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ENERGY UTILIZATION AND ENVIRONMENTAL CONTROL TECHNOLOGIES IN THE COAL-ELECTRIC CYCLE

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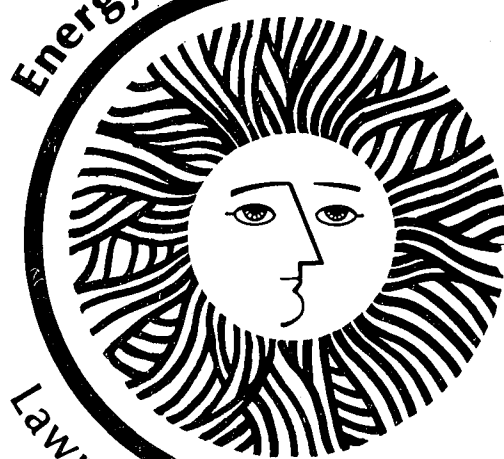
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Energy Utilization And Environmental
Control Technologies In
The Coal-Electric Cycle

George C. Ferrell

October 1977

Lawrence Berkeley Laboratory University of California/Berkeley

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CHAPTER 1

INTRODUCTION AND SUMMARY

1.1. THE ROLE OF COAL IN THE UNITED STATES

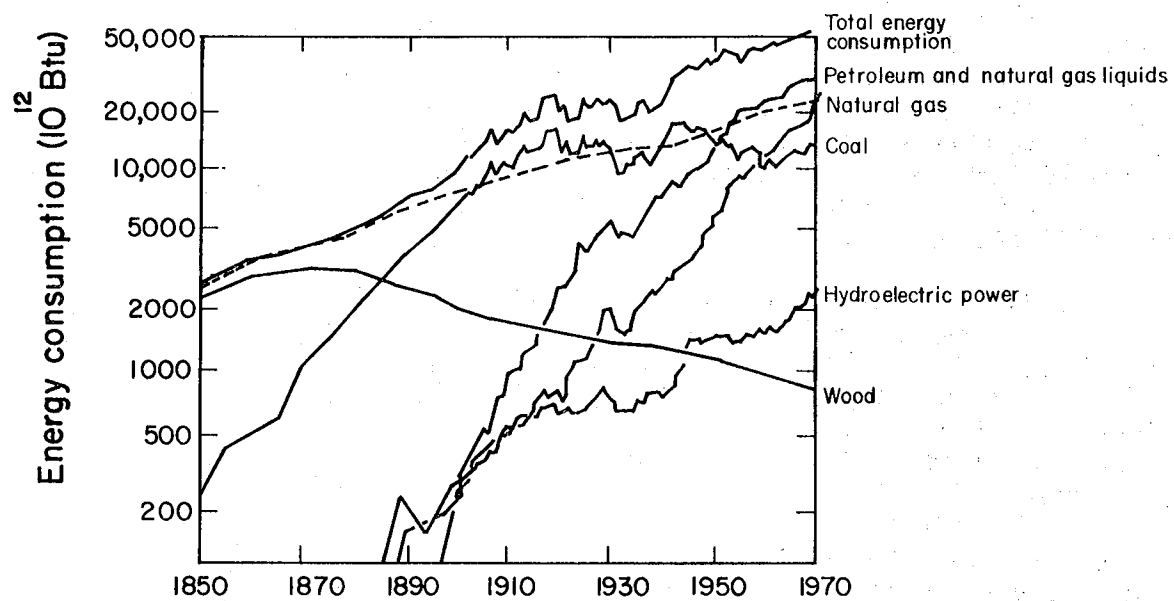
About eighty-five percent of United States fossil fuel resources are in the form of coal, currently some 3.2 trillion tons, which are located in large concentrated deposits in many parts of the country. Of this vast energy resource, some 430 billion tons are mineable using present technology, representing an energy reserve of about 10,000 quadrillion (10^{15}) Btus. Thus, the United States energy economy will undoubtedly be heavily dependent on the use of coal, at least for the next several decades, and if wisely managed, for the next several centuries. As natural gas resources diminish, as prices for petroleum increase, and with present political, economic and environmental uncertainties for nuclear energy, the use of coal to supply U. S. domestic energy needs, in an environmentally acceptable manner, has become increasingly necessary.

Historically, coal has been considered a keystone energy source, providing much of the energy to industrialize the American economy (1). Coal is now being called upon to again provide essential energy for the U.S., especially in the form of electric power, and perhaps in the form of synthetic fuels (2). Its direct industrial use to produce heat and steam, as well as its use for metallurgical purposes, has been historically significant and also has an important future. In both the short and long run coal may be viewed as a transition source of energy for the United States (3). The next several decades will likely reveal a transition toward increased uses of coal, while the development of long-term energy sources such as solar, geothermal and fusion will be accompanied by a transition away from coal.

Coal has been the backbone for the U. S. energy economy during the industrialization period of the 1800's (4). As shown in Figure 1-1, the history of major energy consumption for the U. S. reveals that coal essentially replaced wood as the predominant fuel before 1900. Coal has since been increasingly replaced by petroleum and natural gas. The market share for coal as a primary fuel reached its peak just after the turn of the century, when it was used in over 75 percent of the total U. S. energy consumption. Since that time coal has had a declining market share, as shown in Figure 1-2 (5).

Now coal is experiencing a revival. Coal production has begun to increase again and is currently planned to expand considerably. As shown in Tables 1-1 and 1-2, from a base of approximately 650 million tons per year in 1975, new mines and development and expansion of those mines is currently planned to add 670 million tons per year by 1985 (6). In addition, electric power production from coal is expected to increase significantly. Short-term estimates of planned capacity additions suggest that from a base of 176,000 MW of installed coal-fired generating capacity in 1974, planned additions for electricity from coal could be 126,000 MW during the 1975-1984 time period (7).

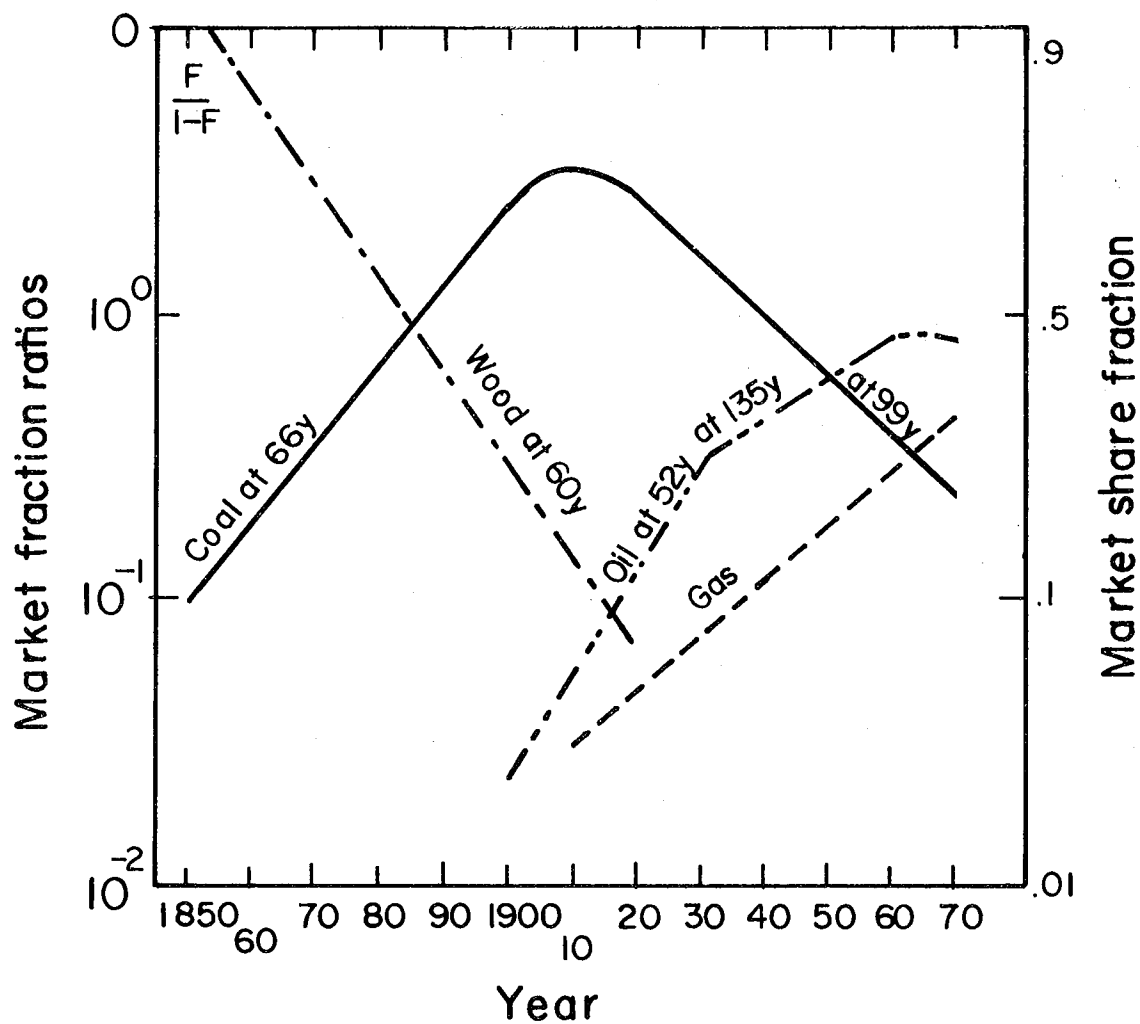
Figure 1-1
UNITED STATES ENERGY CONSUMPTION
(10^{12} Btu)



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Source: "An Agenda for Energy", by Hoyt J. Hottel and J.B. Howard
© Technology Review. Note: The dashed line is population
in units of 10^4 .

Figure 1-2
 MARKET SHARES OF PRIMARY ENERGY CONSUMPTION
 IN THE UNITED STATES



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Source: "On Strategies and Fate", by C. Marchetti, in Second Status Report of the IIASA Project on Energy Systems, W. Hafele, et al., © II ASA, 1976.

Table 1-1. United States Coal Production in 1975 and Estimated Production in 1976. (millions of tons/year)

Type	Underground Mining		Surface Mining		Total	
	1975	1976	1975	1976	1975	1976
Bituminous and Lignite	292.83	291.37	355.61	368.84	648.44	660.21
Anthracite	0.64	0.52	5.49	4.35	6.13	4.87
Total	293.47	291.89	361.10	373.19	654.57	665.08

Source: Coal Age, February, 1977.

Table 1-2. Planned United States Coal Production Capacity Additions
1976-1985, as of 1977 (millions of tons/year).

Year	Underground Mining	Surface Mining	Total
1976	33.41	20.34	53.75
1977	44.95	47.27	92.22
1978	41.76	54.15	95.91
1979	36.53	51.15	87.68
1980	27.67	94.18	121.85
1981	11.28	52.80	64.08
1982	10.69	40.50	51.19
1983	7.83	25.50	33.33
1984	6.77	23.20	29.97
1985	23.50	17.60	41.10
Total	244.39	426.69	671.08

Source: Coal Age, February, 1977.

