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ENVIRONMENTAL DATA ENERGY TECHNOLOGY CHARACTERIZATIONS

Coal

MASTER

U.S. Department of Energy
Assistant Secretary for Environment
Office of Technology Impacts

April 1980

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U.S. Department of Energy

**Assistant Secretary for Environment
Office of Technology Impacts
Washington, DC 20545**

Program Manager: Nevaire M. Serrajian

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OVERVIEW

Environmental Data Energy Technology Characterizations are publications which are intended to provide policy analysts and technical analysts with basic environmental data associated with key energy technologies. The first publication, Summary, provides information in tabular form on the eight technology areas examined; subsequent publications in the series provide more detailed information on the technologies. This publication provides documentation on coal.

The transformation of the energy in coal into a more useful form is described in this document in terms of major activity areas in the coal cycle, that is, in terms of activities which produce either an energy product or a fuel leading to the production of an energy product in a different form. The coal activities discussed in this document are listed in Table 1.

These activities represent both well-documented and advanced coal activity areas. The former activities are characterized in terms of actual operating data with allowance for future modification where appropriate. Emissions are assumed to conform to environmental standards. The advanced coal activity areas examined are those like fluidized-bed combustion and magnetohydrodynamics that are considered promising for mid-term commercialization. For these areas, data from pilot or demonstration plants were used where available; otherwise, engineering studies provided the data.

The organization of the chapters in this publication is designed to support the tabular presentation in the summary volume. Each chapter begins with a brief description of the activity under construction. The standard characteristics, size, availability, mode of functioning, and place in the fuel cycle are presented. Next, major legislative and/or technological factors influencing the commercial operation of the activity are offered. Discussions of resources consumed, residuals produced, and economics follow. To aid in comparing and linking the different activity areas, data for each are normalized to 10^{12} Btu of energy output from the activity.

TABLE 1
MAJOR COAL ACTIVITY AREAS EXAMINED

Coal Mining

Surface - Eastern

Surface - Western

Underground - Eastern

Coal Beneficiation

Coal Power Plant

Conventional Boiler - Eastern Coal

Conventional Boiler - Western Coal

Fluidized Bed Combustion - Bituminous Coal

Fluidized Bed Combustion - Western Subbituminous Coal

Magnetohydrodynamic System

Coal-Oil Mixture

Coal Transportation

Unit Train - Eastern

Unit Train - Western

Conventional Train - Eastern

Conventional Train - Western

Barge

Truck

Slurry Pipeline

Transmission Lines

High Voltage

Very High Voltage

Note: This list is not intended to be exhaustive at this time. It will be extended in future revisions to this document.

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1.0 INTRODUCTION

This document describes the activities leading to the conversion of coal to electricity. Specifically, the activities consist of coal mining and beneficiation, coal transport, electric power generation, and power transmission. Table 1-1 identifies the representative sizes of the activity areas considered here.

To enhance the usefulness of the material presented, resource requirements, energy products, and residuals for each activity area are normalized in terms of 10^{12} Btus of energy produced. Thus, the total effect of producing electricity from coal can be determined by combining the residuals associated with the appropriate activity areas.

Emissions from the coal cycle are highly dependent upon the type of coal consumed as well as the control technology assigned to the activity area. Each area is assumed to be equipped with currently available control technologies that meet environmental regulations. The conventional boiler, for example, has an electrostatic precipitator and a flue gas desulfurization scrubber. While this results in the removal of most of the particulate matter and sulfur dioxide in the flue gas stream, it creates other new environmental residuals--solid waste, sludge, and ash.

There are many different types of mined coal. For informational purposes, two types from two major producing regions, the East and the West, are characterized here. The eastern coal is typical of the Northern Appalachian coal district with a high sulfur and heat content. The western coal, from the Powder River Basin, has much less sulfur, but also has a substantially lower heating value. The composition of coal varies by region as shown in Table 1-2 (McGraw-Hill, 1978).

TABLE 1-1

RELATIVE SIZE OF COAL FUEL CYCLE BASE UNITS

BASE UNIT	SIZE ANNUAL PRODUCTION	EQUIVALENT BTU ANNUAL PRODUCTION
Coal Mining		
Surface		
Eastern	4 x 10 ⁶ tons	100 x 10 ¹²
Western	6 x 10 ⁶ tons	110 x 10 ¹²
Underground		
Eastern	2 x 10 ⁶ tons	50 x 10 ¹²
Coal Beneficiation	2 x 10 ⁶ tons	55 x 10 ¹²
Coal Power Plant*		
Conventional Boiler		
Western Coal	500 MWe	8.2 x 10 ¹²
Eastern Coal	500 MWe	8.2 x 10 ¹²
Fluidized Bed Combustion (Bituminous Coal)	878 MWe	15.8 x 10 ¹²
Fluidized Bed Combustion (Western Subbituminous Coal)	600 MWe	15.2 x 10 ¹²
Magnetohydrodynamic System	1932 MWe	37.5 x 10 ¹²
Transportation		
Unit Train		
Western	900,000 tons	17 x 10 ¹²
Eastern	945,000 tons	24 x 10 ¹²
Conventional Train		
Western	18,900 tons	0.4 x 10 ¹²
Eastern	18,900 tons	0.5 x 10 ¹²
Slurry Pipeline	25 x 10 ⁶ tons	4.7 x 10 ¹²
Transmission**		
High Voltage	345 KV	9.6 x 10 ¹²
Very High Voltage	500 KV	20.8 x 10 ¹²

*Load factors vary among different types of power plants.

**Transmission line efficiencies vary with voltage and distance; the high voltage line is 82 percent efficient, the very high voltage line is 89 percent efficient.

TABLE 1-2
REPRESENTATIVE COAL ANALYSES

COMPONENT	TYPICAL NORTHERN APPALACHIAN COAL	TYPICAL POWDER RIVER BASIN COAL
moisture	3.9%	21.5%
volatile matter	34.1%	34.5%
fixed carbon	52.4%	39.6%
ash	9.6%	4.4%
sulfur	2.1%	0.4%
nitrogen	1.1%	1.2%
heat content	12,850 Btu/lb	9,450 Btu/lb

Source: McGraw Hill Informational Mining Services, 1978. Keystone Coal Industry Manual. McGraw-Hill, Inc. Publishers, New York, NY.

1.1 References

McGraw Hill Mining Informational Services, 1978. Keystone Coal Industry Manual. McGraw-Hill, Inc. Publishers, New York, NY.

2.0 SURFACE COAL MINING

2.1 Characteristics of Surface Coal Mining

Surface mining is currently the predominant means to recover coal. The percent of coal recovered by surface mining has increased from less than 10 percent in 1930 to more than 50 percent in 1973 (University of Oklahoma, 1975).

The two major methods of surface coal mining are contour and area strip mining. Contour strip mining is used in hilly terrain (slopes greater than 15°) and involves the removal of the coal seam from the contoured bench or "highwall". Area mining is used in flat terrain and involves digging parallel trenches to expose the coal deposit.

Although specific activities practiced at contour and area strip mines differ (Chironis, 1978), the major tasks are the same, namely, surface preparation, fracturing, overburden removal, coal extraction, transport, and land reclamation. Surface preparation includes the removal of any surface obstacles (e.g., vegetation) and initiates the construction of roads and facilities. Fracturing involves blasting to fragment the earth to ease the mining. Immediately following the removal of this fragmented "overburden", the coal is extracted and loaded (into trucks, barges, railway cars, and slurry pipelines) for transport. The final task consists of: grading the spoil banks to approximate the original landform, replacing the topsoil, and restoring the vegetative cover. Table 2-1 shows the efficiency of surface mining by region (Hittman, 1974). Table 2-2 lists the type and quantity of major mining equipment used during specific activities at representative eastern and western area strip mines (Katell et al., 1976). (For this version of Volume III, contour area mining is not discussed.)

TABLE 2-1

PERCENT OF COAL EXTRACTED FROM AREA SURFACE MINES

REGION	BTU EXTRACTED AS A FRACTION OF TOTAL BTU POTENTIALLY AVAILABLE
Northern Appalachian (PA, OH, northern WV)	80-81*
Central Appalachian (TN, southern VA, KY)	80
Midwest (IL, IN)	81
High Plains (MN, WY)	89
Southwest (NM)	81
National	80-81*

*Lower figure is for a slope greater than 15 degrees; higher figure is for a slope less than 15 degrees.

Source: Hittman Associates, Inc., 1974. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I. HIT-593. Columbia, Maryland.

TABLE 2-2

EQUIPMENT USED DURING AREA SURFACE MINING

ACTIVITY	TYPICAL EASTERN AREA MINE (4 x 10 ⁶ T/YR)		TYPICAL WESTERN AREA MINE (6 x 10 ⁶ T/YR)	
	Equipment	Quantity	Equipment	Quantity
Surface preparation, roads, and reclamation	Bulldozer	4	Bulldozer	6
	Tractor-scraper	4	Tractor-scraper	6
	Grader	2	Grader	2
Working the overburden	Drill	4	Drill	4
	Bulldozer	4	Bulldozer	6
	Stripping shovel (100 yd ³)	2	Tractor-scraper	2
			Dragline (45 yd ³)	2
Coal Loading	Coal shovel (15 yd ³)	2	Drill	2
	Front-end loader (15 yd ³)	2	Shovel (15 yd ³)	2
	Truck (120 T)	7	Front-end loader (15 yd ³)	2
			Truck (120 T)	11

Source: Katell, Sidney, et al., 1976. Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines. U.S. Bureau of Mines, Information Circular 8703. U.S. Government Printing Office, Washington, D.C.

2.2 Surface Coal Mining Constraints

According to the University of Oklahoma (1975), "until about 1965, surface mining of coal was not considered feasible unless the overburden-to-seam thickness ratio was 10:1 or less. Thus, to justify removing 50 feet of overburden, the coal seam would have to be five or more feet thick. Since 1965, the ratio has been increasing and most coal within 150 feet of the surface is now considered economically recoverable, even when the overburden-to-seam thickness ratio is as much as 30:1."

Legislation also affects surface mining. The Surface Mining Control and Reclamation Act (SMCRA) (PL 95-87) influences where coal can be mined and sets national minimum mining and reclamation standards. States may enforce the provisions of this legislation, and strengthen it if they so desire, providing they meet minimum requirements. The Occupational Safety and Health Act (OSHA) (PL 91-596) regulates health and safety conditions in the industry.

Procedures to control the leasing of federal land for coal mining are set out in the Federal Land Policy & Management Act (PL 94-597), and the Minerals Leasing Act (PL 66-146). These procedures are particularly important in the West, where there is a great deal of Federally owned coal-bearing land. Coal mining in designated wilderness areas is severely limited by the Wilderness Act (PL 88-577). The Wild and Scenic Rivers Act (PL 90-542) prohibits coal operations from reducing the quality of designated scenic rivers and wildlife habitats.

Surface coal mining may also be affected by the National Environmental Policy Act (NEPA), (PL 91-190). NEPA requires the preparation of an environmental impact statement for major Federal

activities having a significant impact on the human environment. The Clean Air Act (CAA) (PL 91-604) sets emission and ambient air quality standards. Its most important impact on surface coal mining may be on the emission of particulate matter by coal mining operations.

The Clean Water Act of 1977 regulates the discharge of pollutants into navigable waters. The Safe Drinking Water Act (PL 93-523) affects any coal mine that might contaminate a drinking water source. The Fish and Wildlife Coordination Act (PL 85-624) requires a review to minimize any damage to fish and wildlife caused by water pollution.

Solid waste management was promoted by the Solid Waste Disposal Act (PL 91-512). Solid waste from mines is now regulated by the Resource Conservation and Recovery Act (RCRA) (PL 94-580).

2.3 Resource Requirements

The major resources needed for surface coal mining are land, water, auxiliary power (the energy expended to extract the coal), labor, and capital. As can be seen in the following tables, there is considerable regional variation in resource requirements. Factors that contribute to this variation include, but are not limited to: stripping ratios, mining methods, seam thicknesses, terrain features, water availability, and types of equipment. The following discussion summarizes the bases utilized to compute the resource requirements for typical eastern and western area strip mines.

2.3.1 Auxiliary Power

Auxiliary power consumption by strip mines consists of electricity and diesel fuel use. Data on electricity use for typical

surface mines were taken from Hittman (1974). According to Jarman et al. (1979), diesel fuel and gasoline consumption at surface mines account for about two-thirds of the expended energy; the remainder is in the form of electrical energy. Table 2-3 provides data on auxiliary energy needs for eastern and western area surface mines per 10^{12} Btu produced.

TABLE 2-3
TYPICAL ELECTRICITY AND DIESEL FUEL DEMANDS
BY EASTERN AND WESTERN AREA SURFACE MINES
(Per 10^{12} Btu Produced)

LOCATION	DIESEL FUEL* (x 10^9 Btu)	ELECTRICITY (x 10^5 kWh)
Northern Appalachian	4.0	5.9
Powder River Basin	0.8	1.1

*Computed value according to Jarman et al.'s observation.

As can be seen, there is considerable regional variation over the amount of auxiliary energy consumed. One factor contributing to this difference is the variation of the stripping ratio in the two regions. The stripping ratio in the Northern Appalachian Coal District is about seven times that generally encountered in the Powder River Basin (i.e., 16.7:1 vs. 2.3:1). Moreover, the terrain in the Northern Appalachian Coal District is more complex than that found in the Powder River Basin (i.e., slopes averaging $5^\circ - 15^\circ$ vs. $1^\circ - 5^\circ$). As the complexity of the terrain increases the activities devoted to mining and reclamation must intensify.

2.3.2 Land

The magnitude of property needed to support surface mining is shown in Table 2-4. As shown, a western surface mine disturbs much less land per Btu output than an eastern surface mine. This is because the thickness of coal seams in the West greatly exceeds those located in the East (e.g., seam thickness in the Northern Appalachian Coal District average about six feet and the thickness of a typical Powder River Basin Coal District seam is greater than 30 feet).

2.3.3 Water

Another resource essential for surface coal mining is water which is used during mining operations and for dust suppression and reclamation. Water consumption data for typical Northern Appalachian and Powder River Basin coal mines is shown in Table 2-5.

The water demand in the West exceeds that in the East because of the greater need for dust suppression in the West.

2.3.4 Capital

Representative construction and operating costs for eastern and western area strip mines are shown in Table 2-6. Although construction costs for eastern and western area strip mines are comparable, operating costs differ significantly. Operating costs in the West are lower than those in the East because mining in the West occurs over flat terrain and includes the removal of less overburden. In addition, the cost of reclamation in the East typically averages \$1.00 per ton vs. only \$0.10 per ton in the Northern Great Plains (Mann and Heller, 1979).

TABLE 2-4

LAND REQUIREMENTS FOR AREA STRIP MINES

	FIXED LAND (permanently committed)	INCREMENTAL (temporarily committed)
Eastern area mine: (6 foot seam)		
Acres for 4×10^6 T/YR*	30	625
Acres for 10^{12} Btu**	0.3	6.1
Western area mine: (30 foot seam)		
Acres for 6×10^6 T/YR*	45	200
Acres for 10^{12} Btu**	0.4	1.8

*Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, California.

**Computed value assuming heat content of eastern coal equals 25.7×10^6 Btu/Ton and western coal equals 18.9×10^6 Btu/Ton.

TABLE 2-5

WATER CONSUMPTION FOR TYPICAL NORTHERN APPALACHIAN
AND POWDER RIVER BASIN STRIP MINES

	WATER MAKE-UP
<hr/>	
Northern Appalachian (PA)	
Acre-feet for 10^5 T*	4.46
Acre-feet for 10^{12} Btu**	1.7
Powder River Basin (WY)	
Acre-feet for 10^5 T*	5.7
Acre-feet for 10^{12} Btu**	3.0
<hr/>	

*U.S. Department of the Interior, Bureau of Land Management, 1979.
Final Environmental Statement, Federal Coal Management Program.
Washington, D.C.

**Computed value assuming heat content of Northern Appalachian coal
equals 25.7×10^6 Btu per ton and Powder River Basin coal equals
 18.9×10^6 Btu per ton.

TABLE 2-6

CAPITAL AND OPERATING COSTS FOR EASTERN AND WESTERN AREA MINES
(in 1977 Dollars)

	CONSTRUCTION COST				OPERATING COST	
	Manpower	Material	Equipment	Other Investments	General Mining Cost	Reclamation and Sedi-ment Control
Eastern Area Mine						
(6 foot seam)						
\$ x 10 ⁶ for 4 x 10 ⁶ T/YR*	17.7	3.2	106.8	69.7	--	--
\$ x 10 ⁵ for 10 ¹² Btu***	1.7	0.3	10.4	6.8	--	--
\$ for 1 T**	--	--	--	--	11.75	0.7
\$ x 10 ⁵ for 10 ¹² Btu***	--	--	--	--	4.6	0.3
Western Area Mine						
(30 foot seam)						
\$ x 10 ⁶ for 6 x 10 ⁶ T/YR*	11.5	2.7	136.0	25.8	--	--
\$ x 10 ⁵ for 10 ¹² Btu***	1.0	0.2	12.0	2.3	--	--
\$ for 1 T**	--	--	--	--	5.38	0.04
\$ x 10 ⁵ for 10 ¹² Btu***	--	--	--	--	2.8	0.02

* Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, California.

** Energy and Environmental Analysis, Coal and Profitability, 1979.

*** Computed value assuming heat content of eastern coal equals 25.7×10^6 Btu per ton and western coal equals 18.9×10^6 Btu per ton.

2.3.5 Personnel

Manpower requirements for construction and operation were derived from Bechtel (1978) and are shown in Table 2-7.

By way of comparison, Bureau of Mines (Katell, et al., 1976) data imply only about 1.5 workers per 10^{12} Btu output for Eastern operating levels and 1.3 workers per 10^{12} Btu output for Western operating levels. The discrepancy between the two data bases is probably due to the fact that the Bureau's 1975 data do not reflect the manpower levels that are required to meet SMCRA requirements.

2.4 Residuals

Surface mining creates air pollution, water pollution, and solid waste. Table 2-8 presents data on these pollutants.

The two major sources of air pollution in strip mining are diesel-powered vehicles and fugitive dust sources. There is more potential for fugitive dust in the West due to drier climate and slower revegetation cycles. In addition, a greater percentage of the equipment used in the West is electric as opposed to diesel (Chironis, 1978). This explains why the values for the other listed air pollutants are higher in the East than the West.

Water pollution is due to refuse pile runoff and mine drainage. In the East, water discharge is acidic; in the West it is alkaline. Discharges of suspended solids are higher in Appalachia than in the West mainly because of the larger areas of downslope overburden in the East.

TABLE 2-7

PERSONNEL REQUIREMENTS FOR SURFACE COAL MINING

	CONSTRUCTION			OPERATION		
	nonmanual, technical	nonmanual, nontechnical	manual	nonmanual, technical	nonmanual, nontechnical	manual
Eastern Area Mine						
Output: (4×10^6 T/YR, 6 foot coal seam)						
man hours $\times 10^3$ *	209	32	970	--	--	--
man years *	--	--	--	83.4	113.1	249.1
man years per 10^{12} Btu **	1.0	0.2	4.7	0.8	1.1	2.4
Western Area Mine						
Output: (6×10^6 T/YR, 30 foot seam)						
man hours $\times 10^3$ *	254	37	503	--	--	--
man years *	--	--	--	77.4	99.5	214.6
man years per 10^{12} Btu **	1.1	0.2	2.2	0.7	0.9	1.9

* Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, California.

** Computed value assuming heat content of Eastern coal is 25.7×10^6 Btu per ton and 18.9×10^6 Btu per ton for the West. In addition, it was assumed that 2,000 man hours is equivalent to one man year.

TABLE 2-8
SURFACE COAL MINING RESIDUALS
(Per 10¹² Btu Produced)

	<u>EASTERN STRIP MINE</u>		<u>WESTERN STRIP MINE</u>	
	Gross Tons	Net Tons	Gross Tons	Net Tons
<u>Air Pollutants</u> ⁽¹⁾				
HC	0.2	0.2	0.2	0.2
CO	0.9	0.9	1.2	1.2
SO _x	0.1	0.1	0.2	0.2
NO _x	1.5	1.5	2.0	2.0
PM ⁽²⁾	0.06	0.02	0.2	0.08
<u>Water Pollutants</u> ⁽³⁾				
TDS	35.6	20.8	90.9	23.9
Fe	0.4	0.0004	0.005	0.005
Mn	0.4	0.1	0.02	0.02
Al	0.6	0.03	0.006	0.006
Zn	0.02	0.002	0.005	0.005
Ni	0.006	0.002	0.001	0.001
TSS	4.8	0.4	3.0	2.3
Fe	0.02	0.004	0.02	0.02
NH ₃	0.06	0.02	0.1	0.2
SO ₄	16.1	14.3	41.1	32.7
<u>Solid Waste</u> ⁽⁴⁾				
From overburden removal	435	0	745	0
From mine water runoff treatment	390	0	NA	0

- (1) U.S. Department of the Interior, Bureau of Land Management, 1979. Final Environmental Statement, Federal Coal Management Program. Washington, D.C.
- (2) Assumes that a 60% reduction in particulate emissions can be achieved through dust suppression techniques.
- (3) The MITRE Corporation, 1977. Annual Environmental Analysis Report, Volume IV (Draft). McLean, Virginia.
- (4) Hittman Associates, Inc., 1974. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Volume I. HIT-593. Columbia, Maryland.

When an operator includes a process to mitigate water pollution, an additional 50 to 150 tons of solid waste (sludge) per 10^{12} Btu are generated. However, since all solid wastes from surface mines are returned to the mined out pits, net solid waste residuals are zero. (This does not mean that measures may not be required to control leaching.)

2.5 References

- Bechtel Corp., 1978. Energy Supply Planning Model. San Francisco, California.
- Chironis, Nicholas P., ed., 1978. Coal Age Operating Handbook of Coal Surface Mining and Reclamation. Coal Age Mining Informational Services, McGraw-Hill, Inc., New York, N.Y.
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- U.S. Department of the Interior, Bureau of Land Management, 1979. Final Environmental Statement, Federal Coal Management Program. Washington, D.C.

3.0 UNDERGROUND COAL MINING

3.1 Characteristics of Underground Coal Mining

The two main methods to mine coal underground are room-and-pillar and longwall. However, in the U.S., the room-and-pillar mining method is used much more extensively than longwall mining; longwall accounts for only about four percent of U.S. underground coal production (National Coal Association, 1975).

