
(thousands of dollars except as noted)

Footnotes to Table A-17.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. xxxii.

[2]Annual generation is calculated assuming a 70 percent capacity factor for a 500 MW plant;

$$\text{Annual Generation (Kwh)} = \text{Capacity factor} \times \text{Capacity} \times \text{hours/year}$$
$$= (0.70) \times (500 \times 10^3) \times (8760)$$
$$= 3066 \times 10^6 \text{ Kwh.}$$

[3]Line (1.) times line (2.).

[4]Derived by deflating line (3.) by 7.5 percent per year for three years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[5]Derived by escalating line (4.) by 1.8 percent per year between 1977 and 1985, the initial year of plant operation; 1.8 percent represents the real escalation rate of operation and maintenance costs estimated for this period.

Table A-18

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW PLANT
UTILIZING EASTERN LOW - SULFUR COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars except as noted)

		O & M Costs
1.	Annual O & M Cost in 1980 dollars (mills/Kwh)	2.93[1]
2.	Annual Generation (10^6 Kwh)	3,066[2]
3.	Annual Cost (1980 dollars for operation in 1980)	8,983[3]
4.	Annual Cost (1977 dollars for operation in 1977)	7,231[4]
5.	Annual O & M Cost (1977 dollars for Plant Operation in 1985)	8,340[5]

Table continued on following page.

Table A-18 (Continued)

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW PLANT
UTILIZING EASTERN LOW - SULFUR COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars except as noted)

Footnotes to Table A-18.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. xxxii.

[2]Annual generation is calculated assuming a 70 percent capacity factor for a 500 MW plant;

Annual Generation (Kwh) = Capacity factor × Capacity × hours/year
= $(0.70) \times (500 \times 10^3) \times (8760)$
= 3066×10^6 Kwh.

[3]Line (1.) times line (2.).

[4]Derived by deflating line (3.) by 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[5]Derived by escalating line (4.) by 1.8 percent per year between 1977 and 1985, the initial year of plant operation; 1.8 percent represents the real escalation rate of operation and maintenance costs estimated for the period.

Table A-19

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR A LIME FLUE GAS DESULFURIZATION SYSTEM
ON A 500 MW PLANT UTILIZING ANTHRACITE COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars except as noted)

		O & M Costs
1.	Annual O & M Cost in 1980 dollars (mills/Kwh)	2.82[1]
2.	Annual Generation (10^6 Kwh)	3,066[2]
3.	Annual Cost (1980 dollars for operation in 1980)	8,646[3]
4.	Annual Cost (1977 dollars for operation in 1977)	6,960[4]
5.	Annual O & M Cost (1977 dollars for Plant Operation in 1985)	8,028[5]

Table continued on following page.

Table A-19 (Continued)

ANNUAL OPERATION AND MAINTENANCE COSTS
FOR A LIME FLUE GAS DESULFURIZATION SYSTEM
ON A 500 MW PLANT UTILIZING ANTHRACITE COAL
WITH 90 PERCENT REMOVAL
(thousands of dollars except as noted)

Footnotes to Table A-19.

[1]PEDCo. Environmental, Inc., *op. cit.*, p. xxxii.

[2]Annual generation is calculated assuming a 70 percent capacity factor for a 500 MW plant;

$$\begin{aligned}\text{Annual Generation (Kwh)} &= \text{Capacity factor} \times \text{Capacity} \times \text{hours/year}\\ &= (0.70) \times (500 \times 10^3) \times (8760)\\ &= 3066 \times 10^6 \text{ Kwh.}\end{aligned}$$

[3]Line (1.) times line (2.).

[4]Derived by deflating line (3.) by 7.5 percent per year for these years; 7.5 percent is the total escalation rate assumed by PEDCo. in estimating costs in 1980 dollars.

[5]Derived by escalating line (4.) by 1.8 percent per year between 1977 and 1985, the initial year of plant operation; 1.8 percent represents the real escalation rate of operation and maintenance costs estimated for this period.