Projected coal-fired electric generating capacity and utility coal demand by year are shown in Table 1-3. This suggests that the total coal-fired capacity and utility coal demand may increase by 60-70 percent over the next decade.

1.2. TECHNOLOGIES IN THE COAL-ELECTRIC CYCLE

This report presents an overview and assessment of the currently commercial and possible future technologies that are a part of the coal-electric cycle. From coal production to residual emissions control at the power plant stack, this report includes a brief history, current status and likely future assessment of each technology. It discusses the process operation, environmental emission characteristics, market constraints and uncertainties, for commercialization of these technologies. It also includes detailed cost estimates focusing primarily on coal preparation, coal-electric generation and emissions control systems. Shown in the coal-electric system in Figure 1-3, the technologies assessed in this report are those that are primarily designed to produce electric power from coal while controlling air pollution emissions. A list and a description of important parameters for each technology are given in Table 1-4.

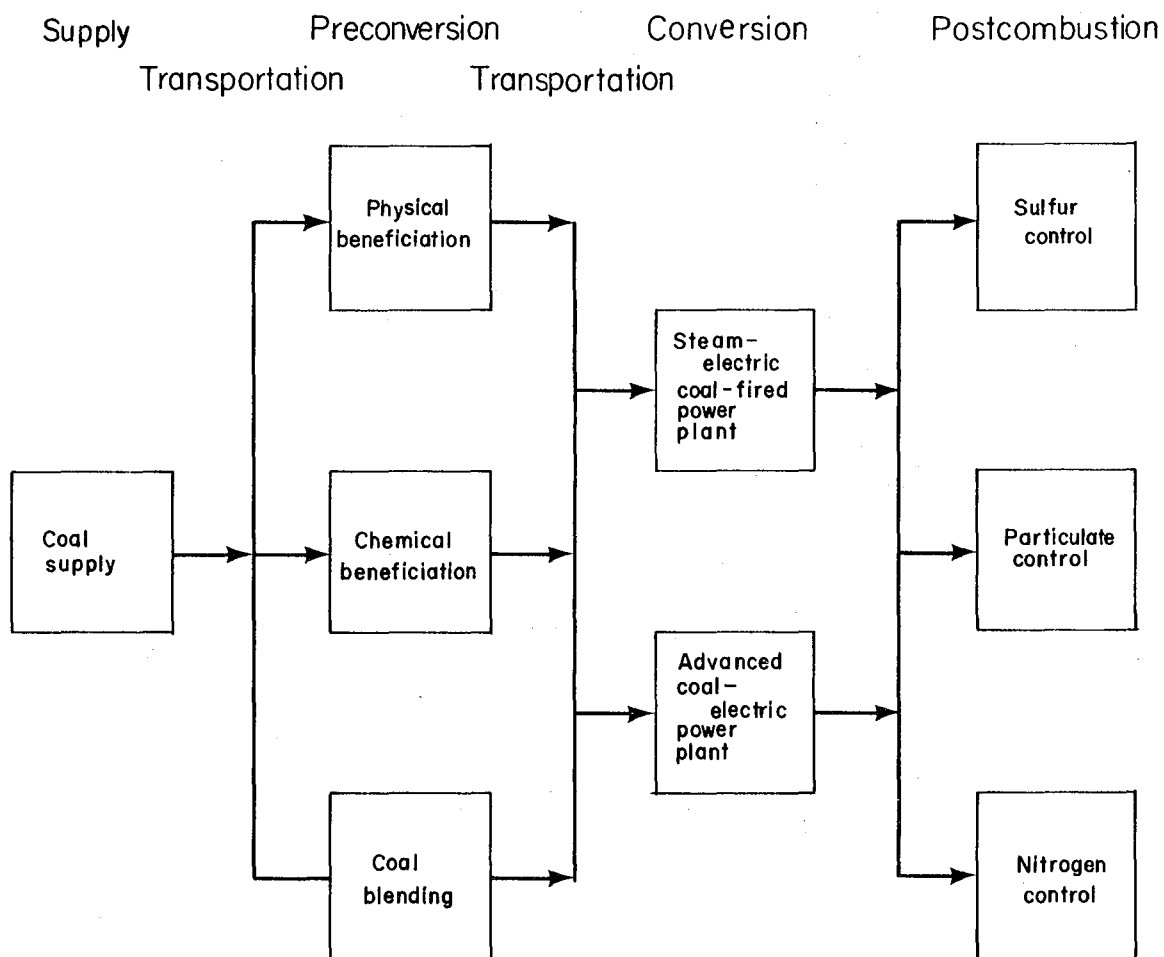
In order to provide electric power from coal while meeting environmental standards, many technological options are currently available in various stages of commercialization. Historically, the primary energy converter has been the conventional steam-electric power plant. Advanced technologies that convert coal to electric power are now rapidly becoming commercialized, including fluidized bed and combined-cycle gasification systems. Other technologies in the coal-electric cycle function to control or manage the residuals inherent in coal, which consist primarily of sulfur, ash and nitrogen related compounds. These residual-management technologies operate in the cycle in one of three general categories which include preconversion (e.g., coal preparation), conversion (e.g., combustion modification) and postconversion (e.g., flue gas desulfurization).

The primary function of the conventional energy converter in the coal-electric cycle is to extract heat from coal which is used to produce steam. The steam is expanded in a turbine which drives an alternator producing electricity. In conventional systems, the process does not exceed an average thermal efficiency of approximately 35 percent. Advanced systems are now being commercialized which include the use of both steam and gas turbines. These systems increase the thermal efficiency of the energy conversion process above 35 percent, with current commercial efficiencies as high as 38 to 40 percent. These advanced systems can also be operated on a much wider range of fuels, and can control residual emissions within the combustion process itself, unlike most conventional systems.

Other technologies in the coal-electric cycle are designed primarily for residual reduction or removal. These processes have technical limits of residual control, however, they may generally be operated at a variable level of residual removal which is accomplished at a variable cost. It is

Figure 1-3

TECHNOLOGIES IN THE COAL-ELECTRIC CYCLE



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Table 1-3. Projected Coal-Fired Power Plant Capacity and Utility Coal Demand 1975-1984.

Year	Net Coal-Fired Additions (10^3 MW)	Total Coal-Fired Capacity (10^3 MW)	Utility Coal Demand (10^6 t/y)
1975	10.6	186	452
1976	9.2	195	483
1977	12.6	208	519
1978	14.8	223	558
1979	18.2	241	605
1980	15.8	257	652
1981	12.5	269	686
1982	12.0	282	714
1983	12.0	294	746
1984	7.0	301	769

Source: Federal Energy Administration, Reference 7.

Table 1-4. Technologies and Associated Parameters in the Coal-Electric Cycle.

• COAL SUPPLY/PRODUCTION	• ADVANCED COAL-ELECTRIC GENERATION
resources/reserves	thermal efficiency (heat rate)
coal characteristics	operating conditions
energy content	capacity
sulfur	environmental emissions
ash	resource requirements
nitrogen	cost
resource requirements	
mining method	• STACK GAS DESULFURIZATION
environmental factors	
cost	sulfur removal
	particulate removal
• COAL TRANSPORTATION	capacity
mode	operating conditions
distance	energy requirements
quantity	resource requirements
resource requirements	cost
environmental factors	
cost	• PARTICULATE CONTROL METHODS
	particulate removal
• COAL BENEFICIATION	process technology
coal characteristics	mechanical
energy content	electrostatic precipitation
sulfur removal	fabric filtration
ash removal	capacity
nitrogen removal	operating conditions
waste products and emissions	resource requirements
process technology	cost
crushing	
washing	• NITROGEN CONTROL METHODS
blending	nitrogen removal
chemical methods	other residual removal
resource requirements	process technology
cost	combustion modification
	catalytic removal
• STEAM-ELECTRIC COAL-FIRED POWER PLANT	capacity
	operating conditions
thermal efficiency (heat rate)	resource requirements
operating conditions	cost
capacity	
environmental emissions	
resource requirements	
cost	

the nature of these technologies that a greater degree of control, i.e., higher removal efficiencies, is accomplished at an ever increasing expense, so that large costs are required to reduce emissions to low levels, and zero-level emissions are unattainable. It is also a characteristic of these technologies that although their primary function may be to reduce a single residual, or in some cases several residuals, their operation is such that the removal performance of other non-design residuals is often affected. The removal performance of these other residuals may either be enhanced or degraded. For example, the sulfur content of coal, and thus the sulfur content of the fly ash, influences the collection efficiency of particulate matter in an electrostatic precipitator. The use of low sulfur coal in a high-sulfur-designed electrostatic precipitator will likely increase the fly ash resistivity to levels that will cause reduced particulate collection efficiencies. Also, for example, flue gas scrubbers will remove both sulfur oxides and particulate matter from effluent stack gases, however, reliability and design load are generally decreased if high ash coals are burned.

In addition to influencing multiple residual removal performance, the operation of combustion and postcombustion control technologies may influence the performance of the primary energy converter, the coal-fired power plant. For example, nitrogen-oxides control by combustion modification may either reduce (water injection) or enhance (low-excess air) the thermal efficiency of a power plant. Also, for example, the power plant capacity or operating load factor may be reduced by the operation of a flue gas desulfurization system, which requires power for pumps, or by the operation of flue gas recycle nitrogen-oxides control system, which requires power for fans. Reductions in thermal efficiency are incurred at the expense of increased overall fuel costs, and reductions in power plant capacity may be accounted for in terms of increased capital-related charges, in accordance with a typical utility financing scheme. Lastly, it is the characteristic of a technology such as an electrostatic precipitator to have increased removal efficiencies at less than design loads, while removal efficiencies decrease at greater than design conditions, so that the operating condition of the power plant itself may influence residual removal performance.

1.3. REPORT SUMMARY

Subsequent chapters in this report develop in detail the characteristics for each technology described above. Chapter 2 discusses United States coal and coal production. Current and historic aspects of coal and coal production are reviewed, and coal resources and reserves are described including quantities and composition. Coal production is then discussed including production capacities, locations and cost estimates. Finally, a list of market constraints and uncertainties is developed and briefly outlined. A detailed description of U.S. coal characteristics, including a description of existing computerized data bases and computer programs that access the data have been surveyed and are published elsewhere (8)

Coal beneficiation is discussed in Chapter 3, including its historical background, some current trends for coal preparation technology, an overview view of the various processes that are available based on physical and

chemical methods, and a summary of cost estimates. Chapter 3 also includes a description of sulfur and ash reduction potentials of U. S. coals, environmental emission characteristics of coal preparation technologies and some constraints and uncertainties that face the coal preparation industry. A brief survey of coal preparation cost and operating models has been conducted and is published elsewhere (8).

A very brief discussion of coal transportation is contained in Chapter 4, including the modes of rail, waterway, truck and slurry pipeline. A summary of comparative cost estimates by mode is also included.