During room-and-pillar mining, rooms are formed while mining the coal. Portions of the coal seam are left standing as pillars to prevent the roof from collapsing. There are three major alternative practices to recover the coal from the seam and load it onto mine transport equipment:

- machine cutting (coal seam breakup) and hand loading
- conventional mining, which uses machine cutting and mechanical loading
- continuous mining, in which one machine performs the cutting and loading operations

Most room-and-pillar mines now employ either conventional or continuous mining methods (University of Oklahoma, 1975). According to Hittman (1974), about 57 percent of the coal in a seam mined by the room-and-pillar method is actually extracted. Table 3-1 lists the types of equipment that may be used in continuous room-and-pillar mining.

Longwall mining uses a shearing drum to cut coal from the seam's working face between two access passageways or galleries.

TABLE 3-1

TYPE AND QUANTITY OF EQUIPMENT USED FOR UNDERGROUND
CONTINUOUS ROOM-AND-PILLAR COAL MINING
(2 x 10⁶ Ton Per Year)

COMPONENT	QUANTITY
mainline belt conveyor	1
roof bolting machine	13
ventilating fan	1
auxiliary fans	13
continuous mining machines	11
pumps	11
loading machines	11
shuttle car	22
ratio feeder	11
rock duster	12
supply motor	5
mainline belt power center	5
section belt power center	7
section rectifier	11
rectifier for track haulage	2

Note: For longwall mining, the same equipment would be used with some minor exceptions. In particular, longwall mining units would be used in lieu of continuous mining machines, and roof bolting machinery may not be required.

Source: Katell, Sidney, et al., 1974. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines, Mines With Annual Production of 1.06 to 4.99 and 1.03 to 3.09 Million Tons from a 72-Inch and 48-Inch Coal Bed. Information Circulars 8632 and 8641, respectively. U.S. Government Printing Office: Washington, D.C.

Sheared coal drops onto a conveyor which moves it to the transportation system to remove the coal from the mine. The roof immediately behind the mining machine is held up by hydraulic jacks that are moved forward as the mining operation advances. As the jacks are moved, the roof in the area from which the coal has been mined is allowed to collapse. Roughly 85 percent of the coal in a seam mined by the longwall method is actually extracted (Hittman, 1974).

For both types of underground mining, the initial step is to clear vegetation from the site, construct access roads and facilities, bring the necessary utilities to the site, and locate entry tunnels or shafts. The coal deposit is reached by digging or boring a vertical shaft or a horizontal (or slanting) entry. Only after the deposit is reached do differences in the mining practices occur.

Table 3-2 depicts sample proximate analysis for coal belonging to Northern Appalachia (McGraw-Hill, 1977). There are some underground mines in the West, but the overwhelming majority are in the East.

3.2 Underground Coal Mining Constraints

A considerable number of legal constraints affect underground coal mining. The Federal Coal Mine Health & Safety Act (PL 91-173 and subsequent amendments) sets safety standards for the industry and authorizes the promulgation of new regulations as conditions warrant. The Surface Mining Control and Reclamation Act (PL 95-87), although primarily concerned with surface mining, calls for minimizing subsidence resulting from underground mining (U.S. Department of Energy, 1978).

Procedures to control the leasing of Federal land for coal mining are set forth in the Federal Land Policy & Management Act (PL

TABLE 3-2

COAL ANALYSIS - NORTHERN APPALACHIAN COAL DISTRICT

COAL ANALYSIS	PERCENT BY WEIGHT
moisture	3.9
volatile matter	34.1
fixed carbon	52.4
ash	9.6
sulfur	2.1
nitrogen	1.1
heat content	12,850 Btu/lb

Source: McGraw-Hill Mining Information Services, 1977. Keystone Coal Industry Manual. McGraw-Hill, Inc., Publishers. N.Y., N.Y.

94-597) and the Minerals Leasing Act (PL 66-146). These procedures are particularly important in the West, where there is much Federally owned coal-bearing land. Coal mining in designated wilderness areas is severely limited, if not completely forbidden, by the Wilderness Act (PL 88-577). The Wild & Scenic Rivers Act (PL 90-542) prohibits coal operations from reducing the quality of designated scenic rivers and wildlife habitats.

Underground coal mining may also be affected by the National Environment Policy Act (PL 91-190) which requires the preparation of an Environmental Impact Statement for major Federal activities having a significant impact on the environment.

The Federal Water Pollution Control Act (PL 92-500) regulates the discharge of pollutants into navigable waters. The Safe Drinking Water Act (PL 93-523) affects any coal mine that might contaminate a drinking water supply. The Fish & Wildlife Coordination Act (PL 85-624) requires a review to minimize any damage to fish and wildlife caused by water pollution.

Solid waste management is promoted by the Solid Waste Disposal Act (PL 91-512). Solid waste from mines is also regulated by the Resource Conservation & Recovery Act (PL 94-580).

3.3 Resource Requirements

The major resource requirements for underground coal mining are land, water, auxiliary energy, labor, and capital. The following discussion summarizes the bases utilized to compute the resource demands for a typical eastern continuous room-and-pillar mine that has a recovery efficiency of 57 percent.

3.3.1 Auxiliary Energy

The need for electricity by underground mines forms the bulk of its energy demand. Hittman (1974) estimates that 7.2×10^5 kWh are used for every trillion Btu of coal extracted in Northern Appalachia. For comparison, Bechtel (1978) indicates that 1.04×10^6 dollars of electricity are expended annually to mine two million tons of coal. Given that one dollar purchases about 30 kWh and the heat content of coal is 25.7×10^6 Btu per ton, use of Bechtel's data yields about 5.6×10^5 kWh to recover 10^{12} Btu of coal in the East.*

3.3.2 Land

The amount of surface land needed to support an underground mine was given by Bechtel (1978). They estimate that 15 acres of surface land will be permanently disturbed and 600 acres temporarily disturbed per year will be needed for a two million ton per year Eastern underground mine. Assuming that the heat content of the mined coal is 25.7×10^6 Btu per ton, these data suggest that 0.3 acres of permanently disturbed land and 11.7 acres of temporarily disturbed land are required by an underground mine to recover 10^{12} Btu of coal.

3.3.3 Water

Water, which is used during mining operations and dust suppression, is another resource essential to underground coal mining. Water consumption by underground mines in Northern Appalachia have been estimated by the U.S. Department of the Interior (1979) at 5.9 acre-feet per 100,000 tons of coal mined. Assuming that the heat

*Bechtel does not indicate costs per kWh.

content of the mined coal is 25.7×10^6 Btu per ton, these data suggest that 2.3 acre-feet of water is needed to recover 10^{12} Btu of coal. For comparison, Bechtel (1978) indicates that 400 acre-feet per year are required by a two million ton per year mine. Assuming the above cited heat content for the coal, Bechtel's data suggest that 7.8 acre-feet will be used to obtain 10^{12} Btu of coal. (This analysis does not assume any contributions are made due to mine dewatering which could be substantial in specific instances.)

3.3.4 Capital

Representative construction and operating costs for a two million ton per year eastern underground coal mine (having a five foot seam and a 57 percent recovery) were estimated by Bechtel (1978). These data are reproduced in Table 3-3.

By comparison, the Bureau of Mines (Katell et al., 1974) has also compiled construction and operating costs for differently sized underground mines. Their data are given in Table 3-4.

3.3.5 Personnel

Bechtel's (1978) data on construction and operation manpower requirements are shown in Table 3-5. For comparison, Bureau of Mines (Katell et al., 1974) data are shown in Table 3-6.

3.4 Residuals

In terms of residuals evident at the mine mouth, underground mining mainly creates water pollution and solid waste. Air pollution is not necessarily a problem since most equipment used at underground mines is powered by electricity that is generated at remote sources.

TABLE 3-3

CAPITAL AND OPERATING COSTS FOR AN EASTERN UNDERGROUND COAL MINE
(in 1977 Dollars)

	CONSTRUCTION COST				OPERATING COST (excluding fuel)			
	Manpower	Material	Equipment	Other Investments	Manpower	Material	Equipment	Other Costs
Eastern Underground Mine								
\$ x 10 ⁶ for 2 x 10 ⁶ T/Yr*	8.7	5.7	19.5	36.4	25.0	3.9	7.2	18.6
\$ x 10 ⁵ for 10 ¹² Btu**	1.7	1.1	3.8	7.1	4.9	0.8	1.4	3.6

* Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, California.

** Computed value assuming heat content of eastern coal equals 25.7 x 10⁶ Btu per ton.

TABLE 3-4
UNDERGROUND COAL MINING PRODUCTION COSTS
(in 1973 Dollars)

SEAM THICKNESS	MINE OUTPUT 10 ⁶ T/YR	CAPITAL INVESTMENT		OPERATING COSTS	
		\$/T	\$ x 10 ⁶ per 10 ¹² Btu*	\$/T	\$ x 10 ⁶ per 10 ¹² Btu*
48-inch coal seam	1.03	20.09	(7.8)	7.60	(3.0)
	2.06	17.61	(6.9)	6.97	(2.7)
	3.09	16.83	(6.5)	6.81	(2.6)
72-inch coal seam	1.06	20.62	(8.0)	7.35	(2.9)
	2.04	17.47	(6.8)	6.77	(2.6)
	3.18	15.87	(6.2)	6.50	(2.5)
	4.99	15.15	(5.9)	6.45	(2.5)

*Computed value assuming the heat content of the mined coal is 25.7 x 10⁶ Btu/T.

Source: Katell, Sidney et al., 1974. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines, Mines With Annual Production of 1.06 to 4.99 and 1.03 to 3.09 Million Tons with a 72-Inch and 48-Inch Coal Bed. Information Circulars 8632 and 8641, respectively. U.S. Government Printing Office, Washington, D.C.

TABLE 3-5

PERSONNEL REQUIREMENTS FOR EASTERN UNDERGROUND COAL MINES

	CONSTRUCTION			OPERATION		
	nonmanual, technical	nonmanual, nontechnical	manual	nonmanual, technical	nonmanual, nontechnical	manual
Eastern Underground Mine						
Output: (2 x 10 ⁶ T/Yr; 60-inch seam)						
man hours x 10 ³ *	135.0	15.0	446.0	--	--	--
man years*	--	--	--	202.9	266.4	639.7
men per 10 ¹² Btu**	1.3	0.1	4.3	3.9	5.2	12.4

*Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, California.

**Computed value assuming the heat content of the coal is 25.7 x 10⁶ Btu/ton.

TABLE 3-6

UNDERGROUND COAL MINE OPERATING MANPOWER LEVELS

SEAM THICKNESS	OUTPUT	PRODUCTION PERSONNEL		SUPERVISORY PERSONNEL	
	10 ⁶ T/YR	men*	men per 10 ¹² Btu**	men*	men per 10 ¹² Btu**
48" seam	1.03	210	(7.9)	44	(1.7)
	2.06	402	(7.6)	59	(1.1)
	3.09	600	(7.6)	74	(0.9)
72" seam	1.06	200	(7.3)	43	(1.6)
	2.04	369	(7.0)	56	(1.1)
	3.18	558	(6.8)	71	(0.9)
	4.99	882	(6.9)	109	(0.8)

*Katell, Sidney et al., 1974. Basic Estimated Capital Investments and Operating Costs for Underground Bituminous Coal Mines, Mines With Annual Production of 1.06 to 4.99 and 1.03 to 3.09 Million Tons From a 72-Inch and 48-Inch Coal Bed. Information Circulars 8632 and 8641, respectively. U.S. Government Printing Office, Washington, D.C.

**Computed value assuming heat content of coal is 25.7×10^6 Btu/Ton.

Other activities at the surface such as vehicle operations, coal handling, and road dust are important air polluters but they are considered highly site specific and are not estimated here.

Table 3-7 offers data on the residuals emerging from underground mining. One of the main water pollution problems associated with eastern underground mines is acid drainage. This problem can, however, be mitigated with lime. Suspended solids result mostly because of runoff from the solid waste piles.

The amount of solid waste produced by sinking the initial shaft for a typical underground mine is small, about 3000 tons (University of Oklahoma, 1975). (The basis for this estimate has not been substantiated so it is not included in Table 3-7.) A substantial amount of solid waste could be generated during the treatment of mine water but because the subject mine dewatering is not quantified here, the amount of solid waste associated with it is not either. A significant amount of solid waste may also be produced by mining "roof rock", "bottom rock" and "partings". The amount of this non-coal matter that is extracted (to gain sufficient working height) may in some cases equal the weight of the coal mined for thinner seams (3 or 4 feet). This type of waste is a relatively negligible factor for thicker seams (8 to 9 feet) (Wilson, 1979).

3.5 References

- Bechtel Corp., 1978. Energy Supply Planning Model. San Francisco, California.
- Hittman Associates, Inc., 1974. Environmental Impacts, Efficiency and Cost of Energy Supply and End Use, Volume I. HIT-593. Columbia, Maryland.

TABLE 3-7
UNDERGROUND COAL MINING RESIDUALS
(In Tons per 10^{12} Btu)

	GROSS	NET
Water Pollutants ⁽¹⁾		
TDS	396.4	392.0
Fe	22.4	0.02
Mn	0.6	0.1
Al	3.6	1.7
Zn	0.1	0.02
Ni	0.06	0.02
Sr	0.2	0.2
Cl ⁻	8.6	12.7
Fl ⁻	0.1	0.1
CaCO ₃ (2)	101.7	138.3
TSS	19.0	1.7
Fe	7.0	0.2
NH ₃	1.0	0.3
SO ₄	197.8	174.9
Solid Waste ⁽³⁾		
From sinking the mine shaft ⁽⁴⁾	58	58
From treating the mine water runoff ^(4,2)	0	2090

(1) MITRE Corporation, 1977. Annual Environmental Analysis Report (Draft), AEAR IV. McLean, Virginia.

(2) Net emissions of CaCO₃ exceeds the gross because this substance is added to the waste water during the treatment process.

(3) Data is subject to an error up to 50%.

(4) Hittman Associates, Inc., 1974. Environmental Impacts, Efficiency and Costs of Energy Supply and End Use, Volume I, HIT-593. Columbia, Maryland.

Katell, Sidney, et al., 1974. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines, Mines With Annual Production of 1.06 to 4.99 and 1.03 to 3.09 Million Tons From a 72-Inch and 48-Inch Coal Bed. Information Circulars 8632 and 8641, respectively. U.S. Government Printing Office, Washington, D.C.

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4.0 COAL BENEFICIATION

4.1 Characteristics of Coal Beneficiation

Coal beneficiation, also called coal cleaning or coal preparation, is a process whereby raw coal is sized and impurities such as sulfur and ash are reduced. Coal which is sized but has not had its impurities removed is not beneficiated. The level at which coal undergoes beneficiation depends on the type of coal being handled and its ultimate use. In general, more intense beneficiation is applied to coal used in metallurgy than to coal used to generate electricity.

Almost all coal mined in the U.S. is sized before being used; about half is beneficiated. Cleaned coal is termed metallurgical if it will be used in the metals industry, principally in producing steel, or steam coal if it will be combusted to generate electricity or industrial process heat. In 1975, about 54 percent of cleaned coal was steam coal used for utility purposes and 46 percent was metallurgical.*

*The split was calculated as follows: In 1975, U.S. utilities consumed 403,249,000 tons of coal (U.S. Department of the Interior 1977); forty percent of this coal was cleaned. Therefore, 161,300,000 tons of coal were cleaned for utility use.

In 1975, 82,147,000 tons of coal were consumed by oven coke plants and 1,125,000 tons were consumed by beehive coke plants (U.S. Department of the Interior, 1977). It is assumed that all of this coal is classified as metallurgically cleaned coal. An additional 65,669,000 tons of coal were exported. Eighty five percent of the export is assumed to be metallurgically cleaned coal (MITRE, 1977). Therefore, 139,091,000 tons of coal were cleaned for metallurgical use in 1975. This split does not include any cleaned coal used for purposes other than for metallurgy and utility use. A split of 54 percent utility and 46 percent metallurgical coal is derived.

Phillips and DeRienzo's (1977) levels of coal preparation are reproduced in Table 4-1. The level to be modeled here is E, a fairly intense cleaning process. Virtually all coal cleaned at this level would be used for metallurgical purposes. In addition to being a level that is a substantial fraction of all cleaned coal, this level's resource demands and residuals will bound the upper limit of potential impacts that may arise from coal beneficiation.

A level E plant typically processes about 2.9 million tons of raw or run-of-mine (ROM) coal each year and has an hourly capacity of 950 tons of ROM coal. Therefore, a plant operating 3000 hours per year (representing two 7 1/4 hour shifts per day, 230 days per year, less a ten percent allowance for unscheduled stoppages) has a utilization factor of 34 percent. This falls within a range of utilization factors of 0.3 to about 0.65 cited by the U.S. Department of Energy and the Environmental Protection Agency (1978). The plant has a BTU efficiency of 87.5 percent (Phillips and DeRienzo, 1977). The yield, by weight, assumed for the model system is 70 percent (Phillips and DeRienzo, 1977).

The Department of Energy and the Environmental Protection Agency (1978) also indicated that through proper design and maintenance coal beneficiation plants should last at least twenty years. Specifically, the report states that "Industrial-quality coal cleaning plants. . . [sic] will undoubtedly have a life expectancy of greater than 20 years."

4.2 Coal Beneficiation Constraints

The U.S. Environmental Protection Agency (1977a) has promulgated a New Source Performance Standard (NSPS) (i.e., an emission standard) for coal preparation plants that process more than 200 tons of coal

TABLE 4-1
LEVELS OF COAL PREPARATION

LEVEL & BRIEF DESIG- NATION	SCOPE	YIELD WEIGHT, %	RECOVERY BTU, %	REDUCTION POTENTIAL		WORK DONE ON RAW COAL*	TYPICAL CIRCUITS & EQUIPMENT USED	REFUSE	COMMENTS
				ASH	SULFUR				
A Absence	No Prep.	100	100	None		None-ship ROM coal	None	None	Not general practice
B Breaking	Top size control only	98-100	100	None to minor	None	Crushing to 3 in or less and removal of coarse refuse	Scalping screen, crusher, rotary breaker	Dry lumps and trash	General practice on all ROM coals
C Coarse	Coarse beneficiation	75-85	90-95	Fair to good	None to minor	Level B followed by: Dry screen @ 3/8 in & wet beneficiate @ +3/8 in only. Ship 3/8 x 0 as is.	Same as level B plus vibr. screens, jigs, heavy-media vessels or cyclone, dewatering, thickeners, filters	+3/8 in drained -28M ponded	Used where -3/8 in fraction fairly clean or much rock present in +3/8 in fraction.
D Deliberate	Fine beneficiation	60-80	80-90	Good	Fair	Level B followed by: Wet Screen @ 1/4" & wet beneficiate +28M. Discard 28Mx0.	Same as level C plus concentrating tables or hydrocyclones. Some thermal drying.	+1/4 in drained +28M dewatered -28M ponded or filtered	Used with coals having good washability characteristics.
E Elaborate	Very fine beneficiation	60-80	80-90	Good to excellent	Fair to good	Level D plus wet beneficiate 28 Mx0	Same as level D plus flotation circuits. Thermal drying prevalent.	Same as level D except more fines.	Used with coals having excellent washability characteristics.
F Full	Deep cleaning	60-80	85-95	Clean coal stream: excellent Middling stream: none to fair		Level E after greater than normal size reduction and separation into two streams: clean coal and middlings.	Same as level E plus additional size reduction.	Substantially same as level E.	Two or more washed coal products of different qualities are obtained.

*Coal sizes shown are typical but will vary somewhat with each coal and process selected.

Source: Phillips, P. and P. DeRienzo, 1977. Assessing the Economics of Steam Coal Preparation. In Coal Mining and Processing, Volume 14, Number 7, p. 53. Maclean-Hunter Publishing Corporation, Chicago, Illinois.

per day. For plants containing thermal dryers, it is unlawful to discharge particulate matter in excess of 0.07 grams per dry standard cubic meter of dry gas (g/dscm); for pneumatic coal cleaning equipment, the standard is 0.04 g/dscm. In addition to meeting the NSPS, a coal preparation plant must be suitably sited so that ambient air quality standards will not be exceeded.

Regulations under the Clean Water Act of 1977 require a permit to discharge pollutants into navigable waters. The EPA, acting under the authority of this legislation, has promulgated best practicable control technology (BPT) standards that were implemented in 1977.

Stricter best available technology (BAT) standards are to go into effect by 1983, however, implementation of these standards is behind schedule.

The U.S. Environmental Protection Agency (1977b) has set BPT water pollution standards that specifically apply to coal beneficiation. These standards are detailed in Table 4-2. In addition to the Clean Water Act, the Safe Drinking Water Act (PL 93-523) will restrict operation of affect beneficiation plants that could pollute drinking water sources.

The Federal law that controls the management of solid wastes which could affect coal cleaning plants is the Resource Conservation and Recovery Act (PL 94-580).

The Toxic Substances Control Act (PL 92-523) mandates federal regulation of toxic substances used in the beneficiation process. This may increase the cost of these substances and possibly reduce their availability. Finally, the Noise Control Act (PL 92-574) recommends ambient noise standards which may be adopted by states. This could affect certain components of the beneficiation process.

TABLE 4-2

BPT WATER POLLUTION STANDARDS
PERTAINING TO COAL BENEFICIATION
(Milligrams per Liter)

Limitations for sources whose discharges are normally acidic prior to treatment:

<u>EFFLUENT CHARACTERISTIC</u>	<u>MAXIMUM FOR ANY ONE DAY</u>	<u>EFFLUENT LIMITATIONS AVERAGE OF DAILY VALUES FOR 30 CONSECUTIVE DAYS SHALL NOT EXCEED--</u>
iron, total	7.0	3.5
manganese, total	4.0	2.0
TSS	70.0	35.0
pH	within the range 6.0 to 9.0	

Limitations for sources whose discharges are normally alkaline prior to treatment:

<u>EFFLUENT CHARACTERISTIC</u>	<u>MAXIMUM FOR ANY ONE DAY</u>	<u>EFFLUENT LIMITATIONS AVERAGE OF DAILY VALUES FOR 30 CONSECUTIVE DAYS SHALL NOT EXCEED--</u>
iron, total	7.0	3.5
TSS	70.0	35.0
pH	within the range 6.0 to 9.0	

Note: In general, discharges are acidic in the eastern U.S. and alkaline in the western U.S.

Source: U.S. Environmental Protection Agency, 1977b. Coal Mining Point Source Category Effluent Limitations for Existing Sources, Federal Register.

4.3 Resource Requirements

4.3.1 Auxiliary Energy

Coal preparation plants nationwide on the average consume about 1.6×10^5 kWh of electricity and 4.7×10^8 Btu of oil per 10^{12} Btu of coal input (Hittman, 1974). Assuming a 70 percent weight yield and a Btu efficiency of 87.5 percent, these data imply 2.0×10^5 kWh of electricity and 5.9×10^8 Btu of oil per 10^{12} Btu output for the model plant.