Appendix B
REPORT ON ANTHRACITE MINING TECHNOLOGIES AND COSTS

Charles Manula[1]

Anthracite seams may be classed as flat, moderately pitching or steeply pitching. The flat seams are those which pitch up to 3 degrees. Moderately pitching seams have pitches from 3 to 30 degrees. Steeply pitching seams begin at 30 degrees and continue up to 90 degrees.

It has been customary to consider anthracite and bituminous mining methods as separate and unrelated. It should be recognized that for any given case the proper method depends on the physical characteristics of the coal seam and the roof and floor, rather than on the rank of the coal itself. A large portion of the anthracite seams that have been worked lie in synclines with steeply pitched sides and the methods of mining that are employed are governed by these pitches, rather than the fact that the coal is anthracite. In contrast to the gently folded to flat lying sedimentary strata that characterize the Appalachian region, many of the anthracite seams are highly folded and faulted and sandwiched between

[1]Prepared by Charles B. Manula, Professor of Mining Engineering, Pennsylvania State University.

metamorphic country rock for the different producing fields. Certain flat anthracite seams are worked in a similar manner to those of the bituminous fields, while the more steeply pitching seams are extracted with methods similar to that applied in deep metal mines.

In this report, the mining technologies used for anthracite mining are described. In addition, cost estimates for mining existing techniques are developed. These costs are based on Pennsylvania mining experience for conditions similar to those hypothesized with coal resource scenarios of this study. All costs are presented in 1978 dollars.

Classification of Mining

For efficient operation, any mining system, both surface and underground, must possess certain basic attributes. The system must have both capacity and reliability to move all the coal that face operations provide without interruption. Equipment and facilities must represent the minimum of investment, be low in maintenance, require minimum operating labor and be safe to use.

A careful study of both face and materials handling problems must include an evaluation of the cost of new and larger operations and equipment. The design factors that need to be considered are the life of the mine, tonnages to be handled, length of roadways, amount of developed workings, mining plans, and possible sizes and construction of equipment. Seam contours, both general and local, also require attention in the selection of methods. Finally, dewatering, refuse disposal and post mining reclamation call for careful consideration. A list of design factors includes the following:

1. Physical shape of the property
2. Available coal reserves
3. Seam contours and grades, both local and general
4. Seam thickness
5. Nature of mine roof and bottom
6. Daily raw coal production
7. Percent of reject
8. Life of mine
9. Mining plan and layout
10. Type of mining equipment
11. Availability of mining equipment
12. Number of daily production shifts
13. Size characteristics and tonnage of rock to be handled
14. Maximum length of haulage system
15. Type of power applied
16. Pumping and treatment
17. Government safety standards

Underground Mining[1]

In working moderately thick or thin beds, lying from horizontal to 10 degrees pitch, it is cutomary to mine the coal in panels which are reached by two gangways. The lower or main gangways serve as intake haulage ways; these entries are preferably driven 18-20 feet wide and of seam height. This method and the standard room-and-pillar one can be readily adapted to mechanized mining (Figure B-1).

Chute breasts are necessary when the pitch of the seam is over 15 degrees, and less than 30 (Figure B-2). In this technique the coal is moved away from the face area through a narrow passageway (chute) in the breast and loaded into mine cars. In seams up to 30 degrees it is necessary to line the bottom of the chute while in those over 30 degrees the coal will flow by gravity alone.

[1]Productivities are estimated at 3.5 tons per man day clean coal.

Figure B–1

ROOM AND PILLAR (12)

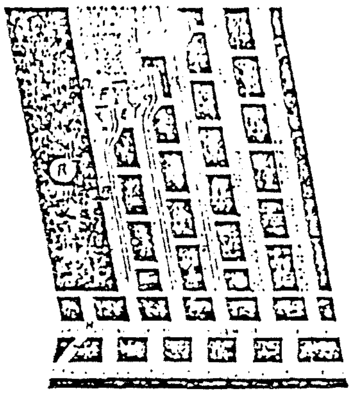


Figure B–2

CHUTE BREAST (12)