In Chapter 5, coal-electric generating technologies are discussed, including an assessment of the current status of the coal-fired power plant, a process description of conventional and advanced systems, environmental emissions and a summary of cost estimates for present and future technologies.

The most extensive chapter of this report describes emissions control technologies for conventional coal-fired power plants. Chapter 6 includes background information, performance data and summary cost estimates for technologies that control the three primary air pollutants (SO_x , particulates and NO_x) on a continuous basis. The emission control technologies discussed in this chapter include: flue gas desulfurization, particulate control by mechanical, electrostatic and filtration methods, and nitrogen oxides control by combustion modification and postcombustion control methods. Mathematical models for the cost and operation of flue gas desulfurization and particulate control technologies have been developed and are published elsewhere (8).

The coal-electric cycle involves an extensive and complicated network of technologies. This report is a state-of-the-art review and assessment of the currently commercial and possible future technologies in the United States that are a part of the coal-electric cycle. Such a review and assessment is a prerequisite for environmental policy analysis.

CHAPTER 1

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CHAPTER 2

UNITED STATES COAL AND COAL PRODUCTION

Approximately 85 percent of the United States fossil-fuel resources are in the form of coal. The effective utilization of this large energy resource depends on many complex factors including geographic location, mining method, capital, manpower and materials availabilities, transportation options, environmental regulations and prices of substitutable fuels.

In this chapter current and historic aspects of U.S. coal and coal production are briefly discussed. Estimated coal resources and reserves are described including quantities and composition. Coal production is then discussed including production capabilities, location, costs and prices. Finally, a list of constraints and uncertainties that influence coal production and utilization is developed and briefly outlined.

2.1. COAL RESOURCES AND RESERVES

The United States has vast resources of coal. The U.S. Geological Survey has recently identified a coal resource of some 1,600 billion tons, with a postulated additional 1,600 billion tons yet to be identified (1). Of this total resource, about 430 billion tons may be in deposits of a type which are economically feasible to mine (2). Approximately 300 billion tons could be mined by underground methods, while the rest is amenable to surface mining as shown in Table 2-1. Data on the reserve base of U.S. coals is rather extensive (3-5), including computer data banks (6,7).

The heating value of coals is important in assessing coal resources and reserves. Typical energy contents of coal range from about 7,000 for lignite to over 14,000 Btu/lb for anthracite. The reserves of lignite on a weight basis comprise about 6.5 percent of the total, but could provide only 3.8 percent of the total energy.

About 46 percent of U.S. coal contains one percent or less sulfur by weight (8). Twenty-one percent ranges between one and three percent sulfur, and an additional 21 percent of U.S. coal reserves have a sulfur content of greater than three percent. The sulfur content of 12 percent of the coal resource is unknown. Eighty-four percent of the coal reserves with less than one percent sulfur have been identified to be located west of the Mississippi River.

Not all of the demonstrated (9) reserve base is available for use. Only 50-60 percent of the coal may be recovered in an underground mine using room and pillar methods, while 90 percent may be recovered in some surface mines. Only approximately 10 percent of the total U.S. coal resources lie within 150 ft of the surface, which is near the current economic and technical stripping depth. This limits the wide spread use of surface mining techniques, even in the Western States, where about 43 percent of the demonstrated coal reserves are surface mineable (10). New open-pit mine technology may allow

Table 2-1. Coal Reserves of the United States, 1974 (Billion Tons).

Coal Rank	Underground	Surface	Total	Energy Value (Quads)
Bituminous	192	41	233	6,100
Subbituminous	98	67	165	2,800
Lignite	0	28	28	400
Anthracite	7	--	7	200
Total	297	137	434	9,500

Source: U.S. Geological Survey, Reference 2.

mining to depths of approximately 500 M (about 1600 ft) with overburden to-coal ratios of more than 6 to 1 (11).

2.2. COAL PRODUCTION AND ECONOMICS

Around the 1900's coal supplied almost 90 percent of U. S. energy demands. By 1950 coal was supplying less than 40 percent, while by 1972 this fraction was less than 20 percent (12). Total current coal production however has been increasing, since 1960 and is projected to double within the next 10 to 15 years (13). Some western mines have more than doubled their output over the last 10 years. The rate of U. S. coal development is dependent on many complex constraints as outlined in this section below. These constraints influence both coal production capacities and coal prices.

Coal Production Capacities

In 1973 some 600 million tons per year of coal were being mined in the United States. This is a 14 percent increase over production in 1965 as shown in Table 2-2. The majority of this increase has occurred in the western coal fields using surface mining methods; total underground mining has decreased. New mine openings between 1973 and 1983 may add an additional 240 million tons per year as shown in Table 2-3 (15). Additional mining capacity will probably exceed current forecasts except where constrained as discussed below. Statistics on coal production, distribution and utilization are compiled by the Bureau of Mines on a periodic basis (16).

Coal Cost and Price

The Bureau of Mines has developed cost estimates for coal mining (17-19). A summary of these estimates is shown in Tables 2-4 through 2-7.

Their basic approach was to develop costs as a function of mine size and seam thickness using the cost accounting method of discounted cash flow. These studies have been recently reviewed including a review of other economic studies of coal supply (20,21). The Bureau of Mines work is used extensively by others (22-27).

The Federal Energy Administration's Coal Task Force developed cost estimates for coal mining in preparing its Project Independence Blueprint (12). A summary of selected data is shown in Tables 2-8 through 2-10. These data appear to be slightly higher than the Bureau of Mines cost estimates, although they are likely within the accuracy represented by such estimates. The FEA estimates were made in 1974 dollars.

Table 2-2. Comparison of Coal Production by Mine Type and Supply Region 1965-1973 (Million Tons Per Year).

FEA Coal Supply Region*	<u>Underground</u>		<u>Surface</u>		<u>Total</u>		% change
	1965	1973	1965	1973	1965	1973	
1	121	99	79	78	191	177	-7%
2	166	135	29	79	195	205	+5%
3	42	56	79	94	121	150	+24%
4	-	-	-	7	-	7	--
5	-	-	6	32	6	32	+433%
6	9	10	4	14	13	24	+85%
7	-	-	1	4	1	4	+300%
Total	338	300	189	299	527	599	+14%

Source: Bureau of Mines, in Reference 12, p. 9.

* The FEA coal supply regions correspond approximately with the U.S. Bureau of Mines Provinces, except regions 5 and 6. Region 5 includes the Northern Great Plains and part of the Rocky Mountain Provinces.

Table 2-3. New Coal Mine Capacity by Year and Mining Method, 1973-1983, as of 1975 (million tons per year).

Year	Underground	Surface	Auger	Total
1973	4.1	9.6	0.2	13.9
1974	15.9	7.1	-	23.0
1975	10.7	4.5	-	15.2
1976	13.3	11.8	-	25.1
1977	21.4	2.8	-	24.2
1978	11.0	2.5	-	13.5
1979	9.1	20.5	-	29.6
1980	4.0	34.0	-	38.0
1981	5.0	--	-	5.0
1982	--	14.0	-	14.0
1983	--	35.0	-	35.0
Total	94.5	141.8	0.2	236.5

Source: Keystone Coal Industry Manual, 1975, in Reference 15.

Table 2-4. Cost Analyses for Coal Strip Mines--1972 (late \$1969).

Production (Million Tons Per Year)	Capital Cost		Operating Cost		Selling Price 12% DCF	
	\$10 ⁶	\$10 ⁶ /yr	\$/ton	¢/10 ⁶ Btu	\$/ton	¢/10 ⁶ Btu
BITUMINOUS COAL: EASTERN PROVINCE						
1	12.73	4.15	4.15	15.7	5.40	20.5
3	28.00	9.17	3.06	11.6	4.01	15.2
BITUMINOUS COAL: INTERIOR PROVINCE						
1	13.71	3.90	3.90	16.3	5.35	22.3
3	24.87	7.75	2.58	10.8	3.46	14.4
SUBBITUMINOUS COAL: ROCKY MOUNTAIN AND NORTHERN GREAT PLAINS						
1	7.90	3.03	3.03	14.3	3.83	18.1
5	28.66	12.03	2.40	11.4	3.03	14.3
5	13.88	6.94	1.39	8.2	1.64	9.6
LIGNITE: NORTHERN GREAT PLAINS						
1	6.38	2.37	2.37	16.5	3.01	20.9
5	20.75	8.38	1.68	11.7	2.12	14.7

Source: Bureau of Mines, Reference 17.

Table 2-5. Cost Analysis for Coal Strip Mines--1974 (Early \$1974).

Production (Million Tons Per Year)	Province	Capital Cost (\$10 ⁶)	Operating Cost (\$/Ton)	Selling Price 12% DCF (\$/Ton)
4.80	Eastern	61.07	3.65	4.79
6.72	Interior	76.75	3.25	4.23
9.20	Northern Great Plains	56.29	2.27	2.66

Source: Bureau of Mines, Reference 19.

Table 2-6. Cost Analysis for Coal Underground Mines in 48-Inch Seams--1974 (Late \$1973).

Production (Million Tons Per Year)	Capital Cost (\$10 ⁶)	Operating Cost (\$/Ton)	Selling Price 12% DCF (\$/Ton)
1.03	21.61	7.60	9.11
2.06	36.26	6.97	8.27
3.09	51.98	6.81	8.06

Source: Bureau of Mines, Reference 18.

Table 2-7. Cost Analysis for Coal Underground Mines in 72-Inch Seams--1974 (Late \$1973).

Production (Million Tons Per Year)	Capital Cost (\$10 ⁶)	Operating Cost (\$/ton)	Selling Price 12% DCF (\$/ton)
1.06	21.85	7.35	8.76
2.04	35.71	6.77	7.99
3.18	50.49	6.50	7.63
4.99	75.69	6.45	7.53

Source: Bureau of Mines, Reference 18.

Table 2-8. Cost Estimates for Underground Mines - One Million Tons/Year (\$1974)

Type	Cont. ^a SH/SL ^b	Conv. ^c SH/SL	Cont. Drift	Conv. Drift	Cont. SH/SL	Conv. SH/SL	Cont. Drift	Conv. Drift
Seam Thickness Item	6'	6'	6'	6'	4'	4'	4'	4'
Capital Investment (\$10 ⁶)	25.70	25.93	15.21	15.53	27.92	27.84	17.51	17.40
Operating Cost (\$/ton)	9.17	9.86	8.33	9.00	9.79	10.49	8.93	9.63
Selling Price (\$/ton)	13.14	13.81	10.29	11.03	14.21	14.85	11.35	11.99

Source: FEA, reference 12, p. 21.

^aCont. = continuous

^bSH/SL = shaft/slope

^cConv. = conventional

Table 2-9. Cost Estimates for Underground Mines - Three Million Tons/Year (\$1974)

Type	Cont. ^a SH/SL ^b	Conv. ^c SH/SL	Cont. Drift	Conv. Drift	Cont. SH/SL	Conv. SH/SL	Cont. Drift	Conv. Drift
Seam Thickness Item	6'	6'	6'	6'	4'	4'	4'	4'
Capital Investment (\$10 ⁶)	41.91	41.97	31.47	31.51	48.27	48.17	37.39	37.21
Operating Cost (\$/ton)	7.54	8.08	7.18	7.81	8.13	8.83	7.83	8.53
Selling Price (\$/ton)	9.33	9.94	8.52	9.18	10.44	11.09	.54	10.25

Source: FEA, reference 12, p. 21.