4.3.2 Land

According to University of Oklahoma (1975) data, the fraction of property devoted to a typical coal cleaning plant (irrespective of the level of cleaning involved) consisting of a washing plant, loading area, and the settling pond are 5 percent, 42 percent, and 53 percent, respectively. Hittman (1974) calculated a land use coefficient of 3.5 acres per 10^{12} Btu input for metallurgical coal cleaning plants. Assuming a 70 percent weight yield and a Btu efficiency of 87.5 percent, land use coefficients in terms of 10^{12} Btu output for a metallurgical coal cleaning plant consisting of a washing plant, loading activities and settling pond are 0.2, 1.8, and 2.3 acres, respectively.

4.3.3 Water

At coal preparation plants, particulates are generated during loading and unloading, breaking, conveying, crushing, screening, and storage. Water is needed to control particulates, and to wash the coal to lower the ash and sulfur content. According to the U.S. Environmental Protection Agency (1974) the water loading factor for

mechanically cleaned coal (where most of wet washing is done by the jigging process) is 7.12 acre-feet/100,000 tons input. Assuming a weight yield of 70 percent and a Btu efficiency of 87.5 percent, water consumption for 10^{12} Btu output is 3.7 acre-feet.

4.3.4 Capital

Cost data were obtained from Phillips and DeRienzo (1977). The cost to construct an elaborate beneficiation plant is \$11.91 (1976 dollars) per ton of cleaned coal. Assuming that the heat content of the cleaned coal is 27.5×10^6 Btu per ton, the construction cost is 4.3×10^5 dollars per 10^{12} Btu. Their data on operating cost indicate about 8.8 dollars (1976) per ton of cleaned coal. These data translate into 3.2×10^5 dollars per 10^{12} Btu.

4.3.5 Personnel

Manpower for construction and operation at coal preparation plants were obtained from the U.S. Department of the Interior (1979). Their data suggest that about 15.6 and 2.7 men per 100,000 tons (raw) are required for construction and operation, respectively. Assuming a 70 percent weight yield and a Btu efficiency of 87.5 percent, construction and operating manpower levels in terms of 10^{12} Btu output are 8.1 and 1.5 men, respectively.

4.4 Residuals

Residual coefficients for air pollution, water pollution, and solid waste are shown in Table 4-3.

As the coal is handled, screened, classified, washed and dried, the major source of air pollution is the thermal dryer or pneumatic

TABLE 4-3

EMISSIONS PRODUCED BY COAL BENEFICIATION
(10¹² Btus Produced)

POLLUTANT	GROSS TONS	NET TONS
Air Pollutants ⁽¹⁾		
particulates	91.3	0.9
SO ₂	2.7	0.005
NO _x	1.5	0.6
hydrocarbons	1.1	0.2
CO	5.4	0.2
Water Pollutants ⁽²⁾		
total dissolved solids	142.7	33
total suspended solids	5,868	0.6
aluminum	1.1	0.04
ammonia	0.2	0.05
total ferrous metals	4.6	0.07
dissolved iron	0.2	0.007
suspended iron	4.4	0.06
manganese	0.2	0.03
nickel	0.01	0.003
sulfate	98	18
zinc	0.1	0.005
Solid Waste ⁽³⁾		
primary breaking	0	
coarse cleaning ⁽⁴⁾	2	
raw-coal sizing	0	
primary cleaning	10,157	
froth flotation	5,341	
thermal drying	0	
breaking and sizing	2	
total	15,502	

(1) MITRE Corporation, 1977. Annual Environmental Analysis Report, Volume IV. Prepared for U.S. Energy Research and Development Administration. McLean, Virginia. (The figures presented are weighted national averages based on regional coefficients for 1979.)

(2) These figures include residuals from both refuse piles and the plant itself. They assume the plant is closed cycle and that all refuse is treated.

(3) Hittman Associates, Inc., 1974. Environmental Impacts, Efficiency and Cost of Energy Supply and End Use, Volume I. HIT-593, Columbia, Maryland.

(4) Coarse cleaning includes the removal of tramp iron, mine debris, and some noncombustibles.

coal cleaning equipment. Particulates constitute the major air pollution problem. The range of concentration, quantity, and particle size depends upon the type of collection equipment used to control particulate emissions from the stack. Typical collection efficiencies are: cyclone collectors (product recovery), 70 percent; multiple cyclones (product recovery), 85 percent; water sprays following cyclones, 95 percent; and wet scrubber following cyclones, 99 to 99.9 percent (U.S. Environmental Protection Agency, 1977c).

6

The amount of water pollution is highly dependent on whether the operation is open or closed cycle. The closed cycle results in nearly zero net discharge of water pollution from the plant itself, while the open cycle does not. Both cycles generate water pollution from refuse pile runoff. Since 80 percent of all coal preparation plants are closed cycle, the water pollution coefficients presented in Table 4-3 are for a closed cycle coal cleaning operation (MITRE, 1977).

The solid waste coefficients presented in Table 4-3 were derived from Hittman (1974). Overall, Hittman specifies national average solid waste residuals of 8,110 tons per 10^{12} Btus input for metallurgically cleaned coal. (The value [15,502 tons] in the table represents the solid waste generated per 10^{12} Btus output.)

Noise may affect workers but there should be little or no adverse levels on receptors located outside the plant's boundary.

4.5 References

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5.0 COAL-FIRED POWER PLANT - CONVENTIONAL BOILER

5.1 Characteristics of Conventional Coal-Fired Plant

There is a wide difference among coal-fired steam generators in terms of their designs, particularly with respect to firing method; however, the basic process employed is common to all as the design objective is to produce the required quantity and quality of steam at minimum cost. The following is a brief description of that process.

Air preheated to as much as 315°C (600°F) by the combustion gases is introduced into the combustion chamber with the fuel through multiple burners strategically arranged to promote optimum combustion conditions. In the combustion chamber, the coal (in pulverized form) reacts with the oxygen of the air to release thermal energy at temperatures exceeding 1100°C (2000°F). The walls of the combustion chamber are lined with water-filled tubes which absorb thermal energy and generate steam. The water tubes are filled with liquid or vapor, depending on pressure and temperature conditions. Heat transfer in the combustion chamber cools the combustion gases to about 1100°C (2000°F).

The cooler combustion gases flow from the combustion chamber to the superheat and reheat sections of the steam generator where further heat transfer and gas cooling occur. Steam superheat and reheat are necessary for thermodynamic efficiency and also to prevent steam condensation which would damage the blades of the steam turbines which turn the electric power generators. Modern steam electric power generation systems use steam at pressures ranging from 2000-4000 p.s.i. at a minimum temperature of about 540°C (1000°F). Steam turbines are designed in stages so that steam is sent back to the steam generator for reheat between stages. Most modern systems

are designed with a superheat stage followed by a reheat stage. Some systems are designed with more than one reheat stage. The most efficient fossil fuel-fired-steam-electric system generates one kilowatt of electrical energy from 8,714 Btu of gross thermal energy input. Most modern systems generate one kilowatt hour of electrical energy from about 10,000 Btu heat input (U.S. Environmental Protection Agency, 1978a). Because of the thermal energy losses of the steam turbine thermodynamic cycle and the heat losses from the steam generator, less than 40 percent of the thermal energy of the fuel is converted to electrical energy. About 12 to 20 percent of the gross heat input is lost in the steam generation system and the remainder is lost in the steam turbine system, mostly as latent heat in the turbine condenser.

Combustion gases from the superheat and reheat sections flow to the economizer section where heat is transferred to the steam generator feedwater. Combustion gas temperature out of the economizer ranges from 315°C to 480°C (600-900°F). Combustion gases from the economizer flow to the air preheater. The air preheater heats the air flowing to the steam generator combustion chamber to as much as 315°C (600°F). Combustion gas temperature out of the air preheater ranges from 120°C to 200°C (250-400°F).

To minimize heat loss, large steam generator air preheaters are designed to reduce stack temperature to the lowest level which does not cause corrosion problems. Corrosion will occur in and after the air preheater, if the combustion gas temperature falls below the dew point of sulfuric acid mist. Consequently, air preheaters are designed for higher outlet temperatures when high sulfur fuels are fired than when low sulfur fuels are burned. Heat losses from the steam generation system are also minimized by insulating hot surfaces and by minimizing the quantity of combustion air.

5.2 Constraints

The major constraints limiting the construction and operation of coal-fired steam-electric plants are regulations that are designed to protect the environment. These constraints either limit the selection of the type of coal used for steam generation (for example, one with a low sulfur content) or result in substantial investments to control air and water pollutants and for the disposal of solid wastes.

Emissions of air pollutants are limited by regulations established under the Clean Air Act of 1963, as amended, and these limits vary in terms of several different categories of power plants. Categorization is necessary in terms of the date on which construction of the plant commenced. Plants in existence or on which construction began no later than December 23, 1971, are subject to State Implementation Plans (SIP's) designed to achieve established National Ambient Air Quality Standards. Controls required by SIPs vary from state to state. Plants on which construction commenced after December 23, 1971, are subject to New Source Performance Standards (NSPS). These standards were revised in June 1979 and are applicable to plants for which construction started after September 18, 1978 (44 FR33613).

NSPS are as follows:

	<u>OLD STANDARDS</u>	<u>REVISED STANDARDS</u>
	<u>Pounds Emitted Per</u>	<u>10⁶ Btu Input</u>
Particulate matter	0.10	0.03**
Sulfur dioxide	1.20	0.60 - 1.20**
Nitrogen oxides	0.70*	0.60***

*Except lignite - no limit.

**Also requires a percentage reduction in potential emissions as follows: particulate matter - 99%; sulfur dioxide - 70% (at 0.6 lb rate) to 90% (at 1.2 lb rate); nitrogen oxides - 65%.

***Except subbituminous coal - 0.5 lb per 10⁶ Btu input.

Water pollutant discharges from coal-fired power plants are limited under the Clean Water Act. Under this legislation, effluent limitations must be met by the application of the Best Practicable Technology Currently Available (BPTCA) by July 2, 1977, and of the Best Available Technology Economically Achievable (BATEA), by July 1, 1983. Effluent limitations under both BPTCA and BATEA have been established by effluent source for pH, total suspended solids, oil and grease, and, for some sources, for certain dissolved solids.

5.3 Resource Requirements

A 500 MWe unit power plant was selected for the purpose of developing both resource requirements and residuals data. Assuming a 55 percent load factor (the national average), a plant of this size will produce 2.4×10^9 kWh annually or the equivalent of 8.2×10^{12} Btu energy output.

Resource requirements, normalized to a base of 10^{12} Btu output, have been varied by assuming the use of a representative eastern coal and a representative western coal. These coal types are:

- A North Central Appalachian coal with a heat content of 11,500 Btu per pound, 2.3 percent sulfur content, and 9.2 percent ash content.
- A Western Rocky Mountain Province coal with a heat content of 10,000 Btu per pound, 0.6 percent sulfur content and 7.7 percent ash content.

Assuming a thermal efficiency of 34.13 percent, fuel requirements per 10^{12} Btu of energy output are, therefore, 127,390 tons of the Eastern coal or 146,500 tons of the Western coal. A steam-electric power plant requires land committed to the plant itself,

for both coal storage and waste disposal, and as a buffer zone. Land committed to these uses varies considerably from plant to plant and cannot be linearly related to the size of the plant. According to one study (U.S. Fish and Wildlife Service, 1978), land requirements can vary from 81 acres for a 100 MWe plant to 800 acres for a 2100 MWe plant. Based on the data provided by this study, land requirements for a representative coal-fired power plant operation under the "old" New Source Performance Standards have been estimated as follows:

	EASTERN COAL	WESTERN COAL
	Acres per 10^{12} Btu	
Plant site, permanent use	32.2	32.6
Waste disposal, temporary use	12.8	5.9

A consumptive use of water is required primarily to offset evaporative and drift losses from the plant's cooling towers. On a per 10^{12} Btu output basis, such use averages 134 acre-feet for the eastern (North Central Appalachian) coal and 154.5 acre-feet for the western (Western Rocky Mountain Province) coal (U.S. Department of the Interior, 1979).

5.4 Residuals

5.4.1 Air Pollutants

Emissions of air pollutants from coal-fired steam-electric plants are a function of both the characteristics of the coal combusted and in the case of three of the criteria pollutants -- particulates, sulfur oxides, and nitrogen oxides -- of the emission rates permitted under EPA regulations.

Emissions per 10^{12} Btu of energy output for the above three criteria pollutants have been calculated as if the plant were subject to the "old" New Source Performance Standards (NSPS), and to the "revised" NSPS. Emissions of all pollutants of interest have been calculated on a gross (uncontrolled) basis. For all criteria pollutants of interest, including hydrocarbons and carbon monoxide, these data were developed from EPA emission factors (Office of Air Quality Planning and Standards, 1975). Trace element emissions were calculated using the Trace Element Emission Model (TEEM) developed by International Research and Technology Corporation. Calculations of these latter emissions data required an estimate of how much of the trace elements are removed by particulate control devices (ESP, mechanical precipitators, baghouses), as well as the trace element concentration in the representative coal types. The air emission data developed are presented in Table 5-1.

5.4.2 Water Pollutant Discharges

Water pollutant discharges per 10^{12} Btu of energy output are taken directly from the Annual Environmental Analysis Report (MITRE Corporation, 1977) and are presented in Table 5-2.

5.4.3 Solid Waste Generation

The secondary residuals, which result in solid waste, come from four waste streams: fly ash, bottom ash, scrubber waste, and sludge from water treatment. The composition and amount of the first three streams can be easily quantified. However, data on the solid waste resulting from the water treatment process are not available for the representative design evaluated. The waste from water treatment processes is expected to be much smaller than the wastes from the other three streams although potentially it may be more toxic. Thus, only

TABLE 5-1

AIR POLLUTION FROM COAL-FIRED UTILITIES
(Tons Emitted Per 10^{12} Btu Output)

AIR POLLUTANT	EASTERN COAL (North Central Appalachian)			WESTERN COAL (Western Rocky Mountain Province)		
	Gross	Plant Under NSPS	Plant Under Revised NSPS	Gross	Plant Under NSPS	Plant Under Revised NSPS
		Net	Net		Net	Net
Particulates	9,376.0	147.0	44.0	9,024.0	147.0	44.0
SO ₂	5,567.0	1,758.0	725.0	1,670.0	1670.0	501.0
NO _x	1,147.0	1,025.0	401.0	1,318.0	1,025.0	461.0
Hydrocarbons	19.0	19.0	19.0	22.0	22.0	22.0
CO	64.0	64.0	64.0	73.0	73.0	73.0
Arsenic	1.4	1.4	1.4	0.14	0.007	0.007
Beryllium	0.20	0.14	0.14	0.06	0.001	0.001
Cadmium	0.03	0.0014	0.0014	0.04	0.001	0.001
Fluorine	7.0	0.54	0.54	7.3	0.56	0.56
Lead	1.2	0.10	0.10	0.58	0.05	0.05
Mercury	0.16	0.16	0.16	0.005	0.005	0.005
Selenium	0.44	0.14	0.14	0.14	0.04	0.04
Manganese	20.5	1.2	1.2	2.5	0.14	0.14

TABLE 5-2

WATER POLLUTION FROM COAL-FIRED UTILITIES
(Per 10¹² Btus Electricity Produced)

WATER POLLUTANTS	TONS
BOD	1.41
COD	137.18
total suspended solids	0.33
total dissolved solids	873.53
aluminum	0.30
chromium	0.01
nonferrous metals	110.79
zinc	0.05
sulfates	41.10
nickel	3.62
nutrients	
nitrates	1.82
ammonia	0.06
phosphorus	0.17
surfactants	0.39

Source: MITRE Corporation, 1977. Annual Environmental Analysis Report, (AEAR). Draft, Volume IV. McLean, Virginia.

solid waste from fly ash removal, bottom ash, and scrubber wastes is discussed in this section.

The quantity of ash (both bottom ash and fly ash) and scrubber waste is dependent of the type of coal used and the type of pollution control technology used.

The bottom ash is calculated as some fraction of the total ash content of the coal. For dry pulverized coal, this is 15 percent of the coal. The uncontrolled emissions of fly ash represent the balance; therefore, the quantity of fly ash for disposal as solid waste is the difference between uncontrolled emissions and the quantity that can be emitted under the EPA regulations applicable to a given plant.

For the development of the quantity of scrubber waste produced, it was assumed that a limestone-lime scrubber was used to control sulfur oxides. The quantity of waste produced is a function of the sulfur content of the coal, the proportion of sulfur that adheres to bottom ash, the permissible sulfur oxides emission rates, and the quantity of unused sorbent as well as the specific reactions that take place to convert sulfur dioxide to a solid (calcium sulfates).

The ratio between scrubber waste and sulfur dioxide captured varies in the range between 2.15 and 2.70 depending on operating conditions. Such a ratio can be used to compute the solid waste generated when actual data are not available. The value recommended by EPA (U.S. Environmental Protection Agency, 1976) is 2.15. This value is supported by a study (U.S. Environmental Protection Agency, 1978b) of scrubber waste disposal alternatives; the value of the ratio calculated from data in this study is 2.18.

Quantities of solid wastes generated, normalized to a per 10¹² Btu of output energy basis, are presented in Table 5-3.

5.5 Economic Data

5.5.1 Air Pollution Abatement Costs

There are numerous control strategies which can control the principal air pollutants: particulates, sulfur oxides, and nitrogen oxides. This section deals only with the most common technologies: electrostatic precipitators, flue gas desulfurization (both regenerative and nonregenerative), and nitrogen oxide control from boiler modifications.

The costs associated with constructing and operating electrostatic precipitators were taken primarily from EPA sources. To select costs, it is necessary to specify the operating conditions for a typical electric utility as specified below:

- Cold side ESP
- Control efficiency 99 percent
- Eastern coals: high sulfur and low sodium oxide
- Western coals: low sulfur and high sodium oxide
- Pulverized coal

The utility boilers in the East are assumed to burn high sulfur coal and those in the West burn low sulfur coal. The eastern coal is bituminous and the western coal is subbituminous. The eastern utility is assumed to consume high sulfur coal in a 500 MW pulverized coal

TABLE 5-3

SOLID WASTE FROM COAL-FIRED UTILITIES
(Tons per 10^{12} Btu Output Energy)

WASTE STREAM	EASTERN COAL (North Central Appalachian)		WESTERN COAL (Western Rocky Mountain)	
	Without Scrubber	With Lime Scrubber	Without Scrubber	With Lime Scrubber
Bottom Ash	2201.4	2201.4	2441.1	2441.1
Fly Ash	8676.4	8676.4	8735.2	8735.2
Scrubber Sludge	-0-	15247.0	-0-	2511.0

Source: U.S. Environmental Protection Agency, 1976. Simplified Procedures
for Estimating Flue Gas Desulfurization Costs.
EPA-600/2-76-150. Research Triangle Park, N.C.

boiler, yielding capital costs of \$8 per kW and an operating cost of 0.21 mills per kWh. The western utility consumes a low sulfur subbituminous coal in a 500 MW pulverized boiler, yielding capital costs of \$18 per kW and operating costs of 0.36 mills per kWh.

The efficiency (E) of an electrostatic precipitator is a function of the ratio of the collector area (A) to the volumetric flow (V) and a parameter known as the precipitator rate (W).

$$E = 1 - \frac{A}{V} W$$

The precipitator rate (W) decreases as the resistivity of the coal increases. Recent studies indicate that the resistivity of western coals is higher than that of high sulfur eastern coals. As the precipitator rate (W) decreases, the area must increase to maintain the same removal efficiencies. The costs are proportional to the area of the precipitator; thus, as the resistivity of the coal decreases, the costs increase. This explains the difference in cost between eastern and western coals.

A Teknekron Corporation study provides higher costs: \$16 per kW for eastern coals and \$57 per kW for western coals. An EPA (1977) report was used because it is relatively recent and was derived from a sample of actual costs. The values are shown in Table 5-4.

As of the end of 1977, there were approximately 30 operational FGD systems on utility boilers, with 111 systems under construction or planned. Most of these are committed to the lime/limestone wet scrubber. For the purpose of this discussion, it is assumed that all scrubbers are lime/limestone wet scrubbers. Numerous cost estimates for scrubbers have been presented. Four FGD estimates are presented

TABLE 5-4
COST OF PRECIPITATORS

	CAPITAL		OPERATION AND MAINTENANCE	
	Dollars Per kW	Dollars Per 10 ¹² Btus Electricity	Mills Per kW	Dollars Per 10 ¹² Btus Electricity
Electric Utilities- Coal-New-West	18.0	926,000	0.36	97,000
Electric Utilities- Coal-New-East	8.0	412,000	0.21	56,000

Note: All costs are in 1975 dollars.

Source: U.S. Environmental Protection Agency, 1977. Operation and Maintenance of Particulate Control Devices on Coal-Fired Utility Boilers. (EPA 600/277-129). Research Triangle Park, North Carolina.

in Table 5-5. The EPA cost estimates are used because they reflect the assumptions which are compatible with the likely NSPS for utilities. They are somewhat higher than the other cost estimates. This can probably be attributed to two factors:

- These cost estimates are very recent and scrubber cost estimates have been going up over time.
- These cost estimates assume that by-passing the scrubber will be permitted; thus, a single back up scrubber is assumed.

The NSPS for NO_x emissions from conventional boilers cannot be met without some boiler modifications (for coal burning). Three boiler modification techniques are discussed below.

- Low excess air firing - This consists of reducing the air-to-fuel ratio in the combustion zone so that lower than design excess air is available for combustion. This lowers the temperature of the combustion zone and NO_x emissions are reduced from 30 to 50 percent. This method has not been applied very often since increased fly ash and CO emissions result from using this control device.
- Staged combustion - Air below the stoichiometric minimum is sent to the combustion zone and partial combustion occurs. Additional air is sent to the secondary zone where combustion is completed. Staged combustion results in reduction of 20 to 60 percent of the NO_x emissions and is the most widely used control technique.
- Flue gas recirculation (FGR) - In this method, the combustion gases are diluted with the flue gases, thus lowering the temperature of the combustion gases and resulting in lower NO_x emissions. FGR is not expected to be widely used because of the resulting design problems for new boilers.

For cost purposes, the staged combustion method will be considered. It is also assumed that emissions for new facilities will be identical to NSPS.

TABLE 5-5

COST OF FLUE GAS DESULFURIZATION

CAPITAL COST Dollars per kW (in 1975 dollars)				
	TBS	Teknekron	EPA	MPPM
500 MW _e	NA	\$79	\$96.6	\$59.7
1,000 MW _e	\$55	\$58	NA	\$56.3

OPERATION AND MAINTENANCE COST Mills per kW (in 1975 dollars)				
	TBS	Teknekron	EPA	MPPM
500 MW _e	NA	2.2	3.0	NA
1,000 MW _e	NA	1.7	NA	NA

Assumes 4 percent sulfur coal, 90 percent efficiency

NA - Not Available

Sources: Teknekron, Inc. (undated). An Integrated Technology Assessment of Electric Utilities.