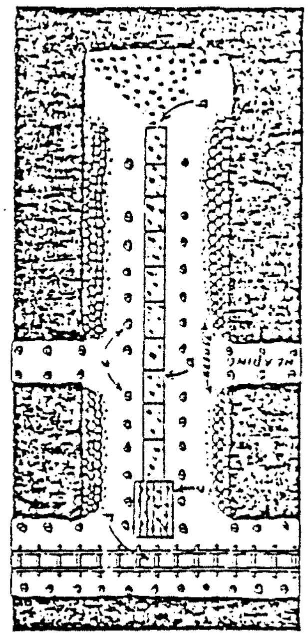
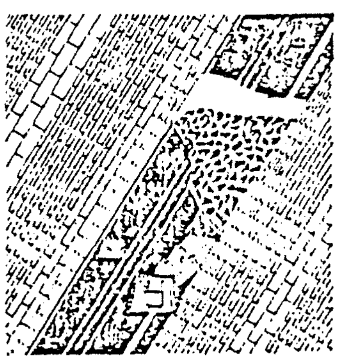


Figure B–3

BATTERY AND BREAST (12)



The change from chute breasts to battery breasts occurs between 30 and 35 degress (Figure B-3). Batteries are used in conjunction with chutes when the pitch varies up to 90 degrees. These batteries provide the necessary means whereby miners can support themselves while working at the face. It is possible to provide a platform which can be advanced as the face advances, but this is an expensive method, and it is generally better to allow the center chute to fill with broken coal and keep the level of this near enough to the face to provide the required standing room. The coal is supported at the mouth of the breast by a bulkhead of heavy timber known as a battery and is referred to as "working on battery." Although single and double battery breasts are the standard underground methods of working pitching anthracite seams, there are many variations of these methods to meet local mining conditions.

Some disadvantages of breast mining include:

1. These are labor intensive systems and require highly trained and skilled practitioners. The availability of manpower is a critical constraint.
2. A soft friable coal when mined on a steep pitch has a tendency to run. One objection is that the running of coal cannot be controlled, and the widths of the breast and pillar cannot be maintained.
3. Working a thick seam of free coal on a heavy pitch requires special precautions to prevent injury to miners.
4. Ventilation control is difficult due to the need to keep airways small for good roof and rib control.

Future Applications

Several new extraction techniques to displace the heavy labor intensive procedures employed in present deep mining practice show promise for future application. Hydraulic coalcutters, augering and boring machines, long wall equipment, along with sub-level caving and coal tap long-holing methods merit serious consideration. Mining equipment research for future anthracite mines including the adaptation of existing methods is a high priority item. Not only production machines, but techniques to support pitches more adequately, need to be developed. Only through increased mechanization can production per man-day be increased to economically viable levels. Since the most advanced of these are at present experimental, they will not be proven technologies in the next ten years -- the time frame of the results of the study -- and hence are not discussed in detail here.

Surface Mining Methods

Stated in the simplest terms, surface mining consists of nothing more than removing the top soil, rock, and other strata that lie above mineral or fuel deposits to recover them. In practice, however, the process is considerably more complex.

When compared with underground methods, surface mining offers distinct advantages. It makes possible the recovery of deposits which, for physical reasons, cannot be mined underground; provides safer working conditions; results in larger resource recoveries; and most important, under favorable conditions it is generally cheaper in terms of cost per unit ton.

Surface mining is not applicable to all situations, however, since the ratio of overburden extracted to mineral produced places a definite economic limitation upon the operator. While this ratio may vary widely owing to differences in the characteristics of the overburden, type and capacity of equipment applied, and in value of the mineral being mined, it is nonetheless the factor that determines whether a particular mining operation can survive in a competitive market.

The procedure for surface mining usually consists of two steps: a) reconnaissance and exploration to locate, delineate and prove the mineral deposit; and b) the actual mining and reclamation phase. Topography and the configuration of the deposit itself strongly influence both. In anthracite deposits, located in Pennsylvania, mining is conducted on hillsides where the coal outcrop is parallel with the mountain crests. Some operations are conducted on natural slopes of more than 10 degrees and the beds themselves vary in pitch up to 90 degrees. Anthracite beds are somewhat thicker than those in the bituminous coal fields, most varying between six and twenty feet, and can be economically mined to much greater depths. Some pits are now operating at depths exceeding 400 feet, and it seems likely that within the next 10 years some large-scale operations may reach depths of 1,000 feet. Because of the angles at which the beds lie, the method employed may not be correctly identified as contour or area mining, but rather a combination of both. In a few instances, the operations may resemble open pits and quarries, while others are long, deep narrow canyons.