^aCont. = continuous

^bSH/SL = shaft/slope

^cConv. = conventional

Table 2-10. Cost Estimates for Surface Mines (\$1974).

Overburden MTPY	$\frac{18:1}{1}$	$\frac{15:1}{1}$	$\frac{10:1}{1}$	$\frac{18:1}{3}$	$\frac{15:1}{5}$	$\frac{10:1}{5}$	$\frac{5:1}{5}$
Item							
Capital Investment (\$10 ⁶)	22.53	19.89	16.65	63.24	95.85	67.48	43.39
Operating Cost (\$/Ton)	5.43	5.09	4.57	4.66	3.98	3.26	2.33
Selling Price (\$/Ton)	9.26	8.46	7.51	8.33	7.42	5.60	3.78

Source: FEA, Reference 12, p. 22.

In contrast to these basic mining cost estimates, the market price for coal may fluctuate with available mining capacity, coal demands, environmental regulations, materials, manpower and capital availabilities, substitutable fuel economics, and uncertainties such as coal miners' strikes. This has recently been most evident, when after an historically stable price (1948-1969), the average spot price of coal tripled between September 1973 and November 1974. This relatively abnormal price surge was primarily a result of a quadrupling of the price of imported oil, which to some extent is a substitute fuel, and to the threat of a mining strike in November 1974 (27). Recent spot prices (mid 1975) have dropped to half the level they had reached in late 1974, and are still less than one-half the cost of equivalent energy obtained from residual oil. Contract prices have more gradually increased, having about doubled by early 1975 as compared to pre-embargo prices (27, Fig. 1, p. 2).

Coal prices have had the characteristic behavior of prices in a natural-resource market where the short-run elasticity is low, i.e., sudden increases in demand produce rapid increases in price. New capital investments are required and new mines require several years to become productive. In addition, since coal supplies over 40 percent of U.S. electric power needs, the electric utilities play a major role in establishing the price of coal. Automatic fuel adjustment clauses allow regulated utilities to pass through their fuel cost increases. This reduces the incentive for utilities to resist coal price increases. Also, in the short run, utilities can neither rapidly substitute other fuels for coal nor curtail output because of their public status. Less than 10 percent of the total U. S. electric generating capacity is convertible from coal to oil (28).

Coal prices during the next decade will depend on several factors, most notably the production capacity of western coal. The development of western coal reserves will provide substantial pressure for stabilizing prices, if transportation and other significant constraints discussed below can be overcome. Because of its large long-term price elasticity, i.e., its vast supply, western coal should be available at FOB mine prices of from \$5 to \$6 per ton (1975 prices), regardless of the long term demand (27, p. 10). This will place a price ceiling on coal from other sources, depending on transportation charges as discussed in Chapter 4, and will maintain the economically competitive position of U. S. coal in domestic as well as world markets.

2.3. CONSTRAINTS AND UNCERTAINTIES

The dynamics of the coal industry and the future levels of coal production and price will be governed by various constraints and uncertainties; environmental regulations, surface mining standards, coal leasing policy, oil and gas prices and availabilities, nuclear power growth, transportation capacity, construction and equipment procurement, water needs, state severance taxes, labor costs and future energy demands will all influence coal development.

Air and Water Quality

Controlling residual emissions from coal-fired power plants within the limitations imposed by the Clean Air Act will affect the technical and economic capability to burn some coal in new and existing plants. In addition to Federal Air Quality Standards, State Implementation Plans are being established which are often more stringent.

Water quality is affected by disruption of ground water systems when mining, by water emissions from cleaning and conversion technologies, and by potential discharges from sludge ponds and land fills. Water rights and water quality legislation could constrain a full coal development potential.

Surface Mining Standards

Surface mining at least temporarily disrupts the land and supported ecosystems (29). The rapid growth of surface coal mining has in the past taken place with little control and reclamation practice. Individual states have enacted surface mining and mined land reclamation laws (30). Recently, the Department of the Interior has announced new federal regulations governing the surface mining of coal on federally owned lands (31).

Environmental Legislation (NEPA)

Section 102 (2) (c) of the National Environmental Policy Act of 1969 (NEPA) requires that the Federal Government prepare a detailed statement regarding Federal actions with the potential for significantly affecting the quality of the human environment (32). While protecting the environment, this procedure requires time and expense, and produces lengthy documents (33,34). It has also created delays due to court cases involving legal acceptance of its provisions (47).

Coal Leasing Policy

The Federal Government owns over 60 percent of coal deposits on western lands (34). The rate and manner in which these lands are leased for coal development may have a large impact on the price and availability of western coal.

Synthetic Oil and Gas

The utilization of coal depends on the degree of use, availability and substitutability of competing fuels. Domestic natural gas prices are increasing while its availability is rapidly decreasing. If prices for naturally available oil and gas continue to increase relative to coal, a coal synthetics market may be created. This could greatly increase the demand for coal.

Nuclear Power

Nuclear power may be the major future competitor with coal for electric energy production. The growth of nuclear power could be extensive, however it faces its own constraints and uncertainties. These include: increasing uranium prices (35), construction cancellations and delays (36), limited uranium enrichment capacity, uncertainties in the development of the breeder reactor, environmental and safety hazards and the political process (37).

Transportation

Transportation of coal has major cost and regional availability implications. Large major new investments are required to move coal from the west to eastern and midwestern points of utilization. These investments may be made in railroad capacity, coal-slurry pipelines or expanded inland waterways, which is the subject of much current debate. Coal transportation is discussed in more detail in Chapter 4.

Construction and Equipment

There has been an historical inventory of U.S. production capacity of from 50-100 million tons per year over normal production levels. This has been the source of "spot" coal and has provided a cushion for fluctuating demands (12, p. 44). This inventory has slowly been diminishing, and with it the inventory of equipment that moved in and out of the industry in response to rapid changes in demand. Therefore, new construction and operating equipment is now required which has inherent requisition delays. In addition, new mine openings require additional equipment and capital expenses, and new mines do not become fully productive for several years. Manufacturers of both surface and underground mining equipment have had difficulty in obtaining raw materials, most notably steel plate for draglines and shovels (12, p. 49).

Water

Large increases in coal production may have attendant regional water demand impacts, especially if a synthetic industry is commercialized. Major problems may be encountered in the west where available surface waters are in short supply. The allocation of scarce water for the alternative uses of agriculture, oil shale, coal development, and other industries may be required. The major use of water is for cooling needs at conversion facilities, and is relatively large in comparison with water requirements for coal mining and cleaning (38,39). Water requirements are discussed extensively elsewhere (40-46).

Severance Taxes

In addition to reclamation bonds, states may impose a tax on each ton of coal produced. These taxes would increase consumer prices of

coal, especially from western deposits.

Labor Costs

Average labor costs per ton of coal, which represent about 25 percent of the cost of production, have risen significantly since 1970 (27, p. 3). Average labor costs in 1970 were about \$2.40 per ton, but by 1975 labor costs had risen to about \$4.50 per ton. Much of this increase was due to reductions in output per manhour in underground mines during this period.

Also, the supply of domestic mining engineers has been inadequate (12, p. 47). This will undoubtedly increase the labor cost component of coal production.

Electrical Energy Demand and Growth

Because the electric power industry uses about 70 percent of U.S. bituminous coal, growth patterns in electrical energy will have a significant impact on coal production. A difference in the current annual rate of electrical energy output of between 3 and 7 percent is equivalent to a difference of as much as 600 million tons per year of coal consumption in 1985.

Geology

Coal geology is an important aspect of mining and production (48). In the long term, coal operators should plan to take better advantage of the geologic information which is available to them (49).

CHAPTER 2

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CHAPTER 3

COAL BENEFICIATION TECHNOLOGY

Coal may be prepared or beneficiated before transportation and utilization by a number of technologies which include mechanical and physical cleaning, crushing, screening, chemical preparation, solvent refining and blending. In addition to these more commercial processes, which are described in this section, other techniques are being researched (5, 6). Coal refining or coal-synthetics technologies such as gasification and liquefaction are not generally discussed in this section. An extensive literature is available elsewhere (e.g. 7-13).

Coal preparation technologies can produce an upgraded product from both an economic and an environmental point of view. An economic advantage may accrue because the beneficiated coal contains less mineral matter, including ash and sulfur, which will reduce transportation and handling costs. Sludge and ash disposal expenses at the power plant are also reduced. Sulfur oxide and particulate emissions are reduced from power plant stacks, in some cases to acceptable standards for low sulfur or largely pyritic sulfur coals. In general, coal preparation has several significant benefits, which primarily include (1):

- Removal of sulfur
- Removal of ash and refuse material
- Concentration of carbon which increases energy content by weight
- Reduction in concentration of some trace elements (although nitrogen compounds may be unaffected)
- A uniform quality of product including ash, moisture and energy content.

Coal beneficiation can achieve several levels of product quality. The levels are determined by product specifications, processing economics, processing technology and coal characteristics. In addition, the price of raw coal, the demand for processed coals, and environmental regulations are important considerations.

This section includes an historical background and discussion of current trends in coal preparation technologies, an overview of the various technologies available based on physical and chemical methods, and a summary of cost estimates. It also includes a description of sulfur and ash reduction potentials of U.S. coals, environmental implications of coal preparation technologies, and some constraints and uncertainties that face the coal preparation industry.

3.1. PHYSICAL COAL PREPARATION

Physical coal preparation is the mechanical cleaning and sorting of particles of coal and its impurities. Physical preparation has been used extensively for some time, especially for coals dedicated for carbonization (industrial, metallurgical) and for export. Currently about 40 percent of the coal burned by the electric utilities is subject to some kind of coal preparation (15).

Historical Background and Trends

Mechanical cleaning of coal in the United States was first practiced around 1880 (19), although the first systematic studies of coal characterization were not conducted until 1924 (20). The U.S. Bureau of Mines has since conducted extensive studies of the washability characteristics of U.S. coals (21-24). The Environmental Protection Agency has also conducted studies related to coal quality and cleanability (29).

The growth of the mechanical cleaning industry is shown in Table 3-1. While the number of plants has approximately doubled in 30 years since the early 1930's, the amount of cleaned coal has increased by an order of magnitude, to some 60 percent of the total coal production by 1958. From the mid-1960's to the early 1970's the industry experienced a slight decline. This trend seems to have stabilized (11); however, the number of coal cleaning plants has continued to decline. Recent trends are shown in Table 3-2, and historical equipment use is shown in Table 3-3.