Roig, R. et al., 1977. Materials-Process-Product Analysis of Coal Process Technology - Final Report for Project Phase II, Volume I-III. Department of Energy, Washington, D.C.

Temple, Barker, and Sloan, 1976. Economic and Financial Impacts of Federal Air and Water Pollution Controls on the Electric Utilities Industry for EPA.

- The Teknekron study compiled cost estimates for NO_x controls and found a wide variation. For new plants, the capital costs ran from \$1 to \$4 per kW, and for retrofit facilities, the costs were \$1 to \$9 per kW. The costs associated with the retrofitting of a West Coast utility using the staged-combustion technique were studied in detail. These costs were found to be closer to the upper range given above (\$9 for retrofit per kW and \$4 for new plants per kW). The upper range was used for this study.

5.5.2 Water Pollutant Controls

The estimated cost of building a chemical waste treatment plant for a 500 MW_e steam electric power plant is \$444,400. For a 500 MW power plant with a capacity factor of 0.55, the construction cost is equivalent to \$54,200 per 10¹² Btus annual output.

The annual operating and maintenance costs of a chemical waste treatment plant for a 500 MW_e steam power plant are estimated at \$125,500 by EPA or \$15,300 per 10¹² Btus of electricity. EPA estimated the cost of labor for water pollution abatement at a 500 MW plant to be \$105,000 per year. Using EPA's assumption of \$15,000 annual salary per worker, it follows that seven personnel are required annually at a 500 MW_e plant. This is equivalent to 0.85 man years per 10¹² Btus electricity.

5.6 References

- MITRE Corporation, 1977. Annual Environmental Analysis Report, (AEAR), Draft, Volume IV, McLean, Virginia.
- Office of Air Quality Planning and Standards, 1975. Compilation of Air Pollution Emission Factors, Second Edition. EPA AP-42. U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.
- Roig, R. et al., 1977. Materials-Process-Product Analysis of Coal Process Technology - Final Report for Project Phase II, Volume I-III. Department of Energy, Washington, D.C.

Teknekron, Inc., (undated). An Integrated Technology Assessment of Electric Utilities.

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U.S. Environmental Protection Agency, 1978a. Economics of Disposal of Lime/Limestone Scrubbing Wastes: Untreated and Chemically Treated Wastes. EPA-600/7-78-023a. Research Triangle Park, North Carolina.

U.S. Environmental Protection Agency, 1978b. Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standards, EPA-450/2-78-006a. Research Triangle Park, North Carolina.

U.S. Fish and Wildlife Service, 1978. Impacts of Coal-Fired Power Plants on Fish, Wildlife and Their Habitats. U.S. Department of the Interior, Washington, D.C.

6.0 FLUIDIZED-BED COMBUSTION

6.1 Characteristics

Fluidized-bed combustion (FBC) is one method of burning coal to produce steam for process heat for industrial and commercial uses, and for electric power generation. Solid coal and sorbent particles are suspended in a continuous upward flow of air during combustion, causing the particles to act in a fluid state, hence the term fluidized bed.

Coal and a sorbent (limestone or dolomite) are fed into the main fluidized-bed where combustion takes place (see Figure 6-1). The heat produced from combustion is transferred to water in pipes running through the bed, converting it to steam. The sorbent is used to remove the sulfur dioxide (SO_2) generated during combustion thus eliminating the need for a downstream flue gas desulfurization system to control SO_2 emissions. A substantial majority (about 90 percent) of the particulates entrained in the flue gas can be removed by means of a cyclone; further removal can be achieved by a baghouse or electrostatic precipitator (ESP). The recovered material can be recycled to a carbon burn-up cell (CBC) to increase the efficiency of the FBC process. Other environmental controls are achieved by the chemistry of the bed. NO_x emissions are lower than those from conventional coal combustors due to the relatively low temperature of the fluidized-bed. SO_2 emissions are reduced substantially by the addition of the sorbent material to the fluidized bed enabling the FBC to meet relatively strict SO_2 standards without flue gas desulfurization.

6-2

SOURCES: Bradly, W.J. et al., 1978. Conceptual Design of an Atmospheric Fluidized Bed Electric Power Generating Plant, U.S. Department of Energy, Washington, D.C.

Fluidized Combustion Company, 1978. Preliminary Design and Cost Estimate for An Atmospheric Fluidized-Bed Steam Generator, TVA.

FIGURE 6-1
FUNCTIONAL FLOW SHEET FOR FLUIDIZED BED COAL COMBUSTION

The self-contained, clean-burning aspect of fluidized-bed combustion appears attractive, especially for small boilers where the use of limestone scrubbers may not be practical. It is considered to be appropriate for small applications such as commercial space heating (Cart et al., 1977).

6.2 Constraints

The fluidized-bed system of coal combustion has fewer operational constraints than does the conventional coal-fired boiler. The system can be applied to a wide range of boiler sizes and types of coal. The current interest in FBC is motivated in large measure by regulations that limit the amount of SO_2 emitted with the flue gas. The compatibility of this technology with environmental constraints is demonstrated by the installation of a coal-fired fluidized-bed heating plant (100,000 pounds per hour saturated steam) at Georgetown University. This unit is located in an area of Washington D.C. which has strict zoning regulations (Arthur G. McKee Company, 1978).

The future use of fluidized-bed combustion could be seriously limited if the amount of sulfur that has to be removed is much greater than 80 to 90 percent because of the higher costs associated with the larger amounts of sorbent required (Chemical Week, 1978).

Another limitation of this technology is the disposal of its solid waste, namely, ash and spent sorbent (Table 6-1). (The data shown apply to a stream prior to CBC.)

TABLE 6-1
COMPOSITION OF THE SOLID WASTE
FROM FLUIDIZED-BED COMBUSTION

<u>COMPONENT</u>	<u>PERCENT</u>
Calcium sulfate	42
Ash	31
Unreacted lime	24
Carbon	3

Disposal of such material could be expensive (lined landfill) for large fluidized-bed unit operations.

6.3 Resource Requirements

For the purpose of describing resource consumption for and environmental residuals produced by FBC units, two atmospheric fluidized bed combustion plants, on an electric utility scale operation, have been modeled. The efficiencies of these units are comparable to those of conventional coal-fired units. While FBC units can accept any type of coal as input material, one model (814 net MW_e) utilizes bituminous coal at an efficiency of 35.8 percent whereas, another unit (536 net MW_e) uses sub-bituminous coal at an efficiency of 34.4 percent. These models represent specific engineering designs developed for plants of these capacities for the U.S. Department of Energy (Bradley et al., 1978) and the U.S. Environmental Protection Agency (Reese, 1977). Operating parameter values for these models, and for other examples of FBC units, are presented in Table 6-2.

As shown in the table, the primary inputs are coal and a sorbent (limestone or dolomite). The amount of sorbent required is a function of the amount of sulfur to be removed; in general, a calcium (a component of limestone) to sulfur mole ratio of 2:1 or greater is required to meet current SO₂ emission standards (Reese, 1977).

TABLE 6-2

CHARACTERISTICS OF VARIOUS FLUIDIZED-BED COAL COMBUSTION SYSTEMS

Type of Boiler	AFB ⁽¹⁾	PFB ⁽¹⁾	AFB ⁽²⁾	AFB ⁽³⁾	AFB ⁽³⁾	AFB ⁽⁴⁾	AFB ⁽⁵⁾
Output	814 MW _e net	904 MW _e net	150 MW _e net	108 Btus/hr	108 Btus/hr	536 MW _e net	800 MW _e net
Air Pollutants (lbs per hr)							
SO ₂	7,977	5,424	1,736	154.0	100.0	6,449	9,312
NO _x	2,100	1,175	465	62.5	62.5	2,388	
CO	309	180	59				
Particulates	765	814	145	12.5	12.5	597	
Solid Waste (lbs per hour)	237,688	309,530	63,500	4,583	2,500	103,142	
Water Flow (lbs per hr)	4,128,038	4,111,753	TBS	TBS	TBS	TBS	5,844.212
Coal (lbs per hr)	719,495	730,070	133,600	12,000	13,000	741,500	644,912
Coal Type	Illinois #6	Illinois #6	Bituminous (10,940 Btus/lb)	Illinois #6	San Juan Subbitu.	Wyoming Subbitu.	TBS (9000 Btus/lb)
Sorbent (lbs per hr)	184,941	335,836	57,500	4,500	TBS	52,700	226,304
Efficiency (percent)	35.8 Electric	39.2 Electric	86.2 Stream	TBS	TBS	TBS	TBS

Notes: AFB = Atmospheric Pressure Fluidized Bed; PFB = Pressurized Fluidized Bed.
 Superscripts on AFB and PFB refer to references cited on the following page.
 TBS = To be supplied.

SOURCES OF TABLE 6-2

- (1) Bradley, W.J., et al., 1978. Conceptual Design of an Atmospheric Fluidized-Bed (AFBC) Electric Power Generating Plant Interim Report. United States Department of Energy, Washington, D.C.
- (2) Farmer, M.H., et al., 1977. Applications of Fluidized-Bed Technology to Industrial Boilers. (EPA-600/7-77-011), Research Triangle Park, North Carolina.
- (3) Fluidized Combustion Company, 1978. Preliminary Design and Cost Estimate for an Atmospheric Fluidized Bed Steam Generator, Knoxville, Tennessee.
- (4) Hansen, W.A., et al., 1978. Conceptual Studies and Preliminary Design of a Fluid Bed Fired Boiler for Service in an Electric Utility. Tennessee Valley Authority. Knoxville, Tennessee.
- (5) Reese, J.T., (TVA), 1977. Utility Boiler Design/Cost Comparison Fluidized-Bed Combustion vs. Flue Gas Desulfurization, (EPA-600/7-77-126), Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina.

Feedwater (boiler makeup) is another input to the fluidized-bed plant. The amount of feedwater required is expected to be equal to that of a conventional coal-fired electric power station.

Land for a fluidized-bed power station is required for plant and waste disposal facilities. The amount of land for the plant proper is approximately equal to that of a conventional coal-fired electric power station; as noted previously, land requirements for waste disposal could be greater than for the conventional plant.

6.4 Residuals

The primary justification for fluidized-bed technology is its ability to reduce the emissions of SO_2 and NO_x from coal combustion. The SO_2 emissions are reduced by the chemical action of the sorbent material. This reduction is comparable in efficiency to the control efficiencies achieved by conventional limestone scrubbers. The application studied here emphasizes large electric utility scale uses of FBC. Emissions associated with a variety of such uses including general industrial applications are shown in Table 6-2. Most of the applications are fluidized-beds operating at atmospheric pressure (AFB) since this is the fluidized-bed technology that is the nearest to commercial use. Pressurized fluidized-beds (PFB) operating at pressures higher than atmospheric are less well developed. Engineering studies of atmospheric fluidized-beds using bituminous coal and western subbituminous coal (Table 6-3) have been selected as being representative for the purpose of normalizing residuals to a per trillion Btu base in this discussion. For each coal type, all of the relevant values were taken from a single engineering study to obtain the benefits of a coherent engineering analysis and to avoid errors arising from the combining of data contained in individual reports that use different coals.

TABLE 6-3

MATERIAL REQUIREMENTS AND
EMISSIONS FOR COAL-FIRED
ATMOSPHERIC FLUIDIZED-BED
(Tons per 10^{12} Btus Produced)

	REFERENCE	
	(1)	(2)
<u>Pollutants</u>		
Air Pollutants		
SO _x	1,400	1,600
NO _x	378	583
CO	56	
HC	15	
particulates	138	145
Solid Waste	42,778	25,000
<u>Input Materials</u>		
Coal	Bituminous	Subbituminous
	129,000	181,000
Sorbent	33,000	12,829

Note: The hydrocarbon emission value is from Fluidized Combustion Company, 1978. Preliminary Design and Cost Estimate for an Atmospheric Fluidized-Bed Stream Generator, Tennessee Valley Authority, Knoxville, Tennessee.

Sources: (1) Reese, J.T. (TVA), 1977. Utility Boiler Design/Cost Comparison Fluidized-Bed Combustion Vs. Flue Gas Desulfurization, (EPA-600/7-77-126), EPA Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina.

(2) Bradley, W.J. et al., 1978. Conceptual Design of an Atmospheric Fluidized-Bed (AFBC) Electric Power Generating Plant Interim Report; United States Department of Energy, Washington, D.C.

The plant burning low sulfur coal requires less sorbent input and therefore generates less solid waste than the high sulfur plant. If the SO_2 standard were stated in terms of percentage of sulfur removal, the low sulfur plant would use more sorbent and generate more solid waste than it does in this example.

NO_x emissions from fluidized-bed combustion are quite low due to the lower operating temperature of the fluidized-bed system. Likewise, trace element emissions are expected to be lower than with conventional coal combustion because the low bed temperature will volatilize fewer trace elements (Hansen et al., 1978). Water pollutants emitted by fluidized-bed combustion are approximately the same as those emitted by a conventional electric power station.

Questions have arisen about the landfill disposal of solid waste from the fluidized-bed boiler. It has been suggested that the lime (CaO) in the waste material will react in an exothermic reaction with water and that lined lagoons or a lined landfill would be required to dispose of the water because of the high pH of the leachate (Hansen et al., 1978). If such steps are required, the cost of the process could increase. A favorable aspect of the fluidized-bed is that its solid wastes are dry, making them more manageable than the wet wastes from a SO_2 scrubber.

6.5 Economic Data

Construction cost is estimated to equal \$32.7 million per 10^{12} Btus annual output for a bituminous coal-fired system and \$18.3 million per 10^{12} Btus annual output for a comparable subbituminous coal-fired system (Reese, 1977; Bradley et al., 1978). These estimates are for plants with operating characteristics described in Section 6.1 above.

6.6 References

- Arthur G. McKee Company, 1978. 100,000 Pound Per Hour Boiler Cost Study Comparing: A Fluidized-Bed Combustion Boiler Burning Non-Compliance Coal - A Conventional Spreader Stoker Fired Boiler Burning Non-Compliance Coal and A Conventional Spreader Stoker Fired Boiler Burning Compliance Coal, U.S. Department of Energy, Washington, D.C.
- Bradley, W.J., et al., 1978. Conceptual Design of an Atmospheric Fluidized-Bed (AFBC) Electric Power Generating Plant Interim Report. United States Department of Energy, Washington, D.C.
- Carr, R.C. (KVB Inc.), 1976. Effectiveness of Gas Recirculation and Staged Combustion in Reducing NO_x on a 560-MW Coal-Fired Boiler, Electric Power Research Institute, Palo Alto, California.
- Cart, E.N., Jr., et al., 1977. Evaluation of the Feasibility for Widespread Introduction of Coal Into the Residential and Commercial Sectors - Volume II - Technical Section, Council on Environmental Quality, Washington, D.C.
- Chemical Week, 1978. Volume 122, No. 8.
- Farmer, M.H. et al., 1977. Applications of Fluidized-Bed Technology to Industrial Boilers. (EPA-600/7-77-011), Research Triangle Park, North Carolina.
- Fluidized Combustion Company, 1978. Preliminary Design and Cost Estimate for an Atmospheric Fluidized-Bed Steam Generator, Knoxville, Tennessee.
- Hansen, W.A., et al., 1978. Conceptual Studies and Preliminary Design of a Fluid Bed Fired Boiler for Service in an Electric Utility, Tennessee Valley Authority, Knoxville, Tennessee.
- Reese, J.T., (TVA), 1977. Utility Boiler Design/Cost Comparison Fluidized-Bed Combustion Vs. Flue Gas Desulfurization, (EPA-600/7-77-126), EPA Industrial Environmental Research Laboratory, Research Triangle Park, North Carolina.

7.0 MAGNETOHYDRODYNAMIC ELECTRIC POWER GENERATION

7.1 Characteristics of Magnetohydrodynamics

The magnetohydrodynamic (MHD) generating system is an alternative method of generating electric power. Conventional fossil power plants use rotating machinery to transform the gas expansion resulting from fuel combustion into mechanical energy which is directly converted into electrical energy. Material problems of the rotating or reciprocating components limit the maximum temperature and, hence, the Carnot efficiency of the cycle.

In the MHD cycle, there are no moving parts exposed to high temperatures. This allows for potentially higher maximal temperatures and, hence, for potentially higher efficiency (possibly 50 percent). Electricity in a conventional generator is "produced" by moving a conductor through a magnetic field. In the case of MHD, the conductors are ionized combustion gases, which attain their movement by expanding through a nozzle. Perpendicular to the gas flow exists a strong magnetic field which is established by a superconducting magnet. The ionized flue gases complete an electrical circuit between electrodes on either side of the MHD duct. At the design maximal temperature of about 5000°F, the ionization of the flue gases alone is insufficient to provide the required electric conductivity. Therefore, potassium or cesium compounds with much lower ionization potential are added (seed). The overall degree of ionization of the hot flue gas/seed mixture is sufficient at 5000°F, but falls off sharply at lower temperatures. Therefore, cooler layers of flue gas/seed close to the combustor walls do not contribute to the electric conductivity. To minimize this effect, the combustor and channel walls are kept at about 3000°F. First generation MHD generators are open cycle plants, i.e. the hot gas stream is not recycled except for the seed material.

A combustion temperature of 5000°F can only be reached by burning coal with oxygen or highly preheated air. Generally, slightly fuel rich condition are used. There are designs of either one or two stage combustors with or without ash removal as molten slag. Carry over slag causes problems with respect to the electrical isolation.

Figure 7-1 shows a simplified flow diagram of the functional steps of an MHD power plant. The combustor is supplied with pulverized coal and preheated compressed air. Some designs call for preheating up to 3000°F which is beyond the present proven capabilities. In addition, the coal has to be dried to 2 to 5 percent moisture level. The lower limit is difficult to achieve. Any remaining water has adverse effects; it lowers the peak temperature (heat of vaporization) and it captures alkali metals making them unavailable for ionization. The subsequent channel works as an expansion nozzle to increase the gas flow velocity. As a result of the energy extraction in the channel (i.e. the electric power generated in the channel), the channel exit temperature is about 3600°F.

The high temperature MHD topping cycle is followed by a more conventional steam bottom cycle.

More energy is extracted from the hot flue gas/seed mixture in the radiant boilers. The temperature decrease from 3600 to 3000°F must be done in a time controlled manner (NO_x control). Air addition downstream of the radiant boiler brings the fuel/air ratio to slightly fuel lean for maximal combustion efficiency (also CO control). A more conventional system of air preheaters, steam superheaters and economizers with the necessary steam turbines forms the rest of the steam bottom cycle.

Sources: Hoover, D.Q. et al., 1966. Feasibility Study of Coal Burning MHD Generation, Volume I. Department of the Interior - Office of the Coal Research, Washington, D.C.

Corman, J.C. et al., 1976. Energy Conversion Alternatives Study - ECAS - General Electric Phase I Final Report, Volume II, Part 3 NAS-ERDA-NSF, Washington, D.C.

FIGURE 7-1
FUNCTIONAL FLOW SHEET FOR MAGNETOHYDRODYNAMIC
ELECTRIC POWER PLANT

Depending on the amount of slag (ash) rejected in the combustor, there are numerous solid material removal methods like electrostatic precipitators, cyclones, or baghouses. Furthermore, there is condensation of seed and other matter in the radiant boiler, superheaters or air heat exchangers. The alkali seed is recycled.

7.2 Constraints

Constraints on the future use of MHD are primarily technical. The design and operation of a commercial MHD facility are difficult due to the severe operating conditions, mostly due to the high operating temperature in the combustor and in the MHD generator's channel (see Table 7-1). Since the wall temperature in the combustor and the channel have to be very high for efficiency reasons, erosion/corrosion of these components are key problem areas. The severity of these problems are increased by the high dust loading. Some of the molten slag is supposed to form a protective layer at the wall. The slag, however, causes difficulties to electrically isolate the combustor from the channel or from the coal feed/ash removal system. It is not convenient to isolate the coal preparation/feeding components due to explosion hazards in a case of isolation break-down (the potential commonly reaches 20,000 V).

As described before, the preheaters (heat exchangers) required for MHD generators are beyond proven technology. Some designs circumvent extreme heat exchanges by essentially producing medium Btu gas in a fluidized-bed. However, medium Btu gas production without the use of oxygen is also an unproven technology.

Further difficulties are caused by arcing in the channel. While the super conducting magnets are known technically, there are scale-up problems. If the magnetic field, for example, collapses, the hot

TABLE 7-1

OPERATING CONDITIONS WITHIN AN OPEN CYCLE
COAL-FIRED MHD GENERATOR

CHARACTERISTIC	REPORTED RANGE OF VALUES
combustion gas temperature	3700-5000° F
combustion gas pressure	1-16 atmospheres
combustion gas velocity	570-780 meters/second
MHD generator gas channel length	6-18 meters for MHD generator power output of 300 to 400 MW

Source: Mannal, C. and N.W. Mather, 1969. Magnetohydrodynamics, Standard Handbook for Electrical Engineers, New York.

flue gas does not cool sufficiently in the channel, probably causing burnouts in the steam cycle.

7.3 Resource Requirements

Resource requirements for an open cycle MHD system are based on a conceptual design developed for the Energy Conversion Alternatives Study (ECAS) sponsored jointly by the Energy Research and Development Administration, the National Aeronautics and Space Administration, and the National Science Foundation. The unit modeled is a 1,933 MWe (gross output) system using Illinois No. 6 coal (higher heat value - 10,788 Btu per pound). Based on a plant efficiency of 49.8 percent, 95,890 tons of coal will be required per trillion Btu of energy output (2.93×10^8 kWh of electrical energy). Coal required is substantially less than the quantity required for a conventional power plant of the same scale due to the higher plant efficiency.

Documentation of the conceptual design (Corman et al., 1976) indicates that other major resource requirements include land (committed to use for the plant site and for the disposal of solid wastes) and water consumed in the form of evaporative loss. Normalized to a per trillion Btu output base, these resource requirements are estimated to be 47.3 acres and 306 acre-feet, respectively.

7.4 Residuals

The most significant potential environmental problem is the production of high levels of nitrogen oxides. The extreme temperatures in the MHD combustor and channel cause the NO production to reach near equilibrium levels--a few thousand parts per million (ppm). High nitrogen content of the coal is irrelevant to the peak NO level. The main NO reduction is hopefully achieved in the radiant boiler.

The lower temperature and slightly fuel rich condition in the boilers result in much lower NO equilibrium levels. Unfortunately, the NO destruction reaction "freezes" below a certain temperature. This makes the temperature-time control in the radiant boiler crucial for NO reduction. Conventional combustion devices rely more on reduced NO formation rates than on optimized NO reduction rates. If the required NO_x standards cannot be reached in the radiant boilers, catalytic reduction or ammonia addition (forming N₂ with NO_x) is envisioned. Neither one is proven technology in the U.S. for coal-fired furnaces. Sulfur removal is planned by conventional scrubbers and/or alkali sulfate removal. The alkali has to be regenerated and recycled as seed material. By comparison to the NO_x problem, the sulfur problem for MHD is "conventional."