Mining Costs

The problem of the inadequate data on Narragansett Basin coal reserves makes it difficult to project method selection and costs. However, we present here some typical costs of mining for the conventional methods described earlier. These costs (in 1978 dollars) are based on experience with Pennsylvania anthracite mining.

Underground Mining Costs

For mining anthracite with proven technologies, three options are suggested -- room and pillar and two methods of breast mining. In this section, we present cost estimates for mining anthracite coal with these methods.

Room and Pillar

Where seams pitch from 0 to 14 degrees room and pillar methods using conventional equipment would be the recommended practice. Estimated productivities (ROM) for the various seam heights and cover are listed in Table B-1. Projected mining costs (excluding capital costs) for ROM are listed in Table B-2. Clean coal costs are estimated based on a reject level of 30 percent and preparation costs of $1.90 for coarse coal cleaning. The capital costs per annual ton are provided in Table B-3. For a 500,000 ton per year mine producing 200 tons per machine section, the estimated capital costs are $30,500,000. These costs are included in Table B-2. They are allocated to output over the life of the mine using indices published by Marshall and Swift in *Mining and Milling*.

Breasts

For seam pitches between 15 degrees and 35 degrees the chute breast with shaker conveyors would apply. Battery breasts are applied for inclined seams between 35 degrees and 90 degrees. For seam thickness of 8 to 14 feet, for either technique, the cost per ROM ton approximates $24. Capital costs per annual ton are insensitive to seam depth in the range 300 to 600 feet and are approximately $15 per annual ton.[1] For a 20 year mine life, and discount rate of 8 percent this results in a total cost per ROM ton of $25.53.

[1]This is based on a conversation with Charles Manula, June 26, 1978.

Table B-1

TONS PER MACHINE SHIFT (TMS)[1]

Depth of Cover	Seam Thickness 4 feet	6 feet	8 feet	10 feet
500	250	370	495	615
1000	240	345	470	550
1500	240	335	380	390

[1]For grades greater than 3 degrees subtract 5 TMS for each 1 degree change.

SOURCE: Charles Manula.

Table B-2

RUN OF MINE MINING COSTS
(1978 dollars)

Tons per Machine Shift	Dollars per Ton ROM	Dollars per Ton Clean
200	27.50	41.20
300	20.50	31.20
400	16.50	25.50
500	14.25	22.30
600	12.50	19.80

SOURCE: Information supplied by Charles Manula.

Table B-3

CAPITAL COST PER ANNUAL TON
(1978 Dollars)

Tons per Machine Shift	Dollars per Annual Ton
200	61
300	40
400	30
500	24
600	21

SOURCE: Charles Manula.

Surface Mining

In this section, we present cost estimates for strip mining which apply for coal at a depth of less than 150 feet. Open pit mining is another technique which can go as deep as 500 feet, but the costs are higher. Tables B-4 and B-5 show costs per ton ROM and capital cost per annual ton as a function of strip ratio.

Clean coal costs are calculated assuming a 70 percent recovery factor and $1.90 cleaning cost per ton of cleaned coal. The capital costs for coal extraction which are included in these ROM figures are given in Table B-5.

Table B-4

RUN OF MINE MINING COSTS
(1978 Dollars)

Strip Ratio[1]	Dollars per Ton ROM	Dollars per Ton Clean Coal
5:1[2]	$ 7.30- 8.50	$12.50-14.00
10:1[2]	13.50-16.50	21.00-25.50
15:1[3]	24.00-30.00	36.00-45.00
20:1[3]	31.00-43.50	46.00-64.00

[1]Cubic yards of waste per ton of ROM coal.

[2]This is for a dragline operation without lift.

[3]This is for a dragline operation with lift.

SOURCE: Information supplied by Charles Manula.

Table B-5

CAPITAL COSTS

Strip Ratios	Dollars per Annual Ton
5:1	10
10:1	22
15:1	38
20:1	52
25:1	80
30:1	108

SOURCE: Charles Manula.

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