Future coal cleaning activity will likely increase due to the demands for low-sulfur coal. However, coal cleaning causes losses which reduce the total available supply, and higher mine prices may cause the additional cost of preparation to appear uneconomic (25). Some current recommendations include the proposal to initiate a massive program to upgrade existing coal beneficiation facilities and to increase the number of cleaning plants by 40 percent over current levels by 1985 (2).

Historically, the primary reason to beneficiate coal was to produce a more uniform and hence a more saleable product, and thus to derive an economic advantage by being able to supply a variety of coal markets. The introduction of emission standards for air pollution has added an additional dimension to consider for coal preparation planning, especially with respect to coal-fired electric utility markets. Future trends in coal preparation technology are discussed below. Also, constraints and uncertainties that have influenced the industry are described in this section.

Table 3-1. Historic Trends for Mechanical Cleaning at Bituminous Coal and Lignite Mines in the United States

<u>Year</u>	<u>Total Production (10³ tons/year)</u>	<u>Number of Plants</u>	<u>Cleaned Coal (10³ tons/year)</u>	<u>Percent of Total Mechanically Cleaned</u>
1928	500,745	236	28,783	5.7%
1938	348,545	374	63,455	18.2
1948	599,518	502	189,880	30.2
1958	410,446	573	259,035	63.1
1968	545,000	-	345,000	63.3

Source: U.S. Bureau of Mines

Table 3-2. Recent Trends for Mechanical Cleaning and Crushing of R.O.M. Coal (10³ tons/year)

	<u>1971</u>	<u>1972</u>	<u>1973</u>
Total Coal Production	552,200	595,400	591,700
Number of Cleaning Plants	411	408	382
Mechanically Cleaned R.O.M. Coal	361,200	398,700	397,600
% of Total	65%	67%	67%
Number of Crushing Plants	932	925	861
Mechanically Crushed R.O.M. Coal	323,200	445,400	415,200
% of Total	59%	75%	70%

Source: U.S. Bureau of Mines Minerals Yearbook

Table 3-3. Trends for Mechanical Cleaning of Coal by Type of Equipment
(Percent of Clean Coal Produced)

<u>Type</u>	<u>Year</u>		
	<u>1952</u>	<u>1962</u>	<u>1972</u>
Jigs	43%	50%	44%
Dense-Medium Processes	14	25	31
Concentration Tables	2	12	14
Flotation	-	2	4
Other	40	11	7

Source: U.S. Bureau of Mines Minerals Yearbook

Technology Overview

Physical coal preparation methods utilize differences in the physical properties of coal and its mineral impurities to achieve a degree of beneficiation. Differences in particle size characteristics, appearance, specific gravity, and surface, magnetic and electrostatic effects are the primary physical properties that are used for designing and operating coal preparation technology.

Coal preparation is usually accomplished at or near the mine site in plants ranging in capacity from 50 to 1800 tons per hour. Processes in common use may involve a combination of the following unit operations:

- Comminution (crushing) to free physically bound component structures
- Particle sizing (screening and classification) depending on hardness, texture and chemistry
- Density separations of particles suspended in fluids depending on relative specific gravities and surface effects
- Dewatering and thermal drying to reduce moisture content.

Common coal preparation circuits may contain a number of technologies which use these unit operations. Detailed discussions of these technologies are available (14-16) and various summaries have been published (26, 27, 28). Also, information from vendors is abundantly available (e.g., 30). A list of common coal preparation techniques includes: storage, blending, cleaning, sizing, washing, dewatering, drying and handling.

Storage. Coal storage may be both underground or on the surface; underground storage may help control spontaneous ignition of the coal pile. Storage accomplishes the inventory function of leveling fluctuations in plant feed and supply, as well as market demand. It also reduces transportation costs by allowing for prompt loading and unloading of unit trains, etc., and helps facilitate blending. Storage capacities should be least 1/2 hour of rated plant capacity (16).

Blending. Normally, the function of blending is to split the coal stream apart by size increments, differentially process, and then recombine by size increments to achieve a desired quality. A less common type of blending is to create a mixture of coals from two different mines or seams, although this is receiving increasing attention (72).

The use of coal blending to achieve a desired quality of product has not been practiced to any extent using utility-scale facilities. A common practice in the coke and metallurgical coal industries, blending is only now being planned for significant scale operations using coal to produce electric power (66, 67, 70). Blending may be practiced to reduce average sulfur and ash content, to upgrade energy content or to produce a more uniform product.

Large-scale blending is accomplished by the horizontal layering of materials in beds using traveling stackers or other mobile equipment (66). The number of layers in the bed determines the accuracy of the output. Vertical slicing of the bed using loaders, shovels or reclaimers then creates a blended coal of the desired quality (71). The Four Corners Power Plant has been using blended coal from different sections of the Navajo mine in New Mexico (66, 67). The Four Corners blending system consists of ten 30,000-ton piles, which also act as a coal storage for surges in feed to the power plant. Experience at this facility indicates that regulation of the btu content is of primary importance, which establishes specifications for the other coal characteristics.

Coal management in general is being increasingly discussed for consideration in producing electric power (68). Blending of coal may be able to help meet air quality regulations and reduce some of the costs of electric power production; however, the characteristics of blended coal may be difficult to predict (70). Two coals which would not result in slag when burned individually, may cause slagging when fired together. Most boilers are designed to burn a specific type of coal.

The cost for coal blending in small utility-scale facilities has been estimated to range from about \$1.00/ton to \$0.65/ton (assumed \$1975) for capacities between one and ten million tons per year of blended coal

respectively (69). The capital cost for a 75,000 tpd blending and stockpiling plant at first quarter 1975 prices has been estimated to be about \$67.4 million (40). This is equivalent to about \$0.45/ton at an 18% capital recovery factor. The actual cost is dependent on the variation in feed stock characteristics, the required blended coal tolerances, capacity and load-duration patterns.

Cleaning. Preliminary breaking and rough cleaning are usually accomplished together. Raw coal is fed to a rotary-screen-type breaker which accomplishes both size reduction and gross refuse rejection. The coal fines may be screened and routed around the cleaning operation.

Sizing. The crushed and rough cleaned coal is often fractionated by size using screens. Often these screens vibrate or shake using mechanical mechanisms.

Washing. Coal and its impurities are then usually separated based on size differential, specific gravity and surface effects. Conventional washing technologies include jigs, cyclones and tables. Jigs produce particle stratification in which the particle rearrangement results from an alternate expansion and compaction of a bed of particles by a pulsating fluid flow. Cyclone separation is based on centrifugation of a slurry, and tables depend on the stratification of columns of particles on a flat or riffled surface caused by differential motion and gravitational flow.

These techniques can become rather complicated, and the physical principles themselves may not be completely understood. In some cases a mathematical analysis has been attempted (32). Washing may also be conducted using froth flotation as discussed below. Other concentration techniques which use dry particles, air or electrostatic and magnetic principles are not generally discussed here.

Dewatering. Moisture collects rapidly as the particle size decreases because of an increase in surface area. Dewatering is desirable to prevent freezing of the coal and helps decrease transportation and handling costs. Moisture in coal also affects the heat rate at the power plant. Depending on particle size, dewatering may be accomplished by use of screens, centrifugal dryers or filters. Dewatering technology also includes water clarification and desliming.

Drying. Thermal drying is sometimes used with fine coals and is about the only way to reduce surface moisture to as low as 2 to 3 percent by weight. Fluidized beds and particle suspension are used.

Handling. Handling technologies are designed for the movement of coal and water as well as the refuse streams. Coal must be unloaded, stored, processed and then stored or loaded for transportation. This requires a system of bins, conveyors or booms and other equipment. Water must be obtained from a reliable source, cycled and then recycled or reclaimed, which requires pumps, tanks and treatment equipment. Refuse material must be properly disposed or recovered. In some cases it may be economic to recover the energy content of the refuse which may be as high as 10,000 Btu/lb (33-35).

Since U.S. coals are not homogeneous, coal preparation processes are usually designed and operated for site-specific applications. There are standardized technologies, but each plant is usually unique. However, the range of coal preparation now being practiced may be generalized according to the level of beneficiation, as follows (2):

- Level 1: No preparation, direct utilization of run-of-mine coal
- Level 2: Removal of gross noncombustible impurities with control of particle size and promotion of uniformity (approximately 95% weight yield, 99% btu yield, with little change in sulfur content)
- Level 3: Single-stage beneficiation following minimal component liberation. Particle sizes less than 3/8 inch (fines) usually not prepared (approximately 80% weight yield, 95% btu yield, with limited ash and sulfur removal)
- Level 4: Multi-stage beneficiation with controlled liberation usually incorporates dewatering and thermal drying (approximately 70% weight yield, 90% btu yield, with maximum ash and sulfur removal).

The technical limitations and preparation costs primarily relate to the size of coal particles (in addition to the scale of operation). These particles are generally irregular in shape and may be less than one micron in size. Particles smaller than 50 microns cannot be practically separated. To be separable, impurity-containing particles must be physically freed from and have masses greater than the purer coal particles. Coal may be more finely ground than impurities, and thus comminution aids in the separation process. However, coal particles must be size (and weight) differentiated, so that a large amount of crushing and grinding may actually increase the impurity content of "cleaned" coal. This is due to the general fact that high organic constituents tend to remain in the light separated fraction. The characteristics of crushed coal also depend on the chemical nature of the coal structure. Thus pyritic and marcasitic sulfur, which are sulfur bound with iron as FeS_2 , may be physically freed and therefore removed from coal particles, organically bound sulfur. (The washability characteristics of U.S. coals are discussed below).

Technological trends in coal preparation show an increased use of heavy media for preparation of coarse coal for metallurgical and steam coal markets (31). This trend is evident in Table 3-3. Also, froth flotation systems are being increasingly used, especially for the cleaning of fine coal. This phenomena is based on the property that the surface of coal particles is not preferentially wetted by water, unlike the surfaces of the mineral impurities it contains. Thus when air is bubbled through a suspended mixture of finely ground coal, the unwetted coal particles attach themselves to the air bubbles and are concentrated in the froth.

The hydrocyclone has a future in U.S. coal preparation plants (31, p. 57). Dense-medium cyclones can provide for sharp separations and exceptional operating flexibility (23). Also, dewatering and thermal drying will be increasingly used for additional economic benefits as markets expand and transportation distances increase. These techniques are now being considered for use with western coals (27, coal age, p. 106).

Multi-stream coal cleaning systems that produce multiple-levels of beneficiated coal to serve more than one plant in a power complex appear to be economically and technically feasible (27, coal age, p. 86, 28). These systems may be used in combination with flue gas desulfurization to help combinations of new and existing power plants to meet air quality regulations.

In addition to proven devices such as jigs, straight cyclone and table circuits, it has been projected that future coal preparation plants built in the U.S. will have the following features (31, p. 98):

- Coarse coal - heavy media
- Fine coal - hydrocyclones or hydrocyclones combined with tables or heavy media
- Mechanical dewatering -screen centrifuges or vacuum filters
- Thermal drying - fluid bed dryers with vacuum filters
- Water clarification - centrifuges, filters and presses.

Environmental Factors

There are several important environmental factors for coal preparation involving water, land and air resources.