Particulates emissions in an MHD cycle can be controlled at lower temperatures by conventional means such as baghouses. Particulates cause less of an environmental problem for MHD than a material problem.

The emission coefficients were obtained from the interagency report, Energy Conversion Alternatives Study (ECAS) (Corman et al., 1976). These values are listed below:

SO _x	0.4×10^{-2}	pounds per kWh
NO _x	0.2×10^{-2}	pounds per kWh
Particulates	0.08×10^{-2}	pounds per kWh

Waste water and solid waste (ash) removal are handled in a conventional manner.

7.5 Economic Data

This type of electric power plant is best suited for very large base load service and will be in the 1,000 MW_e or more size range.

Since this technology is relatively undeveloped, cost figures are necessarily tentative. It is important to emphasize the inherent tentativeness of cost data for any undeveloped technology. This situation is the result of the fact that engineering capital costs are a function of the costs of the component equipment installed in the plant. These equipment costs are manipulated to "factor in" additional cost elements such as installation, site preparation, engineering fee, interest, etc. In the case of the MHD plant, much of the equipment cannot be specified in sufficient detail to give hard equipment costs. As a matter of fact, some materials with the required heat resistance, etc. are not yet known. A recent estimate for the capital cost of a 1900 MW_e plant is \$2,090 million. This capital cost is composed of the categories listed in Table 7-2. This may be normalized by dividing by 34 since the plant is expected to produce 37.5×10^{12} Btus of electricity each year.

TABLE 7-2
CAPITAL COST COMPONENTS FOR MHD POWER PLANT

COMPONENT	COST DOLLARS
major plant components	\$ 174,700,000
balance of plant	809,900,000
contingency	196,900,000
escalation	395,700,000
interest	513,100,000
total capital cost	\$2,090,300,000

Note: Balance of plant includes cooling towers, DC to AC inverters, and site labor.

Source: Corman, J.C. et al., 1976, Energy Conversion Alternatives Study - ECAS - General Electric Phase I, Final Report Volume II, Part 3, NASA-ERDA-NSF, Washington, D.C.

For the purposes of the SEAS-AEAR data book, the value of the construction cost (major plant components and the balance of plant) is used as input data to the SEAS Model. The construction cost is \$985 million.

7.6 References

- Corman, J.C. et al., 1976. Energy Conversion Alternatives Study - ECAS - General Electric Phase I, Final Report, Volume II, Part 3, NAS-ERDA-NSF, Washington, D.C.
- Hoover, D.Q. et al., 1966. Feasibility Study of Coal Burning MHD Generation Volume I, Department of the Interior - Office of Coal Research, Washington, D.C.
- Mannal C. and N.W. Mather, 1969. Magnetohydrodynamics, Standard Handbook for Electrical Engineers, New York.

8.0 COAL-OIL MIXTURE

8.1 Characteristics of Coal-Oil Mixture Preparation Plants

A coal-oil mixture (COM) is a slurry-like suspension of pulverized coal in oil that can be handled and burned like residual (No. 6) oil. If COM were used in combustion units that now burn residual oil alone, demand for coal could be increased and residual oil requirements could be substantially reduced. In fact, the total annual U.S. requirement of 900 million barrels of residual oil can be reduced to 528 million barrels by using a 50 percent* COM wherever residual fuel oil is used (Pruce, 1980).

It is believed that both industrial and electric utility users of COM will prefer to receive COM as they presently receive No. 6 fuel oil (to avoid the obvious inconvenience or lack of space for on-site mixing). Therefore, COM commercialization is likely to develop most rapidly where a market exists to justify the construction of a large preparation plant (20,000 tons per day) such as the one depicted in Figure 8-1.

When a large central preparation/distribution COM facility is built, it is most likely to include an elaborate coal beneficiation capability. Coarsely beneficiated coal would be delivered by unit train (10,000-ton payload) to a rotary car dump and then moved to a transfer house. From the transfer house, the coal would be either brought to a live or dead storage stockpile through a stacker/reclaimer or to the COM circuit (or the coal beneficiation circuit) through a 24-hour capacity process surge silo.

*A 50 percent mixture is at the limit where material handling and combustion problems are acceptable.

Source: George, Thomas J., 1978. A Commercial Coal-Oil Preparation Facility: Concepts and Economics Assuming a 50-Percent Mixture (33 Million Barrels per Year). U.S. Department of Energy, Morgantown, West Virginia Process Evaluation Office. Report No. FE/EES-79/2.

FIGURE 8-1
SCHEMATIC OF A LARGE COM PREPARATION PLANT

Coal in the COM circuit is first passed through hoppers which have a 4-hour holdup. From the hoppers, the coal is moved through a pulverizer (e.g., a vertical roll mill) which reduces the coal to 90 percent through 200 mesh. Cyclone separator feeders then transmit the coal for mixing with oil. Either continuous or batch mixing may be employed. (Batch mixing appears the most likely for the initial facilities.) Batch mixing consists of filling a tank to a specified level with oil and then blending in coal until a second level is reached which represents the desired mixture.

The oil and the COM would be stored in 100,000 barrel tanks. It is assumed that each tank (25 in all) might be used to store either oil or COM on a rotating basis. This shared storage offers flexibility and uninterrupted deliveries during, for example, scheduled shutdowns. It is assumed that the COM is delivered through the existing No. 6 fuel oil distribution system. It is also assumed that additives to maintain the suspension will not be necessary due to naturally occurring stabilizers in the oil.

8.1.1 Constraints

The primary factor for the present attractiveness of COM conversion is the large differential in coal and oil prices. Increased coal prices would reduce the attractiveness of COM conversion unless the equivalent cost of coal continues to lag the cost of oil. Thus, very detailed marketing studies must be undertaken prior to determining the location of a COM preparation plant. In fact, incentives for both the producer and user may be required to fully realize the value of COM.

In addition to any potential marketing obstacles that must be weighed before constructing a central COM facility, the siting of a large COM preparation plant must obey several environmental mandates.

Because the potential exists for fugitive dust and hydrocarbon emissions, COM plants come under scrutiny by Federal and local air pollution regulatory bodies. The discharge of water pollutants (e.g., greases and oils) are controlled by Federal and state water pollution regulations. Finally, because the potential for noise and accidents exists, the siting of COM preparation plants requires attention to land use and zoning regulations.

8.1.2 Resource Requirements

8.1.2.1 Fuel. The constituents of the COM in this study are assumed to be 50 percent (by weight) eastern bituminous coal that has been coarsely beneficiated and 50 percent No. 6 fuel oil. Table 8-1 summarizes the characteristics of these fuels.

For a 33 million-barrel (6.24×10^6 ton) per year producing facility (operating 312 days per year and 20 hours per day), the required throughput of coal and oil is 10,000 tons per day and 0.059 million barrels per day, respectively.

8.1.2.2 Energy. The annual requirement for electricity to operate a batch mixing preparation plant has been estimated at 9.19×10^7 kWhr (George, 1978). It was assumed that dry grinding is employed.

8.1.2.3 Land. An estimate for the land required to site a large preparation plant was obtained from Bechtel (1978) data on petroleum bulk storage stations. For a 500 thousand barrel capacity tank farm, 50 acres would be occupied. Assuming a linear scale-up, a 2.5 million barrel COM preparation plant would require about 250 acres. An additional 11.5 acres would nominally be required for a 60,000 ton coal storage stockpile.

TABLE 8-1

CHARACTERISTICS OF COAL AND OIL INPUTS
FOR COAL-OIL MIXTURE

FUEL	% ASH	% SULFUR	HEAT CONTENT (BTU/LB)	API GRAVITY	SP. GRAVITY	SALE PRICE*
No. 6 Oil	0.5	1	18,800	23°	-	\$11.10/bbl
Coal	5.5	2	13,000	-	1.20	\$27/ton

*Costs are based on 1978 indices.

Source: George, Thomas J., 1978. A Commercial Coal-Oil Preparation Facility: Concepts and Economics Assuming a 50-Percent Mixture (33 Million Barrels per Year). U.S. Department of Energy, Morgantown, West Virginia, Process Evaluation Office. Report No. FE/EES-79/2.

8.1.2.4 Water. The demand for water to support the COM facility is assumed to be minor, reflecting needs for dust-suppression during coal handling and coal storage, and for personnel support.

8.1.2.5 Cost. Tables 8-2 and 8-3 detail the capital and operating cost associated with a COM batch mixing facility, respectively.

8.1.2.6 Personnel. To gain an indication of the manpower level required to construct a large COM preparation plant, Bechtel (1978) data on the manpower needed to construct a similarly sized petroleum bulk storage station was used. These data, scaled linearly are presented in Table 8-4.

George (1978) estimated the manpower requirements to operate and maintain a large COM preparation plant. The number of operators per shift for a batch mixing facility is estimated to be 13. The number of maintenance personnel is estimated to be 76. It is assumed that about 15 percent of the personnel would be supervisory.

8.1.3 Residuals

8.1.3.1 Air Pollutants. Particulate and hydrocarbon emissions would be the major air pollutants from COM preparation plants. However, emission rates would be highly dependent on local conditions and operating modes. For example, factors affecting the rate of evaporative losses include: the true vapor pressure of the liquid stored, temperature changes in the tanks, height of the vapor space, tank diameter, schedule of tank filling and emptying, mechanical condition of tank and seals, type of tank, and type of paint applied to outer surface (U.S. Environmental Protection Agency, 1975).

TABLE 8-2

TOTAL INVESTMENT REQUIREMENTS FOR A COM BATCH MIXING FACILITY

BATTERY UNIT	COST (1978 DOLLARS)
Rotary car dump	\$ 6,685,100
Stacker/reclaimer	6,638,300
Coal stockpile*	1,662,200
Process surge coal silo	3,138,500
Pulverizing	22,130,900
COM preparation	2,428,200
Oil-COM storage	19,992,200
Steam plant	100,000
Plant facilities	6,277,500
Plant utilities	<u>5,179,000</u>
Subtotal plant cost (including insurance and tax bases)	\$ 74,231,900
Interest during construction	\$ 8,907,800
Working Capital	
Plant	\$ 8,314,000
Fuel Inventory**	\$ <u>36,506,400</u>
Total	127,960,100

*Assumes a 60-day coal stockpile

**Assumes a 15-day oil inventory

Source: George, Thomas J., 1978. A Commercial Coal-Oil Preparation Facility: Concepts and Economics Assuming a 50-percent Mixture (33 Million Barrels per Year). U.S. Department of Energy. Morgantown, West Virginia Process Evaluation Office. Report No. FE/EES-79-2.

TABLE 8-3

ESTIMATED ANNUAL OPERATING COST FOR
A COM BATCH MIXING FACILITY

ITEM	COST (1978 Dollars)
Raw Materials and Utilities	\$ 2,845,200
Direct Labor	839,600
Plant Maintenance (Materials and Manpower)	3,693,600
Overhead	4,243,100
Taxes, insurance, and depreciation	\$ <u>6,384,000</u>
Total	\$ 18,005,500

Source: George, Thomas J., 1978. A Commercial Coal-Oil Preparation Facility: Concepts and Economics Assuming a 50-percent Mixture (33 Million Barrels per Year). U.S. Department of Energy, Morgantown, West Virginia Process Evaluation Office. Report No. FE/EES-79/2.

TABLE 8-4

MANPOWER REQUIREMENTS FOR THE CONSTRUCTION OF A
500,000 BARREL PETROLEUM BULK STORAGE STATION

MANPOWER	REQUIREMENT (IN MAN-YEARS*)
Nonmanual, technical	11.0
Nonmanual, nontechnical	1.5
Manual	<u>47.5</u>
Construction Total	60.0

*Assumes 2000 man-hours equals a man-year

Source: Bechtel Corporation, 1978. Energy Supply Planning Model.
San Francisco, California.

Fugitive dust emission characteristics are a function of local meteorological events as well as the control features involved.

8.1.3.2 Water Pollutants. Runoff from the coal stockpiles and from the oil-COM storage areas will contain a wide variety of water pollutants. In addition, leaks and spills will occur. Data quantifying the amounts of these pollutants and the magnitudes of their potential impacts are not available at this time because they are site specific.

8.1.3.3 Solid Waste. The amount of solid waste generated by a COM preparation facility will be negligible since the coal that is used is assumed to be coarsely beneficiated.

8.2 Characteristics of Coal-Oil Mixture Combustors

Steam boilers are the greatest users of oil in the U.S. - about 3.5 quads and 0.8 quads are used annually by utilities and industries, respectively. It has been estimated that the use of a 50-50 coal-oil mixture (COM) by candidate boilers could save about one quad (or about 528 million barrels of oil) per year (Pruce, 1980).

Since a boiler which has a longer remaining life has a lower amortized capital cost for COM conversion, the newer boilers (those less than 20 years old) are more profitable to convert. Boilers less than 20 years old account for 85 percent of the capacity of oil-designed units and 50 percent of the capacity of coal-designed units. The large (greater than 200 MW_e capacity) coal-designed boilers are generally older than 20 years. Conversely, the large oil-designed

boilers are generally newer units and, therefore, they are prime targets for COM combustion retrofitting (MITRE, 1980).

It is assumed that a majority of the candidate electric utility boilers would rather receive COM as they now receive No. 6 fuel oil to avoid the obvious inconvenience (or physical constraint) of on-site preparation. Within this context, the following discussion summarizes the modifications needed to burn COM. In general, wear-resistant alloys and enlarged orifices for the boiler will be needed to prevent deterioration and to ensure a compatible viscosity range. Existing fuel train pumps may have to be replaced with wear-resistant rotary gears or progressive-cavity-type pumps. Valves will also have to be replaced with full-bore, ball-type units for control purposes. Additional sootblower capacity may be needed to prevent the buildup of residue. Particulate and sulfur oxide abatement technology (i.e., an electrostatic precipitator and flue gas desulfurization) may be required to control these emissions. The capacity of the bottom ash removal system may need to be augmented. Although the existing oil unloading system can be used with the COM, an independent COM storage and handling circuit would be desirable to achieve dual fuel capacity (so that oil can be burned periodically to minimize the effect of derating).

8.2.1 Constraints

Successful combustion of COM has been achieved in short-term tests in existing boilers, confirming the feasibility of burning COM in retrofitted units. However, burning COM continuously for extended periods of time with reasonable reliability is still under investigation to determine the extent to which this technology is economically practical.

Probably the major obstacle confronting widespread acceptance of COM combustion is environmental. Bergman et al. (1979) succinctly pointed this out when they stated that "it is a safe assumption that in most instances coal will only be employed . . . as the 'fuel of last resort', as long as more convenient 'clean fuels' remain obtainable. The prevailing uncertainties associated with the field of air pollution control represent formidable barriers to increased . . . coal utilization. The negative experiences many electric utilities have incurred with flue gas desulfurization technology have tended to reinforce these fears. The environmental regulations associated with coal combustion are well known. However, it appears that these regulations are destined to [remain] or grow even more stringent in the immediate future, thereby further increasing the risks associated with making heavy financial commitments"

8.2.1.1 Air Pollution. Because the Nation's goal is for coal-firing to replace oil-firing, COM must be considered an interim fuel to be used only by existing boilers. The U.S. Environmental Protection Agency (1979) has ruled that existing oil-fired steam generators that switch to COM and have a thermal input of more than 250×10^6 Btu/hour will be subject to Subpart D of the New Source Performance Standards for New Stationary Sources (i.e., the Standards of Performance for Fossil Fuel-Fired Steam Generators).^{*} Subpart D places a limit on particulates (P) of $0.10 \text{ lb}/10^6 \text{ Btu}$, on sulfur dioxide (SO_2) emissions of $1.2 \text{ lb}/10^6 \text{ Btu}$, and on nitrogen oxide (NO_x) emissions of $0.70 \text{ lb}/10^6 \text{ Btu}$. Subpart D for liquid fossil fuel combustion calls for the same limit on P, but for SO_2 the standard is $0.80 \text{ lb}/10^6 \text{ Btu}$

^{*}Modification to boilers of lower rating will remain subject to local laws (i.e., SIPs).

and for NO_x it is $0.30 \text{ lb}/10^6 \text{ Btu}$. Thus, the standard for COM combustion is the weighted average of the individual limits for coal and oil based on their heating values. For example, the emission standard for SO_2 for a 50-50 COM fuel composed of oil having a heating value of 18,600 Btu/lb and coal having a heating value of 13,000 Btu/lb is $0.93 \text{ lb}/10^6 \text{ Btu}$.

8.2.1.2 Solid Waste. Ash generated by COM units should resemble a mixture of ash residue from coal-fired and oil-fired boilers. The leachates from this ash may contain low levels of toxic substances but their concentrations may exceed acceptable levels under the Resource Conservation and Recovery Act (RCRA). Criteria for some solid wastes have recently been proposed, and specific regulations for fly ash and other boiler solids are forthcoming. Whatever Federal criteria are issued in the future, it is reasonable to assume that current local solid waste regulations will still obtain. Section 1008(a) of RCRA provides strict instructions to the States on waste disposal management.

8.2.1.3 Water Pollution. The Clean Water Act established a regulatory program, jointly administered by the U.S. Environmental Protection Agency and the States, using water quality levels and technology-based standards to meet the national goal of eliminating the discharge of water pollutants by 1985. Standards for the steam electric power plant point-source category, applicable to all fuel types -- coal, oil, natural gas, and nuclear -- have been set which regulate both chemical and thermal water discharges.

8.2.1.4 Chemical Discharges. There are three different technology-based standards which limit the allowable concentration of chemical pollutants from existing steam electric power plants. The BPT standard, derived from "best practicable control technology

currently available," is the least stringent standard. The BAT standard, derived from "best available technology economically achievable," requires the highest level of technological control. The 1977 Clean Water Act Amendments added the "best conventional pollution control technology" (BCT) which lies between BPT and BAT standards in stringency. The compliance deadline for the various standards is July 1, 1977 for BPT; July 1, 1984 for BCT; and July 1, 1984 for BAT. All new plants (defined as those where construction commenced after March 4, 1974) must comply with New Source Performance Standards (NSPS) at the time of start-up.

A summary of the U.S. Environmental Protection Agency promulgated chemical effluent limitations is shown in Table 8-5. According to the 1977 Amendments and the June 1976 National Resources Defense Council (NRDC) Consent Decree, U.S. Environmental Protection Agency must still promulgate BCT standards for conventional pollutants and must expand the scope of the BAT standard by addressing 129 toxic or priority pollutants.

8.2.1.5 Thermal Discharges. The thermal discharge limitations established by the U.S. Environmental Protection Agency are designed to reduce the amount of waste heat discharge to receiving water bodies. A summary of the U.S. Environmental Protection Agency promulgated thermal discharge limitations is shown in Table 8-6. Because of the excessive capital costs and long lead times involved for the installation of closed cycle cooling systems, no thermal limitations were prescribed for existing small (less than 25 MW_e capacity) or old (500 MW_e or greater and operational before January 1, 1970; or 25 to 499 MW_e and operational before January 1, 1974) unit categories. Existing large base-load generating units must achieve a zero heat discharge standard (except for blowdown) by July

TABLE 8-5

SUMMARY OF CHEMICAL EFFLUENT LIMITATIONS
FOR STEAM ELECTRIC POWER PLANTS

Source	Pollutant	Effluent Limitations* (mg/l)		
		BPT (1977)	BAT (1984)	NSPS
● All Sources	pH** Polychlorinated biphenols	6.0 to 9.0 No discharge	6.0 to 9.0 No discharge	6.0 to 9.0 No discharge
● Low Volume Wastes	Total Suspended Solids Oil and Grease	30 (100 max) 15 (20 max)	30 (100 max) 15 (20 max)	30 (100 max) 15 (20 max)
● Bottom Ash Transport Water	Total Suspended Solids Oil and Grease	30 (100 max) 15 (20 max)	30 (100 max) 15 (20 max)	30 (100 max) 15 (20 max)
● Fly Ash Transport Water	Total Suspended Solids Oil and Grease	30 (100 max) 15 (20 max)	30 (100 max) 15 (20 max)	No discharge 15 (20 max)
● Metal Cleaning Wastes	Total Suspended Solids Oil and Grease Copper Iron	30 (100 max) 15 (20 max) 1.0 (1.0 max) 1.0 (1.0 max)	30 (100 max) 15 (20 max) 1.0 (1.0 max) 1.0 (1.0 max)	30 (100 max) 15 (20 max) 1.0 (1.0 max) 1.0 (1.0 max)
● Boiler Blowdown	Total Suspended Solids Oil and Grease Copper Iron	30 (100 max) 15 (20 max) 1.0 (1.0 max) 1.0 (1.0 max)	30 (100 max) 15 (20 max) 1.0 (1.0 max) 1.0 (1.0 max)	30 (100 max) 15 (20 max) 1.0 (1.0 max) 1.0 (1.0 max)
● Once-Through Cooling	Chlorine-free available	0.2 (0.5 max)	0.2 (0.5 max)	0.2 (0.5 max)

TABLE 8-5 (Concluded)

SUMMARY OF CHEMICAL EFFLUENT LIMITATIONS
FOR STEAM ELECTRIC POWER PLANTS

Source	Pollutant	Effluent Limitations* (mg/l)		
		BPT (1977)	BAT (1984)	NSPS
● Cooling Tower Blowdown	Chlorine-free available	0.2 (0.5 max)	0.2 (0.5 max)	0.2 (0.5 max)
	Zinc	No limitation	1.0 (1.0 max)	None detectable
	Chromate	No limitation	0.2 (0.2 max)	None detectable
	Phosphorous	No limitation	5.0 (5.0 max)	None detectable
	Other corrosion inhibitors	No limitation	Case by Case	None detectable
● Area Runoff	Total Suspended Solids	50***	50	50

Notes: *Limitations are expressed as concentrations, mg/l, except for pH. Quantity discharge is limited to concentration limit x flow. For BAT, bottom ash limit is x flow/12.5 and the NSPS limit for bottom ash is x flow/20. In some cases, limits are available for the maximum allowable daily discharge for any one day.

**Applicable to all sources except once-through cooling.

***Area runoff limits are concentration limits only.

Source: Code of Federal Regulations, 1979. Title 40, Part 400 et seq.

TABLE 8-6

SUMMARY OF THERMAL DISCHARGE LIMITATIONS FOR STEAM ELECTRIC POWER PLANTS

The compliance deadline for existing plants is July 1, 1981. Extensions may be granted to no later than July 1, 1983. Plants whose construction began on or after March 4, 1974 must comply with the new source standards at the time of the start-up.