Water. The effluents from coal preparation facilities and water drainage from plant and refuse disposal sites often contains fine coal material in suspension. This so called "black water" is usually acidic and contains chlorides, sulfates and trace metals (16, Chapter 17). Although most coal preparation processes use wet techniques, practically all new facilities are designed to operate on a closed water circuit. The use of water for dust control is a source of water pollution, especially as more coal fines are processed.

The volume of water consumption and discharge can be significant depending on the coal cleaning circuit design. About 20 percent new water was required in coal preparation plants in 1962, of which 5 percent was consumed and 15 percent discharged (16, p. 17-6). Modern plants may be designed to minimize water losses, which complicates the design and operation (increasing costs), but does enhance total coal yields.

Water treatment within the preparation plant to control water quality and equipment corrosion is now commonly practiced. Suspended solids are removed by clarifier-thickeners. If settling basins are used, pond liners to prevent ground water contamination may be utilized.

Land. The reject refuse material from a coal cleaning circuit requires disposal. Material yields can range from 60 to 90 percent so that refuse material can be as high as 40 percent of the feed. For a typical plant processing 500 tons of coal per hour, about 1,000 tons of refuse must be disposed of daily. This is roughly equivalent to the solid waste generated by a city of 400,000 people (17, p. 1-67). Precautions in refuse disposal include water pollution (run off and ground water seepage), refuse pile stability to prevent erosion, and esthetics. Studies to stabilize waste, such as cementation, are currently being conducted (28).

Air. Air pollution from coal preparation facilities may be caused by fugitive dust from bulk handling of coal products, pneumatic cleaning processes or thermal drying. Increased air pollution potential results from fine coal cleaning. Also, the spontaneous ignition of coal piles creates gaseous and particulate emissions. However, the economic impact for air pollution control at the coal preparation plant may be considered small (18).

Coal Cleanability Characteristics

The sulfur content of U.S. coals varies from 0.1 to 10.0 percent by weight. Sulfur in coal has three components: (i) organic sulfur, which is chemically bound to the carbon, hydrogen and oxygen components, (ii) sulfide sulfur, which is mainly in the form of pyrite or iron disulfide, and (iii) sulfate sulfur, which is a minor oxidized-sulfur component. Only the sulfide and sulfate forms in coal may be removed by physical cleaning. The sulfate component is water soluble, while the pyritic form is a dense material with respect to coal, and like coal, it is water insoluble unless oxidized. The extent of sulfur removal primarily depends on the amount of sulfide or pyritic sulfur and its physical characteristics. Very small (less than about 50 microns) and dispersed pyrite particles are difficult to remove. These properties may be determined by geologic formations on a regional basis, the influence of mining techniques (3), and by the type and extent of handling and crushing operations that may precede washing.

The Bureau of Mines has conducted extensive investigations of the sulfur and ash reduction potential of U.S. coals (22, 24). These data have been summarized in Table 3-4 for a maximum range of crushing and density separation levels according to energy recovery (24, p. 296-323). The data show that there are significant differences in cleanability characteristics even for large aggregated regions. Northern Appalachian coal contains considerably more sulfur, (in both total and pyritic forms) than coal from Southern Appalachia; percentage wise it has more sulfur reduction potential. The sulfur reduction potential for western coal is not as significant as that for midwestern and eastern coal. The average reduction in pounds SO₂ per million btu is generally not sufficient to

Table 3-4. Coal Cleanability Characteristics of United States Coals

Region	Preparation	Method	Ash Percent		Pyritic Sulfur		Total Sulfur
	Top Size (inches)	Btu Rec- overy (%)	Average	Sigma	Average	Sigma	Average
Northern Appalachia	Raw	Raw	15.1%	6.5	2.01%	1.3	3.01%
	1-1/2	90%	8.6	3.6	1.06	0.8	2.06
	14 mesh	50	4.2	1.8	0.31	0.3	1.37
Southern Appalachia	Raw	Raw	11.0	6.0	0.37	0.4	1.04
	1-1/2	90	4.7	2.3	0.17	0.2	0.90
	14 mesh	50	3.0	0.7	0.07	0.1	0.81
Alabama	Raw	Raw	9.5	6.2	0.69	0.8	1.33
	1-1/2	90	7.3	4.1	0.64	0.8	1.38
	14 mesh	50	3.8	1.7	0.22	0.2	1.04
Eastern Midwest	Raw	Raw	14.2	4.8	2.29	1.0	3.92
	1-1/2	90	7.4	2.0	1.01	0.5	2.73
	14 mesh	50	3.6	0.9	0.48	0.2	2.17
Western Midwest	Raw	Raw	16.2	6.6	3.58	1.9	5.25
	1-1/2	90	9.5	4.0	2.15	1.3	3.91
	14 mesh	50	4.6	1.6	0.52	0.4	2.96
Western	Raw	Raw	8.9	4.3	0.23	0.3	0.68
	1-1/2	90	6.1	2.6	0.10	0.1	0.54
	14 mesh	50	3.8	1.1	0.06	0.0	0.50
Total	Raw	Raw	14.00	6.3	1.91	1.5	3.02
	1-1/2	90	7.9	3.5	1.00	0.9	2.16
	14 mesh	50	4.0	1.5	0.40	0.4	1.68

Table 3-4 (Cont.)

<u>Region</u>	<u>Total Sulfur</u>	<u>Weight Percent</u>		<u>Btu Per Pound</u>		<u>Pounds SO₂ Per Millions Btu</u>	
	<u>Sigma</u>	<u>Average</u>	<u>Sigma</u>	<u>Average</u>	<u>Sigma</u>	<u>Average</u>	<u>Sigma</u>
Northern Appalachia	1.6	100.0%	0.0	12400	1080	4.8	2.7
	1.2	83.5	4.6	13700	720	3.1	1.8
	0.9	42.8	3.2	14300	600	1.9	1.3
Southern Appalachia	0.6	100.0	0.0	13300	930	1.6	1.0
	0.4	83.5	4.5	14200	430	1.3	0.6
	0.2	44.0	1.7	14400	330	1.1	0.3
Alabama	0.9	100.0	0.0	13700	880	2.0	1.5
	0.9	85.0	2.3	14100	590	2.0	1.3
	0.3	43.8	0.5	14600	140	1.4	0.4
Eastern Midwest	1.2	100.0	0.0	12200	750	6.5	2.1
	0.8	83.4	4.0	13100	400	4.2	1.3
	0.7	43.3	2.6	13600	250	3.2	1.1
Western Midwest	2.3	100.0	0.0	12100	1200	9.0	4.5
	1.8	83.3	4.5	13000	940	6.2	3.2
	1.2	42.6	3.0	13600	550	4.4	1.8
Western	0.3	100.0	0.0	12400	800	1.1	0.6
	0.1	86.1	2.2	12800	680	0.8	0.2
	0.1	45.9	1.8	12900	530	0.8	0.2
Total	1.9	100.0	0.0	12600	1060	4.9	3.4
	1.4	83.7	4.3	13500	770	3.3	2.2
	1.1	43.2	3.0	13900	670	2.4	1.6

Source: Bureau of Mines, reference 24, p. 296-323.

meet federal standards, except for western coals (which already generally meet standards), and possibly coals from Southern Appalachia. However, a significant variance exists for such large regions so that some estimates of the total cleanability potential of U. S. coals may be determined. These estimates are shown in Table 3-5 (24). With some cleaning, about one-fourth of U. S. coals when combusted may meet new source performance standards for sulfur dioxides. However, even at maximum cleaning capability, only one-third of U. S. coals could meet present environmental regulations when burned directly in a power plant.

Constraints and Uncertainties Affecting Coal Preparation

The coal preparation industry is currently in a period of transition and future expansion. Several technical, environmental and legal issues pose constraints and uncertainties. These factors include energy recovery, sulfur removal, coal fines, SO₂ emissions, noise control, water disposal, and governmental laws and regulations.

Energy Recovery. Depending on the level of beneficiation required, significant amounts of energy may be discarded with the separated reject waste materials. This is an inherent physical limitation of mechanical coal preparation methods. However, under certain technical and economic conditions, this pyrite-coal material may be utilized (33-35). The economics of refuse utilization are briefly reviewed below.

Sulfur Removal. Inherent sulfur, mostly organic but some pyritic, cannot presently be removed using physical coal preparation techniques. The percentage of organic sulfur that remains in the cleaned coal may actually increase since it tends to concentrate in the light separated fraction.

Coal Fines. The preparation of the fine coal particles presents technical, economic and environmental problems. Energy and material losses increase as the particle size is reduced. Some size reduction aids the separation process, however, fine particles (smaller than about 50 microns) cannot be practically separated. Dust problems, water quality and refuse disposal problems all increase with an increasing proportion of coal fines.

SO₂ Emissions. SO₂ emission standards pose serious constraints on the direct utilization of physically prepared coal. As shown in Table 3-5, about 14 percent of raw U.S coal may be burned directly while meeting current new source performance standards. However, even with

Table 3-5. Estimates of Cleanability Potential for U.S. Coals

Region	Percent of Coals Meeting New Source Performance Standards for Sulfur Dioxides		
	Raw	90% Btu Recovery 1-1/2 inch top size	50% Btu Recovery 14 mesh
Northern Appalachia	4%	12%	31%
Southern Appalachia	35	50	63
Alabama	30	30	40
Eastern Midwest	1	2	4
Western Midwest	3	6	6
Western	70	94	98
Total U.S.	14%	24%	32%

Source: Bureau of Mines, reference 24

maximum preparation (50% energy recovery) only about 32 percent of U.S. coals could be used directly.

Noise Control. Vibration and vibrating materials, which are inherent to coal preparation, are often the source of excessive noise. Many tests and control programs are currently being conducted (28, p. 97).

Waste Disposal. The trend in coal preparation design and operation is to have closed water-and-solids circuits. This practice will increase both capital and operating costs. Underground mine disposal will likely be the common practice within 10 years (31, p. 56).

Laws and Regulations. Federal and State laws and regulations which affect the coal preparation industry include, NEPA, The Clean Air Act, The Federal Water Pollution Control Act, The Occupational Health and Safety Act, the 1969 Coal Mine Health and Safety Law and The MESA Noise Regulations.

Coal Preparation Costs

Accurate cost estimates for physical coal preparation technologies are difficult to generalize. Each plant is unique, as the design of cleaning circuits is primarily dependent on the physical and chemical properties of the feed coal and the cleaning objectives. This section contains a summary of some published costs estimates as well as discussion of the economics of refuse utilization and disposal. A general cost estimating procedure including some preliminary cost estimates is available (16, Chapter 5).

Capital Cost. A literature survey of capital cost estimates over roughly the last ten years was conducted and is shown in Table 3-6. Both an economy of scale and an increased cost with preparation level are evident. Plant circuit details are important and are available in a number of references as noted. Capital costs were accounted for in terms of raw coal fed to the plant. The range of capital costs may be significant depending on the type of coal preparation required; small complex plants have the greatest cost. Also, some capital cost estimates may include direct as well as indirect expenses.