Existing Generating Units

500 MW_e and greater

Operation commenced before January 1, 1980	No Limitation
--	---------------

Operation commenced on or before January 1, 1970	No Discharge*
--	---------------

25 MW_e to 499 MW_e

Operation commenced before January 1, 1974	No Limitation
--	---------------

Operation commenced on or after January 1, 1974	No Discharge
---	--------------

Less than 25 MW _e	No Limitation
------------------------------	---------------

New Sources

(all unit categories)	No Discharge**
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Notes: Zero discharge limitations allow for blowdown from the cold-side of the system.

*Exceptions may be granted on a case-by case basis for units in systems for less than 150 MW_e capacity, units with cooling ponds or cooling lakes, units without sufficient land available, units with blowdown TDS 30,000 mg/l or greater, and neighboring land within 500 ft. of cooling tower(s), and units where a potential hazard to commercial aviation would exist.

**Waivers may be granted based upon a demonstration of excessive stringency according to Sec. 316 (a).

Source: Code of Federal Regulations, 1979. Title 40, Part 400 et. seq.

1, 1981. A zero heat discharge requirement effectively means the installation of an off-stream cooling system.

In summary the selection of COM-fired units will be critical. COM will be used in existing boilers where air pollutant emissions will be regulated by the Federal NSPS for fossil-fired steam electric generating stations or local SIPs. In addition, these facilities must not cause local ambient air quality standards to be exceeded. Finally, appropriate engineering, hydrogeological, environmental, and socioeconomic considerations must be taken into account to the selection of the waste disposal site. In actuality, COM facilities may not be located in urban areas since suitable local solid waste disposal sites may not be economically available due to local ordinances, land availability, and/or RCRA.

8.2.2 Resource Requirements

8.2.2.1 Fuel. A typical 300 MW_e plant burning No. 6 fuel oil, operating with a thermal efficiency of 35 percent and with a capacity factor of 55 percent, would consume about 2.25×10^6 barrels (14.2×10^{12} Btu) of fuel oil per year (assuming a heat content of 6.3×10^6 Btu per barrel). The equivalent amount of a 50-50 (by weight) COM to provide 14.2×10^{12} Btu per year of heat input is 2.4×10^6 barrels per year (assuming its heat content is 5.9×10^6 Btu per barrel). Table 8-7 shows the characteristics of a typical 50-50 COM fuel.

8.2.2.2 Energy. Energy is needed during the operation of a COM-fired boiler to drive the pumps of the fuel train and pollution control devices. Table 8-8 gives the energy requirements (in terms

TABLE 8-7
CHARACTERISTICS OF A 50-50 COM FUEL

Heat Content	15,930 BTU per lb
Density	8.82 lb per gal
Sulfur Content	1.5 percent
Ash Content	3 percent
Cost (1980 dollars)	\$2.30 per 10 ⁶ BTU input

Source: George, Thomas J., T.C. Campbell and P.D. Bergman, 1980.
Coal-Oil Mixtures: A Good Idea from DOE. Coal Mining
and Processing, Vol. 16, No. 3.

of percentage of the total plant output) associated with a typical
COM-fired plant.

8.2.2.3 Land

If COM is produced off-site in a centralized COM preparation plant and delivered to the boiler through its existing oil receiving system, COM conversion at the plant will probably not require extensive additional land. One modification that may be necessary but may not require additional space is the rerouting of feed lines to avoid areas where settling may take place. Another need is for an independent COM storage and pumping system. This will not require additional property if the layout of the existing oil storage and pumping system will accommodate the modification. The siting of a landfill for the disposal of waste products may require additional land. The amount of land required for this application is, however, not estimated since it is highly site specific.

TABLE 8-8

ENERGY REQUIREMENTS FOR THE OPERATION OF POLLUTION
CONTROL EQUIPMENT AND FUEL TRAIN DEVICES EXPECTED
BY A TYPICAL COM-FIRED PLANT

PROCESS	PERCENT OF ENERGY PRODUCED
Air Pollution Control*	
SO ₂ Control	
Flue Gas Desulfurization	
lime wet scrubber	3.5
limestone wet scrubber	4.0
Particulate Control	
Mechanical Collectors	
multiple cyclones	2.0-0.9
Electrostatic Precipitators	0.3
NO _x Control	
Combustion Modifications	0-0.6
Water Pollution Control*	
Chemical Pollution Control	
wastewater treatment plant	0.01
evaporative ponds	0.04
complete treatment and reuse	0.2
Thermal Pollution Control	
open cycle	0
closed cycle	
cooling ponds	1.0
mechanical draft towers	2.5
Noise Control*	<0.1
Soot Control and Ash Handling	
sootblowers	NA
ash handling and disposal	Site Specific
Fuel Train	NA

*Assumes that the requirements would be similar to those which are needed by an oil-fired power plant.

Source: U.S. Department of Commerce/U.S. Environmental Protection Agency, 1977. Energy Consumption of Environmental Controls: Fossil Fuel Steam Electric Generating Industry.

8.2.2.4 Water. It has been observed that a COM boiler needs an additional gallon of water per hour per MW_e more than that consumed by an existing oil-fired boiler (MITRE, 1979). A typical 80 MW_e oil-fired boiler consumes about 18,780 gallons (0.0576 acre-feet) per hour (U.S. Energy Research and Development Administration; 1977).

8.2.2.5 Capital. George, Campbell, and Bergman (1980) have estimated that the cost (in 1980 dollars) to retrofit a large oil boiler to COM-firing would be equivalent to \$0.20 per million Btu's of fuel consumed. Their analysis included stack gas cleanup, boiler retrofit, plant facilities, plant utilities, sodium bicarbonate requirements, interest during construction, and working capital.

MITRE (1980) estimate that the annual operating and maintenance cost (in 1980 dollars) for a 300 MW_e boiler is about \$4.5 million.

8.2.2.6 Personnel. Published data on the number (and expertise) of persons required to modify an existing oil-fired plant to use COM is not readily available. Nevertheless, it is expected that the number will be relatively small. The estimated construction time for COM conversion is 12-14 months (MITRE, 1980). The estimated boiler downtime is 2-4 months (MITRE, 1980).

The number of personnel required for operations and maintenance should be similar to that used in an oil-fired power plant. Requirements for the operation and maintenance of an oil-fired power plant estimated by Bechtel (1978) are shown in Table 8-9.

8.2.3 Residuals

8.2.3.1 Air Pollutants. The gross amount of air pollutants from COM-fired steam electric plants will be a weighted function of

TABLE 8-9

OPERATION AND MAINTENANCE MANPOWER REQUIREMENTS
FOR AN 800 MW_e OIL-FIRED POWER PLANT

MANPOWER TYPES	MANPOWER (in man years)
nonmanual, technical	31.7
nonmanual, nontechnical	36.5
manual	76.2
Total	144.4

Source: Bechtel Corporation, 1978. Energy Supply and Planning Model.
San Francisco, California.

both the characteristics and throughput quantities of the coal and oil components of the COM fuel. In the case of three of the criteria pollutants - particulates, sulfur oxides, and nitrogen oxides - the controlled (or net) amounts will be set by the NSPS. For this analysis, it was assumed that the sulfur content of the coal and oil were 2 percent and 1 percent, respectively, and the ash contents were 5.5 percent and 0.5 percent, respectively. Emission rates given by the U.S. Environmental Protection Agency (1975) for bituminous coal and oil combustion and used in this analysis are presented in Table 8-10.

8.2.3.2 Water Pollutants. Reliable information on the characteristics of water pollutants discharged from a COM-fired boiler of large size is not currently available in the literature.

8.2.3.3 Solid Waste. The amount of scrubber sludge produced is highly dependent upon the size of the plant, fuel composition, type of FGD system installed (i.e., regenerative or nonregenerative), and the removal efficiency of the scrubber.

With regard to ash generation, it is believed that for COM combustion, fly ash will account for about 80 percent of the total ash (Rodriguez and Sell, 1979). Nevertheless, during particulate collection the quantity of fly ash collected for disposal is estimated to be only a small fraction of the total wet solid waste.

As with the characteristics of water pollutants, reliable information on solid waste generation from COM combustion in a large boiler is not currently available in the literature.

8.3 References

Bechtel Corporation, 1978. Energy Supply Planning Model. San Francisco, California.

TABLE 8-10

EMISSION FACTORS FOR BITUMINOUS COAL AND
RESIDUAL OIL COMBUSTION WITHOUT CONTROL EQUIPMENT

POLLUTANT	FACTOR	
	BITUMINOUS COAL (lb/ton)	RESIDUAL OIL (lb/10 ³ gal)
Particulates	16(A)*	8
Sulfur Oxides	38(S)**	159(S)**
Carbon Monoxide	1	3
Hydrocarbons	0.3	2
Nitrogen Oxides	18	105

*A is the ash content in percent

**S is the sulfur content in percent

Source: U.S. Environmental Protection Agency, 1975. Compilation of
Air Pollution Emission Factors. EPA Publication Number
No. AP-42.

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9.0 ELECTRIC TRANSMISSION LINES

9.1 Characteristics of Transmission Lines

Transmission lines transport electricity from power plants to load centers, such as houses, stores, etc., where the electric energy is demanded and consumed. Almost all transmission lines in the U.S. are designed for alternating current (AC), but direct current (DC) transmission is also feasible. Standard voltages for American AC lines are 69 kilovolts (kv), 115 kv, 138 kv, 161 kv, 230 kv, 345 kv, 500 kv, and 765 kv (General Electric Company, 1975 and Federal Power Commission, 1976). In 1952, the first 765 kv line began operating. Test facilities exist for future transmission lines with voltages up to 2200 kv (Miller and Kaufman, 1978).

Both 345 kv AC and 500 kv AC transmission lines are discussed in this report. The coefficients used apply to 500 miles of single circuit line with three conductors.

The Bechtel Corporation (1978) specifies an efficiency (kWh output divided by kWh input) of 82 percent for 500 miles of 345 kv AC line, resulting from an energy loss of about 4 percent compounded per 100 miles of transmission line. An efficiency of 89 percent for 500 miles of 500 kv AC line results from an energy loss of about 2 percent compounded per 100 miles and an additional two percent loss at a step-down transformer at the end of the line. The step-down transformer converts the 500 kv electric current to a lower voltage.

In general, the energy efficiency of a transmission line is positively associated with its voltage. For example, Bechtel describes a 765 kv AC line where energy losses are only one percent per hundred miles. Although most of the circuit miles in the U.S. today consist

of voltage lines of 345 kv or less, the national average energy efficiency for transmission is 90 percent* (Table 9-1). This is due to the fact that the typical distance from power plant to load center is only about 100 miles.

Bechtel assumes that the 345 kv line serves 600 MW_e and the 500 kv line serves 1,200 MW_e of plant capacity, both operating at a capacity factor of 0.65. The total annual energy output for the transmission lines depends on the number of kilowatt-hours (kWh) served. Thus, the annual output for the 345 kv line is 9.6×10^{12} Btus and is 20.8×10^{12} Btus for the 500 kv line.

9.2 Constraints

Historically, transmission lines have been subject to regulatory constraints at the federal and state level. With the passage of the National Environmental Policy Act (NEPA) of 1969 (PL 91-190), Federal regulation increased substantially. NEPA requires that environmental impact statements (EIS's) be prepared for any federal action having a significant environmental impact.

More than a dozen federal agencies exercise authority over some aspect of transmission lines. The Department of the Interior requires EIS's for lines cutting through any of its lands (e.g. National Parks). Similarly, any line passing through a National Forest must be approved by the Department of Agriculture. Power lines connecting a proposed nuclear power plant to the applicable transmission grid must be subjected to an environmental evaluation conducted by the Nuclear Regulatory Commission.

*This efficiency applies only to electricity that is commercially sold; thus, it does not include on-site industrial electricity generation.

TABLE 9-1

PRIMARY ENERGY EFFICIENCY OF ELECTRIC TRANSMISSION
(Including Distribution)

YEAR	UTILITY PRODUCTION (10 ⁹ kWh)	UTILITY SALES (10 ⁹ kWh)	EFFICIENCY
1950	329	291	0.884
1960	753	686	0.911
1970	1526	1392	0.912
1971	1610	1469	0.913
1972	1750	1595	0.912
1973	1856	1713	0.923
1974	1865	1706	0.915
1975	1917	1730	0.902
1976	2036	1834	0.900

Note: Industrial on-site electricity generated is not included in these figures.

Source: Federal Power Commission, 1976. Annual Reports, 1950-1976.
Washington, D.C.

The Federal Aviation Administration requires a permit for any structure over 200 feet high located close to designated airports. Any transmission line crossing navigable waters or a tributary thereof must be approved by the U.S. Army Corps of Engineers. Furthermore, a permit must be obtained from the Coast Guard for any line crossing a bay, inlet, or harbor.

Transmission lines within the right-of-way (ROW) of Interstate Highways must be approved by the Federal Highway Administration (FHWA). In the past, however, the FHWA has had a general policy against this use of rights-of-way.

The Federal Noise Control Act (PL 92-523) recommends ambient noise standards which may be adopted by states. According to Miller and Kaufman (1978), this recommendation may pose a constraint against the development of very high voltage lines which produce noise under certain climatic conditions that "could cause at least some annoyance to some people."

9.3 Natural Resource Consumption

As noted above, a certain amount of energy is lost in the transmission of energy. The model 345 kv line loses 210×10^9 Btus of electricity per 10^{12} Btus output, while the 500 kv line loses 120×10^9 Btus per 10^{12} Btus output. Assuming a 34 percent thermal efficiency in the power plant, this implies that the 345 kv line consumes 617×10^9 Btus of fuel per 10^{12} Btus output, while the 500 kv line uses 352×10^9 Btus per 10^{12} Btus output.

A report by General Electric specifies ROW widths of 150 feet for 345 kv lines and 175 feet for 500 kv lines. These rights-of-ways occupy 18.18 acres per mile of 345 kv line and 21.21 acres per mile

of 500 kv line. Thus, for 500 mile lengths, the 345 kv line ROW uses 9091 acres and the 500 kv line ROW uses 10,606 acres.*

To convert these land use figures to a 10^{12} Btus output basis, the total acreage for the 500 mile lines was divided by total annual energy output. For the 345 kv line, 9,091 acres divided by 9.6×10^{12} Btus equals 447 acres per 10^{12} Btus annual output. Similarly, for the 500 kv line, 10,606 acres divided by 20.8×10^{12} Btus results in 509.9 acres per 10^{12} Btus annual output.

These land use coefficients, as calculated for the model, apply only to sets of 500 mile lines, each serving a power plant with a .65 capacity factor and a particular MW_e rating. Thus, these coefficients are of limited use.

9.4 Residuals

No quantitative data were found for residuals which could be specified in terms of tons per 10^{12} Btus. Some air pollution is produced, however, by the corona of transmission lines. Miller and Kaufman (1978) state that the corona may generate some chemical oxidants, including nitrogen oxides, but mainly ozone. Experts testifying at hearings before the New York Public Service Commission generally agreed that "the ozone produced by 765 kv transmission lines would be far too little to have any significant biological effect."

*By comparison, Bechtel (1978) assumes that 500 miles of 345 kv line ROW occupy 9100 acres and 500 miles of 500 kv line ROW occupy 10,650 acres.

Transmission line coronas may also produce audible noise under certain weather conditions, such as fog and precipitation. In general, the higher the voltage of the line, the greater the amount of noise generated. As Miller and Kaufman (1978) stated, "Most 345 kv and lower voltage lines are only barely audible even in foul weather. Existing 765 kv lines are inaudible or barely audible in fair weather, but they may sometimes be heard for several hundred feet laterally in fog or precipitation... The noise levels are well below those needed to cause hearing damage but could cause at least some annoyance to some people" (Miller and Kaufman, 1978). The corona may also interfere with radio and TV reception. Corona discharge may be minimized by using larger diameter conducting wires or bundled collectors (Dawes and Noland, 1967).

Another class of environmental impacts is due to the electric and magnetic fields of transmission lines (Table 9-2). Higher voltage lines will tend to interfere with some cardiac pacemakers. Although few, if any, pacemakers would be disturbed by 345 kv lines, it is very likely that at least some pacemakers would be disrupted by 765 kv lines. However, Miller points out that people with pacemakers driving in cars under transmission lines will not be affected since the metal in the car body acts as a shield against the electric field.

Electric fields from transmission lines may also cause electric shocks in some circumstances to persons nearby. The risk of such shock is greater for higher voltage lines. Field strengths of 6 kv per meter, which may result in annoying transient spark discharges, occur for 345 kv lines and up (Table 9-3). In general, the threshold level for annoying shocks depends on whether the subject is grounded and whether any object being touched is grounded.

TABLE 9-2

POSSIBLE IMPACTS OF TRANSMISSION LINES ON THE ENVIRONMENT

EFFECTS OF CONSTRUCTION AND MAINTENANCE

- Clearing of land within right-of-way
- Clearing and maintenance of access roads
- Soil compaction and other physical damage due to construction activities
- Interference to agriculture due to tower structures
- Aesthetic impact of towers and lines

HAZARD OF ELECTRIC SHOCK FROM CONTACT WITH LINES

EFFECTS OF CORONA

- Radio and television interference
- Audible noise
- Production of ozone and oxides of nitrogen

EFFECTS OF ELECTRIC AND MAGNETIC FIELDS

- Fuel ignition by spark discharges
- Induced electric shocks (transient and steady-state)
- Biological effects of electric and magnetic fields
- Interference with cardiac pacemakers

Source: Miller and Kaufman, 1978. High Voltage Overhead.
Environment Magazine.

TABLE 9-3

ELECTRIC FIELD STRENGTHS OF SELECTED TRANSMISSION LINES

KV	CIRCUIT	NUMBER OF SUBCONDUCTORS	INCH DIAMETER OF SUBCONDUCTORS	MAXIMUM FIELD STRENGTHS (kv/meter) AT 3 FEET ABOVE GROUND
345	double	2	1.165	5 - 7
345	single	2	1.108	4.5 - 8
500	single	2	1.821	6 - 7
765	single	4	1.165	8 - 12

Source: Tell, R.A. et al., 1977. An Examination of Electric Fields Under Extra High Voltage Power Transmission Lines, EPA Office of Radiation Programs. Washington, D.C.

A survey by the New York State Agricultural Research Commission of 18 farmers in Ohio whose farms were crossed by 765 kv lines found that 14 of the farmers had not experienced any shocks due to the lines. One farmer had received a heavy shock from a tarpaulin covering a grain wagon during the rain and three others had experienced slight shocks once or twice (Miller and Kaufman, 1978).

Two other effects of electric fields are notable. At very high field strengths, plants with pointed leaves develop "burned" leaf tips. Also, there is a theoretical possibility that a spark strong enough to ignite gasoline could occur during refueling operations beneath a transmission line (Miller and Kaufman, 1978).

Finally, there is a good deal of controversy concerning possible biological impacts of power lines, including heart disease, high blood pressure, and hypertension. Articles in the May and November 1978 issues of Environment Magazine discuss biological hazards, some of which are claimed to occur to subjects up to one mile away from high voltage lines.

In 1975, there were 49 occupational deaths, about 26,700 injuries, and 188,740 lost workdays in SIC (Standard Industrial Code) 491, electric services (U.S. Bureau of Labor Statistics, 1975 and 1976). These figures include incidents in generating electricity as well as distributing it. Until it is known what percentage of these incidents are for transmission lines, occupational safety coefficients cannot be derived. A further problem is the fact that some transmission line accidents are recorded for SIC 493, combination electric and gas and other utility services.

9.5 Economic Data

Bechtel provided the engineering cost in 1978 dollars and materials and personnel requirements for building 500 miles of transmission line at 345 kv AC and 500 kv AC.* Construction costs and materials requirements were put on a per 10^{12} Btus annual output basis simply by dividing by the total annual energy output expressed in 10^{12} Btus. For example, the cost of non-manual technical labor for building a 500 kv line, \$614,000 per 10^{12} Btus annual output, was derived by dividing the absolute costs, \$12,770,000, by annual output, which is 20.8×10^{12} Btus (Tables 9-4, 9-5, and 9-6).

Comparison of the cost figures for the 345 and 500 kv AC transmission lines indicates that the 500 kv line is roughly 30 percent cheaper to build per Btu of annual output. However, this is true only for the assumptions given earlier concerning the MW_e capacities served by the lines. If the two lines were serving identical power plant capacities, the 345 kv line construction cost per Btu annual output would actually be less than that of the 500 kv line, other things being equal.** Moreover, the 500 kv line is 55 percent more expensive to build per mile of transmission line.

*Bechtel (1978) also provides these data for 230 kv AC, 765 kv AC, and 400 kv DC lines. A two year construction period is specified by Bechtel for all the different voltage transmission lines it assesses.

**This can be shown as follows: If the 500 kv AC and the 345 kv AC lines both serve 600 MW of power plant capacity, then the annual output of the 500 kv line would be $600,000 \times .65 \times 8760 \times .89 = 3.04 \times 10^9$ kWh, where 600,000 = plant capacity in kilowatts (kw), .65 = capacity factor, 8760 = number of hours in a year, and .89 = energy efficiency.

Using a conversion factor of 3413 Btus per kWh, the annual output of the 500 kv line is 10.4×10^{12} Btus. The construction cost of the 500 kv line is \$238.95 million, when this figure is divided by 10.4×10^{12} Btus, a total engineering construction cost of \$22,980,000 per 10^{12} Btus output is derived. This cost is more than 40 percent higher than the cost shown for the 345 kv line.

TABLE 9-4

MATERIALS USED IN CONSTRUCTION
(Per 10^{12} Btus Output)

MATERIALS	345 kv AC LINE (TONS)	500 kv AC LINE (TONS)
concrete (including cement)	2,810	1,830
steel	2,520	1,620
copper	90.9	127
aluminum	450	532
manganese	17.6	10.8
chromium	1.86	2.77
nickel	0.0229	0.138
cast iron	10.4	5.84

- (1) For 345 kv AC line, Bechtel values divided by 9.6×10^{12} Btus, for 500 kv AC line, values were divided by 20.8×10^{12} Btus. Values were then rounded to three significant figures.

Source: Bechtel Corporation, 1978. Energy Supply Planning Model, San Francisco, California.

TABLE 9-5

COST OF TRANSMISSION LINES
(Per 10^{12} Btus Produced)

COSTS	345 kv AC LINE DOLLARS (1978)	500 kv AC LINE DOLLARS (1978)
Construction (2 years)		
labor		
non-manual technical labor	850,000	614,000
non-manual non-technical labor	168,000	121,000
manual labor	4,320,000	2,690,000
materials		
primary non-ferrous metals	1,560,000	1,820,000
fabricated structural products	2,920,000	1,600,000
other materials	538,000	405,000
equipment	1,100,000	621,000
other construction costs	4,600,000	3,000,000
Total	16,100,000	11,500,000
Operation and Maintenance		
operation	none	none
maintenance		
labor	16,800	13,700
material	4,480	3,030
equipment	833	1,200
Total	22,100	17,930

Source: Bechtel Corporation, 1978. Energy Supply Planning Model,
San Francisco, California.