The extent of fine coal cleaning greatly influences coal preparation capital costs. Normally about 5 to 10% of the ROM coal is handled in the form of fine particles (less than approximately 3/8"). The capital cost for a 200 tph plant was noted to increase from 2.1 million to about 4 million dollars (\$1966) when the amount of fines handled increased from 10% to 100% (14 p. 3-121). A significant fraction of the preparation of fine coal may be accounted for by thermal drying (about 25%, 38, p. 34).

It has been estimated that it generally costs three times as much to install fine-coal cleaning and drying as it does to install only coarse coal cleaning and dewatering (16, p. 5-14).

Operation and Maintenance Cost. A survey of operation and maintenance cost estimates is shown in Table 3-7. The majority of this cost components is variable with respect to plant output so that the average plant yield in weight percent is also included in Table 3-7. Again the extent of fine coal preparation is significant and may easily double the operating cost.

Total Annual Cost. The percent of rejection and the rate of capital depreciation have the greatest effect on total annual preparation cost. Also, the percentage utilization of the plant can significantly affect amortized capital-related costs.

Capital costs have general economies of scale which have been estimated for large-scale coal processing facilities (41). The cost per ton of output generally decrease with increasing plant size. The per ton capital-related output cost is inversely proportional to plant utilization, i.e. hours per year of operation.

Table 3-6. Physical Coal Preparation Capital Cost Survey.

Plant Size (Tons/Hour Feed)	Type of Plant ^a	(\$/ton/hour feed)	Year	Source ^b
500+	Minimal plant-crushing, sorting	2,000	11/70	36, p. 44
500+	Medium Plant-tables, cyclones, etc.	8,000	11/70	36, p. 45
500+	Maximum plant-high quality	14,000	11/70	56, p. 45
200	Fine coal cleaning plant	10,500	6/66	14, p.3-119
1000	3/8 in. Top size, jigs, dense media flotation and drying (Plan A)	5,600	6/65	14, p. 121
600	Moderate plant	12,800	6/74	4
430 est. ^c	Plant A - Level 3	26,200	6/74	38, p. 34
490 est.	Plant A - Level 4	51,500	6/74	38, p. 34
140 est.	Plant B - Level 3	30,500	6/74	38, p. 34
160 est.	Plant B - Level 4	55,200	6/74	38, p. 34
200 est.	Multi-stream plant	175,000 est. ^d	1/76	28, p. 86
1350	Double washing, slight preparation	3,700	3/75	39, p. 62
3100	Baum Jig - standard	16,700	1/75	40, p. 29
3100	Heavy Media - standard	22,500	1/75	40, p. 37
500-1000	50-60% plus 3/8 in., washing plus 3/8 in. only	3,000	1968	16, p. 5-13
500-1000	50-60% plus 3/8 in., washing plus 3/8 in. washing and drying minus 3/8 in.	2,500 (plus 3/8 in.) 5,000 (minus 3/8 in.)	1968	16, p. 5-13

^a Detailed plant circuits are available in References 4, 28, 36, 37 and 40.

^b Reference numbers at end of chapter.

^c Estimated by author.

^d This cost seems abnormally high " . . . \$35 million; . . . 1.3 million tpy," 28, p. 86.

Table 3-7. Physical Coal Preparation Operation and Maintenance Cost Survey.

Plant Size (Tons/Hour Feed)	Type of Plant ^a	Average ^b Plant Yield (Weight %)	O&M Cost ^c (\$/Ton)	Year	Source ^d
700	Heavy Media for coarse coal, tables for fine coal, thermal dryers	70 80 90	0.66 0.56 0.47	11/70	36, p. 100
1000	Baum jigs, piston jig for fines	90	0.19	11/70	36, p. 203
500	Screens, Flotation cells, tables and heat dryers	70 80 90	0.64 0.53	11/70	36, p. 206
1000	3/8 in. top size, gigs, dense media, flotation and drying (Plan A)	78	0.37	6/65	37, p. 123
140-430	Level 3	80	0.30-0.60	6/74	38, p. 34
160-490	Level 4	70	0.80-1.60	6/74	38, p. 34
300	40% minus 3/8 in., includes labor, power, supplier and depreciation	80	0.40 (plus 3/8 in.) 0.75 (minus 3/8 in.)	1968 1960	16, p. 5-14 16, p. 5-14

^a Detailed plant circuits are available in References 36 and 37.

^b Total of all size fractions.

^c Generally does not include depreciation.

^d Reference numbers at end of chapter.

Operating and maintenance costs are the sum of two components, direct plant costs, and refuse handling and disposal expenses. Direct costs include labor, maintenance, supplies and utilities, and are roughly inversely proportional to plant yield. Refuse handling and disposal costs vary directly with plant yield and may include an economy of scale.

Data has been compiled from extended records of a plant operating at 500 tons per hour, washing 5 by 0 inch coal with about 40 percent of the raw feed being 3/8 by 0 inch. Cleaning circuits included centrifuging, filtering and hot drying the fines. About 15 % of the input was rejected. These data are summarized in Table 3-8 and are most applicable for plants processing more than 250,000 tons per year (16, p. 5-15). More recent detailed cost estimates for physical coal cleaning are shown in Table 3-9. The cost of cleaning itself in mid-1973 has been estimated to be between about \$1.50-\$2.00 per ton of clean coal. In comparison, the cost of ROM coal at \$10 per ton, with 86% yield, is equivalent to \$11.60 per ton of clean coal. Thus the selling price for cleaned coal would range from about \$13.00-\$13.50 per ton.

Refuse Utilization and Disposal

The cost of refuse disposal is a significant additional expense for coal preparation processes. Detailed capital and operating costs have been estimated for typical refuse disposal operations in Kentucky and Alabama (42). These costs averaged about \$0.27 per ton of refuse or \$0.09 per ton of cleaned coal in 1969 dollars. An added cost of about one cent per ton of refuse is required for site reclamation. Other data suggest that refuse disposal costs are about \$0.50 per ton of refuse, depending on plant yields (2, p.5). Land values are not included.

The cost of refuse disposal depends on several factors including:

- Percentage of coarse and fine refuse particle sizes
- Distance from plant to disposal site
- Topography and land availability
- Environmental controls required
- Mode of transportation (truck, tramway or slurry pipeline).

The technology exists for utilizing reject materials to recover sulfur values and generate energy. Several process cost and engineering studies have been conducted that exhibited the economic and technical feasibility of coal-pyrite systems including a refuse-combustion/sulfur-oxides-removal process and a fluid-bed roasting process (33-35). Factors such as market prices and demands for sulfur and sulfuric acid, cost of raw coal, and transportation costs have a significant influence on the economic feasibility of refuse utilization. A cost evaluation summary conducted in 1968 is shown in Table 3-10. The commercial implementation of refuse utilization technology is dependent on local and regional market and site specific engineering factors.

Table 3-8. Coal Preparation Cost Estimates by Process Component (\$1968)

<u>Component</u>	<u>Labor</u>	<u>Dollars Per Ton Supplies</u>	<u>Total</u>
Raw Coal Handling	0.012	0.007	0.019
Coarse Coal Cleaning	0.012	0.016	0.028
Fine Coal Cleaning	0.012	0.012	0.024
Fine Coal Mechanical Dewatering	0.005	0.012	0.017
Fine Coal Thermal Drying	0.012	0.017	0.029
Water Clarification	0.012	0.009	0.021
Rail Car Loading	0.050	0.015	0.065
Refuse Handling	0.015	0.010	0.025
Miscellaneous	<u>0.020</u>	<u>0.012</u>	<u>0.032</u>
Total Labor and Supplies	0.150	0.110	0.260
Power			<u>0.040</u>
Subtotal			0.300
Depreciation			<u>0.200</u>
Total Cost			0.500

Source: Reference 16, p. 5-15.

Table 3-9. Cost Estimates for Physical Coal Cleaning
(Mid-1973, 4000 hrs/year)

<u>Item</u>	<u>Quantity</u>	
Coal Input (tph)	500	1,500
Clean Coal (tph)	429	1,287
<u>Capital (\$10³)</u>		
Bare Cost ^a	6,025	13,583
Engineering	301	679
Fee	<u>603</u>	<u>1,358</u>
Subtotal	6,929	15,620
Contingency (10%)	<u>693</u>	<u>1,562</u>
Total Direct Cost	7,622	17,182
Interest During Construction	1,286	2,899
Startup	4,227	12,515
Working Capital	<u>4,227</u>	<u>12,515</u>
Total Capital Requirement	17,362	45,111
<u>Annual Cost (\$10³/yr)</u>		
Direct Labor ^b	120	200
Maintenance ^c	381	859
Supervision	43	87
Overhead	199	399
Taxes and Insurance	206	464
Electricity ^d	119	358
Lime (1.4¢/lb.) ^e	10	31
Magnetite (2¢/lb.) ^e	13	40

Table 3-9 (Cont'd.)

<u>Annual Cost (Cont'd.)</u>	<u>Quantity</u>	
Frothing Agent (22¢/lb) ^e	14	42
Flocculant (3¢/lb) ^e	31	92
Water (2¢/1000 gal) ^e	<u>1</u>	<u>2</u>
Total Direct Cost	1,137	2,574
Depreciation	657	1,630
Return on Investment	1,133	3,025
Federal Income Tax	<u>374</u>	<u>998</u>
Total Annual Cost (exclusive of coal)	3,301	8,227
\$/ton Clean Coal	1.92	1.60
¢/10 ⁶ Btu Clean Coal ^f	7.68	6.39
10 ¹² Btu/yr Clean Coal	42.9	128.7

^a1973 Total Bare Cost = 60,630 (tph)^{0.74}.

^b6 man/shift for 500 tph, 10 men/shift for 1500 tph.

^c5% per year of total direct capital cost.

^d1¢ per Kw/hr, 4000 HP for 500 tph.

^ematerials consumption:

Lime	2.6	lb/ton dry solids
Magentite	0.5	lb/ton coal treated by dense media
Frothing Agent	0.17	lb/ton coal treated by froth flotation
Flocculant	3.6	lb/ton dry solids
Water	17	gal/ton clean coal

materials balance:

ton clean coal/ton coal input = 0.858

ton dry solids/ton clean coal = 0.165

ton coal by dense medium/ton clean coal = 0.783

ton coal by froth flotation/ton clean coal = 0.217

ton coal dried/ton clean coal = 0.662

Heat required for dryer = 230 Btu/lb coal dried

^fclean coal heating value is 12,500 Btu/lb.

Source: Battelle, reference 63, Table 13, p. 76.