TABLE 9-6

LABOR FORCE FOR TRANSMISSION LINES
(Per 10^{12} Btus Produced)

PERSONNEL	345 kv AC LINE WORKERS PER YEAR		500 kv AC LINE WORKERS PER YEAR	
	First Year	Second Year	First Year	Second Year
Construction (2 years)				
non-manual technical labor				
civil engineers	3.9	2.6	2.8	1.9
electrical engineers	7.7	5.1	5.6	3.7
mechanical engineers	1.3	0.83	1.0	0.67
designers and draftsmen	5.3	3.5	3.8	2.5
supervisors and managers	1.0	0.63	0.65	0.43
non-manual non-technical labor	4.2	4.2	3.0	3.0
manual labor				
iron workers	16.6	49.7	9.2	27.6
electricians	0	0	1.1	3.4
linemen	13.1	39.4	8.1	24.1
truck drivers	2.7	8.0	1.7	5.2
Operation and Maintenance				
operation	none	none	none	none
maintenance	0.75	0.75	0.61	0.61

Source: Bechtel Corporation, 1978. Energy Supply Planning Model, San Francisco, California.

Operating costs and operating personnel requirements are zero. Annual maintenance cost and personnel data were provided by Bechtel. These figures were put on a 10^{12} Btus output basis by dividing by the annual energy output.

9.6 References

- Bechtel Corporation, 1978. Energy Supply and Planning Model. San Francisco, California.
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10.0 COAL TRANSPORTATION

The modes of coal transportation examined include unit trains, conventional (mixed-freight) trains, coal slurry pipelines, barges, and trucks. Conventional and unit trains operations are described in terms of the transport of typical eastern and western coals (see Chapters 2.0 and 3.0). Barge transportation of coal also assumes both eastern and western coal are carried. Due to the relative distances involved, only eastern coal is projected to be economically transportable in large quantities by truck. Slurry pipelines are assumed to use water as the transport medium.

Direct comparisons of coal transportation systems on a per-trillion Btus throughput basis are difficult. This is due to the fact that the measures compared on such a basis do not incorporate concepts of time, distance, or speed.

10.1 Conventional Trains

Conventional trains typically transport many commodities simultaneously, one of which may be coal. A number of data sources were evaluated in an attempt to quantify the parameters that define a conventional train. Table 10-1 presents estimates of the range of values for such parameters and the value chosen for this study as being representative. The representative values presented in Table 10-1, when combined with environmental loading factors,* provide estimates of environmental residuals resulting from coal transportation via conventional train. The costs, materials, transportation

*These factors represent changes in an environmental residual normalized in the mathematical sense on an appropriate basis such as million ton-miles or trillion Btus.

TABLE 10-1
CONVENTIONAL (MIXED FREIGHT) TRAINS

	RANGE	ASSUMED FOR ANALYSIS
Tons of freight per train	2029(1) to 7225(6)	7225
Average number of cars per train	67(1) to 85(6)	85
Coal car loadings as % of all non-unit train car loadings	13.5(1) to 20%(6)	20%
Average tons of coal loaded per car	85(6)	85
Average number of coal cars per conventional train	9(3) to 17(6)	17
Average number of trips per year for conventional trains	12(5) to 25(2)	20
Average one way haul distance per trip for conventional trains	300(6) to 600(4)	300
Average number and horsepower of locomotives per train	2(1) to 3(1) 2400(1) to 3000(6)	3 3000

Note: Numbers in parentheses, (), refer to the data sources listed on the following page.

SOURCES TO TABLE 10-1

- (1) Association of American Railroads, 1979. Yearbook of Railroad Facts. Washington, D.C.
- (2) U.S. Department of Energy, 1978a. Moving a National Resource - A Compendium on Interregional Coal Transportation. TID-28762 Interregional Coal Transportation Task Force. Lakewood, Colorado.
- (3) U.S. Department of Energy, Energy Information Administration, 1978b. Coal-Bituminous and Lignite in 1976. DOE/EIA-0118/1(76).
- (4) Oak Ridge National Laboratory, 1979. Energy Intensity and Related Parameters of Selected Transportation Modes: Freight Movements. ORNL-5554, Prepared for Data Analysis Branch, Transportation Program, Office of Conservation and Solar Applications, U.S. Department of Energy, Washington, D.C.
- (5) Data Resources, Inc., 1979. Transportation Review Summary, 1979-Modal Traffic and Equipment Forecasts - The Future of Coal and the Implications for Transportation. Lexington, Massachusetts.
- (6) Bechtel Corporation, 1975. Energy Supply Planning Model. Volume I. Revised 1978. San Francisco, California.

10.1.1.1 Residuals

Particulate emissions are produced during loading, while in transit, and during unloading of uncovered coal cars. Estimates of emissions during loading and unloading operation are based upon an emission factor of 0.4 pounds per ton loaded or unloaded (PEDCo, 1978). This estimate assumes uncontrolled facilities; it is potentially reducible to an average of 0.2 lbs per ton if 100 percent control is employed at one half of all loading and unloading sites.

The quantity of coal particulates lost in transit will vary depending on the rail route. The amount lost is also a function of train speed, type of coal, windspeed, condition of rolling stock, moisture content, and initial quantity of fines. A majority of particulates lost to windage (i.e., in transit) occurs during the early part of the trip. Estimates of quantity losses range between zero and one percent of total coal shipped; however, one estimate is as high as five percent under certain conditions (PEDCo, 1978).

A total of 442 pounds of coal per 85-ton car is lost based on an estimated 0.25 percent loss while in transit and a total of 0.2 pounds per ton lost during loading and unloading.* This is equivalent to 101.2 tons of particulates per trillion Btus of eastern coal or 137.6 tons of particulates per trillion Btus of western coal shipped.

Air pollutants from diesel-powered conventional trains include particulates, sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, and aldehydes. Particulates account for most of the air pollutants emitted by mixed trains. (The loss of fine particulates

* $(85 \times 2000 \times .0025) + 0.2 (85) = 442 \text{ lbs. per } 85 \text{ ton carload.}$

energy consumption, and environmental loading factors (or residuals coefficients) for conventional trains are based upon an assumed energy content of 12,850 Btus/pound for eastern coal and 9,450 Btus/pound for western coal. Due to the difference in heating value of the two coals, more coal and hence more coal transportation facilities are required to move one trillion Btu's of western coal than eastern coal. In turn, the environmental residuals produced are proportionally greater for western coal due to the greater tonnage of western coal moved per trillion Btus.

The mixed train in the Bechtel (1975) data base carries 7,225 tons of freight per trip. Eighty-five cars were assumed, each carrying 85 tons of freight. Further assuming that 20 percent of freight tonnage in mixed trains was coal (Hittman, 1974) one conventional train carries 1,445 tons of coal per trip, with 17 of the 85 cars being used for coal transportation. The Bechtel mixed train makes 20 round trips per year, averaging 300 miles one way.

Operation of any rail system, including one to carry coal, has the potential to produce undesirable pollutant emissions, noise, and aesthetic impacts. As discussed below, a significant problem associated with transportation of coal by either unit train or conventional train is the production of large amounts of particulates (PEDCo, 1978).

In 1977, 99 percent of all rail ton-miles were due to operations by trains with diesel-powered locomotives. The remaining one percent was due to electrically powered trains. The mixed train is assumed to use three diesel-powered locomotives (IR&T, 1978).

by blowing from the top of coal cars may possibly put out more fine solid materials than the remainder of the coal cycle (MITRE, 1977). Table 10-2 presents estimates of other pollutants produced by conventional trains.

Using 1969-1970 data, Hittman (1974) estimated three occupational safety coefficients for coal trains. In calculating these coefficients, no distinction was made between unit trains and mixed coal trains; aggregated accident data were provided for the rail industry as a whole. The coefficients are 0.061 deaths per 10^{12} Btus of coal input, 0.585 injuries per 10^{12} Btus of coal input, and 59.5 workdays lost per 10^{12} Btus of coal input. These coefficients pertain only to rail workers.

With regard to noise, ambient levels have been recorded inside diesel locomotives as high as 112 decibels (dBA). Noise levels as high as 95 dBA have been observed one hundred feet from a moving train, while at 1,000 feet the noise level may be about 75 dBA. Locomotive whistle noise at 1,000 feet from a train has been recorded at 85 dBA, dropping below 70 dBA at 1,300 feet. By comparison, Federal design noise levels range from 55 dBA for the interiors of dwelling units to 70 dBA for low-priority developed property. Table 10-3 presents design noise levels by land use category.

The amount of noise generated is affected by train speed, the number of cars in a train, track condition, and topography. Welding of tracks helps reduce noise, and man-made barriers can obstruct or dissipate sound emissions.

10.1.2 Economic Data

Bechtel (1975) was used to provide conventional train engineering cost estimates. A number of calculations and assumptions were

TABLE 10-2

AIR POLLUTANTS EMITTED DURING TRANSPORT
OF COAL BY CONVENTIONAL TRAIN

POLLUTANT	TONS PER 10 ¹² BTUS OF COAL DELIVERED	
	Eastern Coal	Western Coal
Particulates		
from coal loss (windage)	101.0	137.4
from diesel engines	<u>0.7</u>	<u>1.0</u>
Total	101.7	138.4
SOx as SO ₂	2.6	3.5
NOx as NO ₂	2.9	4.0
Hydrocarbons	2.0	2.7
CO	2.7	3.7
Aldehydes	0.5	0.6

Note: Gross emissions are equal to net emissions for conventional trains.

Source: U.S. Environmental Protection Agency, 1977. Compilation of Air Pollution Emission Factors (AP-42). 3rd edition, 9th supplement. Research Triangle Park, North Carolina.

PEDCo Environmental, Inc., 1978. Environmental Assessment of Coal Transportation. NTIS PB-285-936. Prepared for U.S. EPA, Industrial Environmental Research Laboratory, Cincinnati, Ohio.

TABLE 10-3

DESIGN NOISE LEVELS AND LAND USE RELATIONSHIPS

DESIGN NOISE Level-L10	DESCRIPTION OF LAND USE CATEGORY
60 dBA (exterior)	Tracts of lands in which serenity and quiet are of extraordinary significance and serve an important public need, and where the preservation of those qualities is essential if the area is to continue to serve its intended purpose. Such areas could include amphitheaters, particular parks or portions of parks, or open spaces which are dedicated or recognized by appropriate local officials or activities requiring special qualities of serenity and quiet.
70 dBA (exterior)	Residences, motels, hotels, public meeting rooms, schools, churches, libraries, hospitals, picnic areas, recreation areas, playground, active sports areas, and parks.
75 dBA	Developed lands, properties, or activities not included in above categories.
55 dBA	Residences, motels, hotels, public meeting rooms, schools, churches, libraries, hospitals, and auditoriums.

Note: Design noise level not to be exceeded more than 10 percent of the time.

Source: U.S. Department of Transportation, 1972. Federal Highway Administration, Policy and Procedure Memorandum (PPM) 90-2.

necessary to convert these estimates to a per 10^{12} Btus output basis.

First, only 17 of the 85 freight cars in the conventional train carry coal; therefore, the Bechtel numbers must initially be factored by 17/85. When the train first starts moving, it is assumed to carry 1,445 tons of coal. If the coal being shipped has an energy content of 12,850 Btus per ton (eastern coal) or 9,450 Btus per pound (western coal), the mixed train is carrying 3.7×10^{10} Btus (eastern coal) or 2.73×10^{10} Btus (western coal), respectively, at the beginning of the trip.

At twenty round trips per year, the mixed train will deliver either 7.42 (eastern coal) or 5.46 (western coal) $\times 10^{11}$ Btus annually. The Bechtel estimates, after being multiplied by 17/85, must then be divided by .742 (eastern coal) or .546 (western coal) to derive materials and construction cost coefficients in terms of cost per 10^{12} Btus annual throughput for the two types of coal being transported.

The number of man-years, 14, needed to run a mixed train for one year was also provided by Bechtel. To put this figure on a per 10^{12} Btus output basis, the same procedure was used as the one employed above for operating and maintenance cost. As a result, the values of 5.32 man-years per 10^{12} Btus of western coal delivered and 3.91 man-years per 10^{12} Btus of eastern coal delivered were obtained.

The operating cost of auxiliary energy consumption (i.e., diesel fuel) was based on 1.86 (west) or 1.36 (east) $\times 10^{10}$ Btus of diesel fuel per 10^{12} Btus of western or eastern coal delivered. Assuming a 1978 real price of \$0.398 per gallon of diesel fuel and an energy

content of 139,000 Btus per gallon of diesel, the cost of diesel fuel to deliver 1×10^{12} Btus would be \$53,000 per 10^{12} Btus of western coal and \$39,000 per 10^{12} Btu of eastern coal.

Construction costs estimates for conventional trains are based on data derived from Bechtel (1975). Table 10-4 presents capital requirements to transport one trillion Btus of coal on an annual basis. Operating cost estimates (excluding diesel fuel) are also presented in the table.

Materials required for construction of conventional train equipment (excluding track and load/unload facilities) on a per trillion Btu basis are shown in Table 10-5. These estimates are also based upon data presented by Bechtel (1975).

10.2 Unit Train

10.2.1 Characteristics of Coal Unit Trains

Coal unit trains are freight trains whose only cargo is coal. Unit trains were first used in 1957, and the use of unit trains for coal transportation became common by the mid-1960s (Ferguson, 1975). By 1974, 22 percent of all coal movements and 33 percent of all coal train traffic were by unit train (Hittman, 1974).

Shipping coal by unit train instead of conventional rail has several advantages. Unit trains are not subject to standard railroad tie-ups such as classification yards and layover points, promoting better coordination between mine production and coal consumers. In defining a unit train, the Bechtel (1975) Energy Supply Planning Model data base was used as much as possible, since it is the most comprehensive of the relevant data sources available.

TABLE 10-4

CONSTRUCTION AND OPERATING COSTS OF A CONVENTIONAL TRAIN

COMPONENTS	DOLLARS (1978) PER 10 ¹² Btus OF COAL DELIVERED ANNUALLY	
	Eastern	Western
Construction Costs		
Electrical equipment	138,000	188,000
Miscellaneous equipment	1,136,000	1,545,000
Other construction expenses	<u>38,000</u>	<u>52,000</u>
Total	1,312,000	1,785,000
Operating costs*	854,000	1,116,000

*Excludes diesel fuel costs.

Source: Bechtel Corporation, 1975. Energy Supply Planning Model,
Volume I. Revised 1978. San Francisco, California.

TABLE 10-5

MATERIAL REQUIREMENTS FOR CONVENTIONAL TRAINS
(Tons per 10^{12} Btu Transported Annually)

MATERIAL	EASTERN COAL	WESTERN COAL
Aluminum	5.64	7.64
Brass and bronze	3.33	4.52
Chromium	0.40	0.54
Copper	9.76	13.27
Iron	NA	NA
Manganese	6.02	8.18
Nickel	0.09	0.12
Steel	844.0	1,147.0

Source: Bechtel Corporation, 1975. Energy Supply Planning Model.
Volume 1. Revised 1978. San Francisco, California.

Bechtel's assumption of 10,500 tons of coal per unit train compares with 10,000 tons specified by Hittman (1974). The Bechtel train consists of 105 cars with each freight car carrying 100 tons of coal.

Hittman and Bechtel both include four diesel locomotives for each unit train. Hittman, however, assumes each locomotive has 2400 horsepower (HP), while Bechtel's locomotives are rated at 3000 HP. Other studies (PEDCo 1978, and U.S. Department of Energy, 1978a) indicate an average of five or more locomotives. Recently the trend for freight operation in general has been to rely on higher horsepower locomotives. Units of 3500 to 4000 horsepower are not unusual. Bechtel assumes each coal unit train trip is 700 miles one-way while PEDCo assumes an average distance of 306 miles. The unit train is assumed to be 99.75 percent efficient with 0.25 percent coal losses from unit trains occurring during loading, unloading, and in transit.* PEDCo estimates that approximately 0.4 lbs/ton is lost during uncontrolled loading and unloading. Since some loading facilities (silos) effectively confine particulate losses and spillages to zero, an average loss of factor of 0.2 lbs/ton has been assumed for all unit train loading and unloading operations. This is equivalent to total particulate emission controls at one-half of all load/unload facilities, and no controls at the remaining facilities. The percent of coal loss (windage) occurring during transit is associated with the trip length of the unit train; however, no data are available to allow estimation of windage losses on a per-mile basis for the entire length of a unit train trip. Most particulate losses are expected to occur within the first 500 miles of the trip from origin to destination. Windage losses of coal may be reduced significantly by wetting

*Windage losses were estimated to be 500 lbs. per carload (100 tons x 2000 lbs/ton x 0.0025).

the coal to be shipped, or by using covered gondola cars. The use of covered cars is impractical in terms of fast turnaround at loading and unloading points and wetting the coal during winter months could result in coal freezing to the cars and being difficult to unload.

Since most trains are diesel-powered, the unit train considered in this study is powered by diesel locomotives.

As with conventional trains, the cost, materials, auxiliary energy, and residuals coefficients for unit trains were based on an assumed energy content of 9,450 Btu's per pound of western coal shipped and 12,850 Btu's per pound of eastern coal shipped. When the coefficients are normalized to a per-trillion Btu basis, western unit trains have substantially greater requirements for materials and higher particulate emission levels because of the greater amount of western coal that has to be shipped to equal 1×10^{12} Btus.

10.2.2 Constraints

Coal unit train operations are regulated by the Interstate Commerce Commission (ICC). The ICC approves rail rates, routes, operating rights, abandonments, mergers, and related subjects. Actions by the ICC to establish coal freight rate guidelines will have major effects upon regions undergoing or slated to undergo coal resource development. This will be especially true in western coal regions where there are comparatively greater distances between origin and destination than in the east (Interstate Commerce Commission, 1979).

The problem of noise from unit trains is discussed in the residuals section of this report. Federal design noise standards are shown in Table 10-3 above.

10.2.3 Natural Resource Consumption

Approximately 1.30×10^{10} Btu's of diesel fuel are consumed by unit trains for every trillion Btus of western coal transported. This level of fuel consumption is predicated upon consumption of 350 Btus per net ton-mile. Eastern coal unit trains consume approximately 0.95×10^{10} Btus for every trillion Btus of coal transported.

10.2.4 Residuals

Particulates account for most of the air pollutants emitted by coal unit trains per trillion Btus of coal transported. Particulate emissions are produced during loading, in transit, and during unloading of uncovered coal cars. Estimates of emissions during loading and unloading are based upon an emission factor of 0.4 pounds per ton loaded or unloaded (PEDCo, 1978). This estimate is based upon uncontrolled facilities, and potentially is reducible to 0.2 lbs per tons if 100 percent control is assumed at one half of all loading and unloading sites.

The quantity of particulates lost during transportation will vary from region to region. The amount lost is a function of train speed, type of coal, windspeed, condition of rolling stock, moisture, and initial quantity of fines. Estimates of quantity losses range between zero and one percent of total coal shipped, however, one estimate is as high as five percent under certain conditions (PEDCo, 1978).

An estimated 520 pounds of coal per 100 ton car is lost per trip based on the assumption of an estimated 0.25 percent loss while in transit and a total of 0.2 pounds per ton lost during loading and unloading. Also included in the estimate of fugitive emissions are

particulates from combustion of diesel fuel occurring at a rate of 25 pounds per 1000 gallons of diesel fuel consumed. In total, this is equivalent to 102.9 tons of particulates per trillion Btus of eastern coal or 139.5 tons of particulates per trillion Btus of western coal shipped by unit train.

Other air pollutants produced by unit trains on a per trillion Btu basis are presented in Table 10-6. These pollutants occur primarily as a result of diesel engine operation.

Using 1969-1970 data, Hittman (1974) estimated three occupational safety coefficients for coal trains. Unit trains and mixed coal trains were not separated; aggregated accident data were presented for the rail industry. The Hittman coefficients are 0.061 deaths per 10^{12} Btus of coal transported, 0.585 injuries per 10^{12} Btus of coal transported, and 59.5 workdays lost per 10^{12} Btus of coal transported. These coefficients pertain only to rail workers.

Noise is one of the major environmental residuals associated with unit train operations. Noise levels inside diesel locomotives have been recorded as high as 112 decibels dBA. One hundred feet from a moving train, noise levels as high as 95 dBA have been observed, while at 1,000 feet, the noise level may be about 75 dBA. Locomotive whistle noise at 1,000 feet from a train has been recorded at 85 dBA, dropping below 70 dBA at 1,300 feet. By comparison, federal design noise levels range from 5 dBA for the interiors of dwelling units to 70 dBA for low priority developed property.

The amount of noise generated is affected by train speed, the number of cars in a train, track condition, and topography. Welding of tracks helps reduce noise, and man-made barriers can obstruct or dissipate sound emissions.

TABLE 10-6
UNIT TRAIN RESIDUALS

CATEGORY	TONS OF RESIDUAL PRODUCED PER 10 ¹² Btu ANNUAL THROUGHPUT	
	Eastern Coal	Western Coal
Particulates		
windage losses (at 0.25%)	101.4	137.5
diesel emissions (at 25 lbs/1000 gal. consumed)	<u>1.59</u>	<u>2.01</u>
Total	102.9	139.5
SO ₂	3.7	5.0
NO _x	3.2	4.4
Hydrocarbons	2.5	3.6
CO	3.4	4.6
Aldehydes	0.6	0.8

10.2.5 Material Requirements and Economic Data

The engineering cost and materials requirements for building one unit train are projected by Bechtel (1975). The cost coefficients are presented on a 10^{12} Btu basis. When loaded, a unit train carries 10,500 tons of coal which is equivalent to 0.198×10^{12} Btu of western coal or $.2698 \times 10^{12}$ Btu of eastern coal. Thus, 90 round trips per year represent the transport of approximately 17.82×10^{12} Btus of western coal or 24.29×10^{12} Btus of eastern coal. (The Bechtel numbers were divided by 17.82 for western unit train requirements and 24.29 for eastern unit train requirements in order to normalize costs on a per trillion Btu basis.) The construction and operating and maintenance costs are tabulated in Table 10-7. The materials used to construct the train are indicated in Table 10-8. According to Bechtel, a coal unit train can be manufactured in one year. None of the data sources reviewed indicated the number of workers needed to build a unit train. Table 10-8 presents unit trains material requirements expressed on a 10^{12} Btu basis.

Bechtel specifies that it costs \$6,221,000 (1978 dollars) to operate and maintain one unit train for one year (excluding the cost of diesel fuel) given the parameters noted above and the assumption that the train makes 90 round trips per year. Therefore, the operation and maintenance (O&M) cost per 10^{12} Btus of western coal delivered is \$351,000, and for eastern coal O&M costs per 10^{12} Btus are approximately \$258,000.

An estimate of the number of man-years needed to run a unit train for one year (167) was provided by Bechtel. The same procedure was used to put this figure on a per 10^{12} Btus output basis as was previously described for O&M costs. On this basis, approximately

TABLE 10-7

UNIT TRAIN CONSTRUCTION AND OPERATION COSTS

	DOLLARS PER 10 ¹² Btu	
	Eastern Coal	Western Coal
Construction		
Electrical Equipment	50,000	68,000
Miscellaneous Equipment	274,000	372,000
Other Constructor Expenses	<u>9,000</u>	<u>13,000</u>
Total	334,000	453,000
Operation and Maintenance Costs		
Diesel Fuel	39,000	53,000
Other	<u>258,000</u>	<u>351,000</u>
Total	297,000	404,000

TABLE 10-8
UNIT TRAIN MATERIAL REQUIREMENTS

MATERIAL REQUIRED	QUANTITY REQUIRED (tons per 10^{12} Btu)	
	Eastern Coal	Western Coal
Aluminum	1.87	2.54
Brass and Bronze (castings)	0.75	1.02
Chromium	0.10	0.13
Copper	2.58	3.51
Iron	NA	NA
Manganese	1.33	1.80
Nickel	0.02	0.03
Steel	185.00	251.33

Source: Bechtel Corporation, 1975. Energy Supply Planning Model, Volume I. Revised, 1978. San Francisco, California.

7.02 man-years are required to transport 10^{12} Btu of western coal and approximately 5.16 man-years are required to transport 10^{12} Btu of eastern coal.

10.3 Barge

10.3.1 Characteristics of Coal Barges

Coal barges are used to transport coal on navigable rivers and waterways of the United States. In 1976, 10.2 percent of all coal movements were by waterborne means (U.S. Department of Energy, 1978b).

In defining a standard barge tow, the Bechtel Energy Supply Planning Model (1975) data base was used as much as possible, since it is the most comprehensive of the relevant data sources available. Bechtel's assumption of 21,000 tons of coal per barge shipment compares with 20,000 tons specified by PEDCo, Inc. (1978). The Bechtel barge tow consists of 15 barges, with each barge carrying 1400 tons of coal.

Bechtel assumes one 4200 horsepower diesel-powered towboat for each barge tow. Other studies (PEDCo, 1978 and U.S. Department of Energy, 1978a) support this assumption. Recently, the trend for barge transportation operations has been to rely on higher horsepower towboats. The Bechtel model assumes each barge trip is 456 miles one-way, while PEDCo assumes an average distance of 273 miles one-way. Windage losses of coal are assumed to be negligible. This assumption is based upon low transit speeds, small surface area of coal pile in each barge exposed to wind, and, for western coal, higher moisture levels.

As with trains, the cost, materials, auxiliary energy, and residuals coefficients for barges were based on an assumed energy content of 9,450 Btu's per pound of western coal shipped and 12,850 Btu's per pound of eastern coal shipped. When the coefficients are normalized to a per trillion Btu basis, western barge tows have greater requirements for materials and higher emission levels because of the greater physical quantities of western coal shipped over longer distances.

Eastern barges were assumed to make 116 trips per year, at an average speed of 9 mph (14.4 kph) over a 190 mile route. Based on a 21,000 ton capacity, each barge ton transports approximately 62.6×10^{12} Btu annually. Western barges are expected to travel a 400 mile route (one way) at 9 mph (14.4 kph) and, due to the greater distance and lower heat value of western coal, transport approximately 26.7×10^{12} Btu of coal annually.

10.3.2 Constraints

Coal barges have several physical constraints which singly or collectively may effectively limit overall use of this transport mode. Most specifically, weather, width and depth of navigation facilities and capacity constraints on lock and dam facilities tend to limit the effectiveness of coal transportation by barge. Further, because there are fewer loading and unloading facilities for barges relative to railroads, coal transportation by barge is less flexible in terms of coal flows from origins to destinations. Given the existence of facilities and unused system capacity, barge transportation of coal is highly economical and environmentally desirable.

10.3.3 Natural Resource Consumption

Approximately 1.30×10^{10} Btu's of diesel fuel are consumed by barges for every trillion Btus of western coal transported. This level of fuel consumption is predicated upon consumption of approximately 0.1 gallon of fuel per horsepower hour.

10.3.4 Residuals

Particulate emissions are produced by combustion of diesel fuel to transport coal. Estimates of emissions are based upon an emission factor of 33.5 pounds per 10^3 gallons of diesel fuel consumed (U.S. Environmental Protection Agency, 1977).

Other air pollutants produced by barges on a per-trillion Btu transported basis are presented in Table 10-9. These pollutants occur as a result of diesel engine operation. Nonquantified residuals include potential water quality degradation from diesel fuel spills and coal spillage.

Other potential problems associated with barge transportation of coal include potential shoreline erosion caused by towboat wake and waterways congestion due to increased traffic levels. These increased levels of traffic will also result in longer delays at locks and dams presently operating at or close to design capacity.

10.3.5 Material Requirements and Economic Data

The engineering cost and materials requirements for building one 21,000 barge tow and towboat are projected by Bechtel (1975). The cost coefficients are presented on a 10^{12} Btu basis. Based upon assumed transit speeds, distances, and capacity, each barge tow

TABLE 10-9
COAL BARGE RESIDUALS

CATEGORY	TONS OF RESIDUAL PRODUCED PER 10 ¹² BTU ANNUAL THROUGHPUT	
	Eastern Coal	Western Coal
Particulates	0.55	1.57
SO ₂	0.52	1.47
NO _x	7.71	22.03
Hydrocarbons	0.62	1.76
CO	1.68	4.79

Source: U.S. Environmental Protection Agency, 1977. Compilation of Air Pollution Emission Factors (AP-42), 3rd edition, 9th supplement. Research Triangle Park, North Carolina

handling western coal makes 67.2 trips per year and carries 0.397×10^{12} Btus per trip. Conversely, an eastern coal barge tow travels a shorter distance, carries higher heat value coal and makes approximately 116 trips per year with about 0.540×10^{12} Btus on each trip. The Bechtel coefficients were divided by 26.7 (west) and 62.6 (east) to obtain estimates on a 10^{12} Btu annual throughput basis. The construction and operating and maintenance costs are tabulated in Table 10-10. The materials used to construct the barges are indicated in Table 10-11. According to Bechtel, a coal barge tow can be manufactured in less than one year. None of the data sources reviewed indicated the number of workers needed to build such barges. Table 10-11 presents estimates of coal barge material requirements expressed on a 10^{12} Btu basis.

Bechtel specifies that it costs \$1,596,000 (1978 dollars) to operate and maintain one coal barge tow for one year. This excludes the cost of diesel fuel and is based upon the parameters noted above. Therefore, the operation and maintenance (O&M) cost per 10^{12} Btus of western coal delivered is \$60,000, and for eastern coal O&M costs per 10^{12} Btus are approximately \$25,000.

An estimate of the number of man-years needed to run a coal barge for one year (31.4) was provided by Bechtel. The same procedure was used to put this figure on a per 10^{12} Btus output basis as was previously described for O&M costs. On this basis, approximately 1.2 man-years are required to transport 10^{12} Btu of western coal and approximately 0.50 man-years are required to transport 10^{12} Btu of eastern coal.

TABLE 10-10

COAL BARGE CONSTRUCTION AND OPERATION COSTS

	1978 DOLLARS PER 10 ¹² BTU	
	Eastern Coal	Western Coal
<u>Construction</u>		
Capital Costs	\$100,000	\$200,000
<u>Operation and Maintenance Costs</u>		
Diesel Fuel ^(a)	13,000	38,000
Other	<u>25,000</u>	<u>60,000</u>
Total	\$ 38,000	\$ 98,000

(a) Based upon an average cost of \$0.398 per gallon of diesel fuel in June, 1978.

Source: Bechtel, Inc., 1975. Energy Supply Planning Model. Volume I. Revised 1978. San Francisco, California.

TABLE 10-11

COAL BARGE MATERIAL REQUIREMENTS

MATERIAL REQUIRED	QUANTITY REQUIRED (Tons per 10^{12} Btu of Annual Throughput)	
	Eastern Coal	Western Coal
Carbon Steel	60.2	141.3
Alloy Steel	0.7	1.6
Stainless Steel	<u>0.1</u>	<u>0.3</u>
Total Steel	61.0	143.2
Aluminum	0.60	1.30
Chromium	0.10	0.10
Copper	0.50	1.10
Cast Iron	0.01	0.02
Manganese	0.50	1.10

Source: Bechtel Corporation, 1975. Energy Supply Planning Model,
Volume I. Revised, 1978. San Francisco, California.

10.4 Truck

10.4.1 Characteristics of Coal Trucks

Coal is transported by truck for short distances (generally less than 100 miles) in the East and Midwest. In 1976, approximately 90 million tons or 13 percent, of all coal shipments were made via truck (U.S. Department of Energy, 1978b). Western coal transportation by truck is not considered economically due to the distances involved. Several studies were evaluated to determine representative values defining specific parameters of coal transportation by truck including speed, tonnage per load, and distance traveled. The Bechtel Corporation, Energy Supply Planning Model was selected for its breadth of coverage. Several elements of the PEDCo, Inc. Environmental Assessment of Coal Transportation (1978) were also incorporated in the analysis of residuals and resources required for coal transported by truck.

The economics of truck transportation are such that long hauls are not feasible. While trucking costs per mile decrease beyond 100 miles, (PEDCo, 1978), the time expended versus the quantity of coal transported results in a generally unacceptable level of investment. Conversely, for short distances, the high degree of flexibility of truck transportation of coal outweighs its higher initial per-mile transportation costs.

The average truck haul assumed for this analysis is a 60-mile round trip, with an average speed of 20 miles per hour. The truck operates 10 hours per day, 240 days per year. On this basis, each truck makes 800 round trips per year and travels a total of 48,000 miles per year. Based upon a heat value of 12,850 Btu/lb for eastern coal, one truck transports 20,000 tons annually or an equivalent

0.514×10^{12} Btus. To obtain normalized parameter estimates on a per trillion Btu of annual throughput basis, the Bechtel estimates were divided by 0.514.

Construction costs for a typical 25 ton (net) coal truck were taken from Bechtel (1975). The Bechtel model indicates a total construction cost of \$79,000 per truck in 1978 dollars. The coal truck is projected to have a life of seven years. Estimated construction costs are \$150,000 per 10^{12} Btu of annual throughput.

Annual operating costs are projected to be approximately \$190,000 per 10^{12} Btu of annual throughput. This figure does not include the costs of diesel fuel. Based upon a 1978 cost of \$0.40 per gallon, an expenditure of an additional \$9,000 dollars (22,700 gallons) would occur. Total operating costs per 10^{12} Btu of annual throughput would then equal \$199,000.

Materials required for the construction of coal transport trucks include carbon steel, cast iron, structural steel, and steel plate. Table 10-12 presents estimates of material requirements per 10^{12} Btu of annual energy throughput.

10.4.2 Constraints

The principal constraint to expanded use of trucks for transporting coal is the economic disincentive associated with long-hauls. By effectively limiting the economically feasible transport distance for coal to a 100 mile radius, the total market for coal transported by truck is also effectively limited.

TABLE 10-12

MATERIAL REQUIREMENTS FOR COAL TRANSPORT TRUCKS

ITEM	TONS PER 10 ¹² BTU ANNUAL THROUGHPUT
Carbon Steel	22.6
Cast Iron	0.6
Structural Steel	3.8
Steel Plate < 1.5" thick	3.2

Source: Bechtel Corporation, 1975. Energy Supply Planning Model.
Volume 1. Revised 1978. San Francisco, California.

Another constraint on further development of coal transportation by truck is the imposition of maximum load limits on each truckload. While trucks might be able to physically carry higher weights, excessive road damage would result. For this reason, a maximum of 25 tons per load is assumed.

10.4.3 Natural Resource Consumption

The principal natural resource consumed in truck transport of coal is diesel fuel. Based upon a composite fuel consumption factor of 4.25 miles per gallon (PEDCo, Inc. 1978), the transportation of 1×10^{12} Btus of coal would require the consumption of 3.12×10^{10} Btus of diesel fuel.

10.4.4 Residuals and Products

The principal residual occurring as a result of truck transport of coal is particulate matter. PEDCo, Inc. (1978) indicates a range of potential emission levels between negligible and 0.05 percent. An additional 0.04 percent of all coal transported is assumed to be lost in loading and unloading. Thus, particulate emissions are projected to be 0.09 percent of all coal loaded. On this basis, a total of 38,911 tons of coal are loaded and 38,946 tons (or 10^{12} Btu) are delivered.

Particulate emissions could be limited through the use of covered trucks, organic sealants or addition of water to limit coal dust losses. Table 10-13 presents estimates of particulate and other atmospheric residuals occurring from truck transportation of coal. Based upon an emission rate of 0.09 percent of coal loadings, a total of 35 tons would be released due to windage per 10^{12} Btu of annual throughput. The remaining 0.16 tons is released as a result of diesel fuel combustion. Other residuals are presented in Table 10-13.

TABLE 10-13

RESIDUALS FROM TRUCK TRANSPORT OF COAL

CATEGORY	TONS PER 10 ¹² BTU
Particulates	
windage losses (at 0.09% of coal loaded)	35.0
diesel fuel consumption	<u>0.16</u>
Total	35.16
NO _x (a)	1.91
SO _x	0.29
CO	3.02
Hydrocarbons	0.48
Organic Acids	0.03
Aldehydes	0.03

(a) Based on EPA emission standards for 1980 model year vehicles at 18.1 grams/mile.

Source: U.S. Environmental Protection Agency, 1977. Compilation of Air Pollution Emission Factors (AP-42), 3rd Edition, 9th Supplement, Research Triangle Park, North Carolina.

10.5 Coal Slurry Pipeline

10.5.1 Characteristics of Slurry Pipeline

Slurry pipelines carry pulverized coal that is suspended in a transport media of water or oil. Pipeline technology using water to move coal is more advanced than technology using oil to transport coal. The currently existing domestic slurry pipeline, the Black Mesa Pipeline in Arizona, uses water as its transport medium (PEDCo, 1978).

The first commercial coal slurry pipeline built in the United States was a 108-mile line, 10-inches in diameter from Cadiz, Ohio, to Eastlake, Ohio (near Cleveland). In 1963, the Cadiz pipeline was deactivated due to the development of unit trains which proved to be more economical at the time.

The major advantages of slurry pipelines for moving coal long distances are low operating costs and a large proportion of "inflation proof" capital costs. The major disadvantages include high capital costs and substantial water consumption.

The coal slurry pipeline described in this section is based largely on the Bechtel (1975) Energy Supply Planning Model. The Bechtel model pipeline was lengthened to approximate the length of the proposed Energy Transportation Systems, Inc. (ETSI) slurry pipeline between Wyoming and Arkansas. Bechtel's pipeline has a 38-inch diameter pipe with an annual capacity of 25 million tons of coal moving over a distance of 150 miles. The ETSI pipeline is projected to be 1,355 miles long. Accordingly, system parameters (fuel, pipeline, residuals, etc.) were calculated on the basis of scaling up Bechtel's estimates to approximate the ETSI system.

The ratio by volume of solids to water in a coal slurry pipeline ranges from 0.45 to 0.55 (PEDCo, 1978). It has been assumed that the hypothetical mix is 50/50 water and coal. Before coal can be moved by slurry pipeline, the run of mine coal must be processed to the proper size particle. In addition to the pipeline itself, pumping stations, slurry preparation facilities, dewatering facilities, and storage facilities are required.

For the data summary sheet, a 98 percent efficiency (Btus output divided by Btus input) was assumed. This figure was taken from the University of Oklahoma study (1975) and is identical to the efficiency specified by Hittman (1974). The two percent loss is due to slurry water remaining in the largely dewatered coal which results in a reduction in the heating value of the delivered coal (PEDCo, 1978).

The cost, materials, auxiliary energy, and residuals coefficients for slurry pipelines were based on an assumed energy content of 18.9×10^6 Btus per ton of coal transported. This energy content is representative of western subbituminous coal produced in the Western Northern Great Plains Region where three to five large slurry pipelines are presently proposed (Coal Mining and Processing, 1979).

10.5.2 Slurry Pipeline Constraints

The question of eminent domain has posed a legal obstacle for slurry pipeline development. Under current Federal law, railroads (which would compete with slurry pipelines) may refuse to grant permits allowing pipelines to pass under their tracks. As of 1979, the ETSI pipeline had won 65 of 66 eminent domain lawsuits (Mining Engineering, 1979). Accordingly, the question of eminent domain seems to be resolved in favor of the pipelines. The availability of

sufficient water supplies is a further constraint upon slurry pipelines development. Competition for limited supplies of water in some coal regions may effectively limit pipeline growth.

10.5.3 Natural Resource Consumption

Hittman (1974) indicates that 6.93×10^5 kWh of electricity are consumed for every trillion Btus of coal input. Assuming a 2 percent loss of coal energy in transit, this is equivalent to 7.07×10^5 kWh per trillion Btus of coal delivered. This figure is based upon 273 miles of 18-inch pipe (i.e., the Black Mesa line).^{*} It is assumed that the pumping energy requirements per ton-mile are similar for both the Hittman estimates and the proposed ETSI 1,355 mile slurry pipeline, PEDCo, Inc. estimates 576 Btu per ton-mile will be expended (PEDCo, 1978). This is equivalent to 0.169 kWh per ton mile. Using an estimated throughput of 25 million tons/year moved over a 1,355 mile distance, total energy consumption for slurry preparation, pumping and dewatering would be approximately 5.7×10^9 kWh. This is equivalent to 1.2×10^7 kWh per 10^{12} Btus moved from origin to destination.

As noted above, two percent of the energy content of coal being shipped is lost in the slurry pipeline. This implies that 20 million Btus of coal are lost for every trillion Btus of coal output. No assumption was made concerning the chemical composition of the coal shipped.

Land use was calculated on the basis of trillion Btus of annual capacity (coal transported). Facilities include the pipeline,

^{*}These same assumptions and calculations were also used to convert material requirements to a per 10^{12} Btus output basis.

associated right-of-way (ROW), pumping stations, slurry preparation facilities, and slurry dewatering facilities. Figures for right-of-way and terminal facilities were derived from Bechtel and scaled up to the length of the ETSI pipeline.

According to Hittman, the Black Mesa line has a 62.5 foot right-of-way and thus occupies 2,070 acres.* By contrast, the Bechtel line is assumed to have a 100 foot right-of-way. With an annual capacity of 472.5 trillion Btus of coal, a length of 1,355 miles, approximately 34.8 acres are used for rights of way (ROW) per trillion Btus input. With two percent coal losses, this is equivalent to 35.4 acres per net trillion Btus delivered.

The Black Mesa line has four pumping stations, each occupying about 50 acres, including the station house, access roadways, and storage ponds for water and emergency slurry dumps. Hittman (1974) calculates that this implies that 1.71 acres are used by pumping stations per trillion Btus input, which is equivalent to 1.74 acres per trillion Btus delivered. Accordingly, it is assumed that these relationships also holds for the ETSI line. Based on an average separation of 80 miles between pump stations, a total of 850 acres for 17 pumps stations would be required. This is equal to 1.79 acres per trillion Btu input or 1.83 acres per net trillion Btus delivered. In general, it should be noted that any acre per-Btu land use coefficient will vary for pipelines of different lengths, diameters, those traversing different terrain or having different solid-to-water ratios.

Finally, the amount of water consumed by slurry pipelines must be considered. The water used by slurry pipelines is "consumptive" in the sense that it is not returned to its origin. Rather, it may

*273 miles times 62.5 foot R.O.W. = 2,070 acres.

be discharged, after treatment, into local waterways at the dewatering site. Additionally, it may be used for power plant cooling prior to discharge. Some pipeline systems have been designed in which the slurry water is recycled, but no such system has ever been built. DOE's Annual Environmental Analysis Report (AEAR) cites a study by Radian Corporation which estimates water requirements at approximately the equivalent of 30.4 acre-feet per trillion Btus of coal transported (i.e. input) annually. On the basis of 52,910 tons of western coal per 10^{12} Btu input, and a 50/50 coal/water mix, the estimated water requirement for the ETSI pipeline are 38.8 acre feet per 10^{12} input.* The variation in the water use estimates is due to the variation in heat value for the input coal.

10.5.4 Residuals

Virtually no direct air pollution is caused by operating slurry pipelines. Potential spills of coal slurry represent a threat in the event of pipeline rupture. The water transport media may absorb some of the organic compounds present in coal such as phenols, etc. Potential water quality problems must be resolved prior to discharge.

Pipeline Cost Estimates

The Bechtel figures for the pipeline itself were multiplied by 9.03 to estimate costs and materials needed for 1,355 miles of pipeline.**

$$*1355 = 9.03$$

150

**One acre foot of water = 1,359.0 tons, accordingly 52,910 tons of water = 38.9 acre feet of water.

The second step in deriving materials coefficients was to add the figures for slurry preparation and dewatering facilities to the figures for 1,355 miles of pipeline. The final step was to divide these totals by 472.5 which represents the annual pipeline net capacity in trillions of Btus delivered. The results are shown in Table 10-14.

The construction costs (in 1978 dollars) are shown separately for three components of the system. The coefficients for the material requirements and pipeline construction cost were derived by multiplying the Bechtel data by 9.03. Estimated construction costs are shown in Table 10-15.

10.6 References

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TABLE 10-14
MATERIALS REQUIRED TO CONSTRUCT A COAL SLURRY PIPELINE

MATERIAL	TONS PER 10^{12} BTUS ANNUAL THROUGHPUT
Aluminum	1.3
Brass and bronze	0.4
Chromium	0.3
Concrete	3,016.9
Copper	4.4
Iron	NA
Manganese	9.6
Nickel	0.0
Steel	1,286.0

Note: Based on 1,355 miles of 38-inch diameter pipeline, preparation plant and dewatering plant.

Source: Bechtel Corporation, 1975. Energy Supply Planning Model.
Volume I. Revised 1978. San Francisco, California.

TABLE 10-15
COAL SLURRY PIPELINE COST ESTIMATES

MILLIONS OF 1978 DOLLARS (Per 10^{12} Btu (Net) Annual Throughput)	
Construction	
pipeline (1,355 miles)	2.10
preparation plant	0.38
dewatering plant	0.15
Total*	2.64
Operation and Maintenance	0.18

*Total cost divided by annual trillions of Btu (Net) throughput.

Source: Bechtel Corporation, 1975. Energy Supply Planning Model.
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