Table 3-10. Refuse Utilization Cost Evaluation Summary (10^3 - 1968)

	<u>Process Description</u>				
	<u>Combustion SO₂ Removal</u>	<u>Fluidized Bed</u>	<u>Outokumpu Process</u>	<u>Carbonization- Desulfurization</u>	<u>Solvent Extraction</u>
Capital Investment, \$	8,300	2,400	5,000	14,000	19,500
Total Annual Cost, \$/year	2,201	1,077	1,695	4,006	7,420
Credits for Products (FOB Plant) \$/year	1,160	826	867	2,432	4,368
Credits for Fuel Value, \$/year	1,230	36	60	-	-
Net Annual Cost, \$/year	-189	215	768	1,574	3,052
Change in Clean Coal Price, \$/ton (FOB Plant)	-0.10	+0.12	+0.41	+0.84	+1.63
Cost of Transportation to markets, \$/year	1,275	568	418	1,609	1,407

Source: Bechtel, reference 53.

3.2 CHEMICAL COAL BENEFICIATION

The chemical cleaning of coal is generally based on the solubility and oxidation properties of coal and its impurities. Coal may be dissolved in a solvent at a specified temperature and pressure to produce a solvent-refined coal. Coal may also be treated chemically by the selective oxidation of pyritic sulfur to produce water soluble sulfur compounds or by using aqueous leaching methods (10). General coal refining technologies are not discussed in this report. These including gasification and liquefaction technologies which enjoy an extensive literature (e.g. 7-13).

Solvent Refining

The solvent refining of coal removes sulfur and ash by the use of hydrogen in a reaction system at elevated temperature and pressure. The solvent refined coal (SRC) product is usually ash free and contains about 40 percent of the original organic sulfur and trace amounts of pyritic sulfur (45). Product yields for current plants using U.S. coals range from 85 to 95 percent energy recovery with about 50 to 70 percent in the form of SRC (43).

History and Background. Solvent coal processing was first practiced on an industrial scale by Pott and Broche in Germany during the 1930's. Under specified conditions of temperature and pressure (14, p. 3-89) their solvent-refined coal contained less than 0.05 percent ash. In one plant, which was capable of processing about 5 tons per hour, the yield of dry ash free coal averaged 78 to 84 percent. Development of the solvent refining process was continued in Germany by Uhde who was able to increase SRC yields to about 90% (43, p. 13). Several processes employing the same general principles as the Pott-Broche process have been developed in several other countries, most notable Japan.

Solvent refining of coal was not seriously studied in the United States until the early 1960's. The Spencer Chemical Division of Gulf Oil Corporation, contracting with the Office of Coal Research, concluded that ash can successfully be removed from coal using a process in which:

- The coal is dissolved in the presence of hydrogen in a solvent derived from the coal itself
- The coal solution is filtered to remove the undissolved mineral matter
- The solvent is removed for recycle and the de-ashed product recovered.

Sulfur removal was not specifically evaluated as the purpose of the Spencer study was to study ash reduction (44). However, some sulfur reduction was noted as shown in Table 3-11. Most of the sulfur was liberated as hydrogen sulfide gas. The heating value of the coal exceeded 15,550 Btu/lb while feed coals ranged from 11,000-12,000 Btu/lb. Work on Kentucky coal was conducted at a scale of one ton per day.

Current SRC research and development includes the operation of two large pilot plants. A 6 ton per day facility began operations in 1973 at Wilsonville, Alabama and a 50 ton per day plant started SRC testing in 1974 at Fort Lewis, near Tacoma, Washington (43,51). Future developments for solvent refining include an interest in building a 900 ton per day demonstration plant (46). A full-scale commercial facility could produce 2,000 (43) to 20,000 (46,47,51) tons per day of clean solid fuel.

Solvent Refining Process. In the SRC process, raw coal is pulverized and mixed with a coal-derived solvent at about 100° F. The slurry is pumped to a preheater, which raises the temperature to about 800° F, and then into a reaction vessel or dissolver. The dissolver is operated at a temperature of between 800° F and 900° F and at a pressure of 1000 psig. At these conditions about 95% of the coal is dissolved.

The flow from the dissolver, which contains dissolved coal and insoluble inorganics, passes into a high-pressure separator where gases are removed. The liquid stream is then flashed to about 150 psig, creating two phases. The vapor stream is removed and distilled to recover light organic chemicals. The liquid stream is filtered producing an ash-sulfur cake and a cleaned liquid, and then the solvent is then recovered by distillation and the heavy residual liquid is cooled to form a solid SRC product.

SRC yields are a function of operating severity, i.e., they diminish with increased temperature and pressure. As more sulfur and ash are removed, higher levels of light liquids, solvent and gases are created at the expense of the solid SRC. Process difficulties have included the accumulation of solids in the reactor (dissolver) section, problems in recovering solvent from the filter cake, and high solvent ratios and feed pump problems for Wyoming coals in particular (43, p. 14). Process trends include the possible use of hydrocycloning instead of filtering to remove inorganic solids (46), or the use of solvent precipitation to help reduce the relatively high filtration costs. Magnetic removal of iron sulfide is another process refinement.

that may be useful as a partial solids separation technique, however, tests are only now being planned (43, p. 15).

A related development is the discovery that carbon monoxide and steam are more effective than hydrogen alone for processing some coals (45, p. 5). This result suggests that synthesis gas could be used in place of hydrogen in the SRC process, so that a combination gasification/ solvent refining system may be more economic.

Table 3-11. Sulfur Reduction of Selected U.S. Coals Using the "Spencer" Process

<u>Coal Source</u>	<u>Sulfur Content Feed Coal (%)</u>	<u>Sulfur Content Product Coal (%)</u>	<u>Sulfur Reduction (%)</u>
Kentucky	3.50	1.23	65
Wyoming	0.85	0.41	52
Kansas	3.26	0.68	79
New Mexico	0.61	0.40	34

Source: Spencer Chemical Division of Gulf Oil Corporation, reference 44, p. 192.

Solvent Refined Coal Characteristics. Early studies of solvent refining of U.S. coals by the Spencer Chemical Division are shown in Table 3-11. Related ash reduction achieved levels less than 0.05 percent, while the SRC energy content was greater than 15,500 Btu/lb.

Recent SRC operations at Wilsonville are described in Table 3-12 (43). The SRC product has a heating value of about 16,000 Btu per pound (45), and has a surprisingly uniform sulfur content regardless of feed coal characteristics. The ash content of SRC is usually less than 0.15 percent by weight (47,51).

The sulfur and ash content of SRC may be low enough so that air quality regulations are satisfied if it is burned in a conventional boiler. However, sulfur reduction is limited by the amount of organic sulfur remaining in the SRC product.

Environmental Factors. Environmental considerations for the construction and operation of a commercial-sized SRC facility will primarily involve air and water pollution impacts (48).

Air Pollution. Contamination of the air may present the greatest pollution hazard. Sulfur dioxide and hydrogen sulfide may be emitted in the tail gases or in the exhaust gases from burners and heaters. Particulates could be released in the form of fugitive dust associated with coal handling and pulverizing. Hydrocarbons, nitrogen oxides and carbon monoxide may also be generated from combustion and other processes.

Water Pollution. Waste water from the SRC process can result from inherent moisture in the feed coal, decomposition water and water introduced as a result of byproduct recovery. Each percent of moisture in the feed coal is equivalent to about 2.4 gallons of water per ton of coal. This can result in 10 to 12 gallons per ton of water for a 4 to 5 percent moisture coal. In addition, the carbonization of dry coal produces water of decomposition at a rate of about 9 to 10 gallons per ton. Thus not considering water needed for byproduct recovery, waste water may amount to over 20 gallons per ton of raw coal. This water will have a high total dissolved solids composition and thus may present water treatment difficulties.

SRC Advantages and Limitations. Advantages of solvent refining process include:

- The SRC facility is decoupled from the power plant so that its load-duration characteristics are relatively independent. It may be economic to operate the SRC facility when the power plant is not operating, i.e. an inventory of clean fuel may be maintained. This is an advantage of all coal preparation methods.
- A SRC plant may provide fuel for more than one power plant so that an advantage may be made of any economies of scale.
- The SRC product may be low enough in sulfur and ash content so that other residual control technology such as flue gas desulfurization

Table 3-12. Wilsonville SRC Operations

Coal Source	Kentucky	Pennsylvania	Illinois	Illinois	Wyoming
State Mine Seam	Colonial 9 and 14	Loveridge Pittsburgh 8	Burning Star 6	Monterey 6	Belle Ayr R. Smith
Feed Coal					
Sulfur Content (%)	3.1	2.6	3.1	4.4	0.7
Feed Rate (lb/hr/ft ³ reactor)	25-50	25	23	25	20
Coal Conversion (%)	91-95	91	90	95	85
SRC Output					
Yield (%)	55-65	69	63	54	47
Sulfur Content (%)	0.8	0.9	0.9	0.95	0.1

Source: EPRI, reference 43.

or electrostatic precipitation may not be required to meet air quality regulations.

- SRC is a relatively uniform product which will reduce power plant design requirements and thus lower electric generating costs. Grinding and pulverizing costs at the power plant may also be reduced.
- SRC may be produced in a hot liquid form so that transportation may be by pipeline, especially for adjacent SRC/power plant facilities. This eliminates coal handling and pulverizing at the power plant.

Disadvantages of the solvent refining process include:

- The SRC process only produces about 50 to 70 percent of its output in the form of solid or liquid boiler fuel, although 90 percent of the energy in the raw coal is usually recovered. This requires that markets be obtained for the light liquid products at feasible market prices.
- The cost of SRC production is likely greater than the cost of flue gas desulfurization at the present time, except possibly for use as a peaking fuel (47).
- Nitrogen is not removed by solvent refining so that the percent nitrogen increases for SRC as compared to the raw feed. This may have implications for meeting NO_x air quality standards.

SRC Cost Estimates. The most definitive published cost estimate to date has been for the SRC process developed by Pittsburgh and Midway Coal Mining Company, in cooperation with subcontractors, for the Office of Coal Research, U.S. Department of the Interior (now a part of ERDA) (49). This cost evaluation was for a 10,000 ton per day (raw coal) solvent refining plant to feed a mine-mouth power plant with both solid or liquid fuels. An overall material balance for this design is shown in Table 3-13. The primary cost factors include capital, operation, maintenance, byproduct credits and power plant cost savings (49,64).

Capital cost estimates for the case without coking (other cases included 10% and 25% coking) to produce a solid fuel are shown in Table 3-14. To produce a hot liquid fuel, the cost for solidification and storage should be deducted, and the cost of \$150,000 (\$1969) for liquid storage should be added. Therefore, the total capital cost for producing a liquid fuel product has been estimated to be about \$71.4 million (\$1969), or about \$300 per ton per hour.

Operating and maintenance costs are shown in Table 3-15 for the case without coking, for the production of either a solid or liquid fuel. Designing the process to produce a liquid fuel generally increases operating and maintenance costs due to greater utility requirements.

Table 3-13. Material Balance for a 10,000 tpd SRC Plant - without coking (lb/hr)

Feed

Coal*	833,333
Hydrogen	10,895
	<u>844,228</u>

Yields

Fuel Gas (24,570 Btu/lb)	96,375
Sulfur	20,460
Light Oil	44,351
Cresylic Acids (includes 3000 lb Phenol)	13,000
De-ashed Coal Product**	488,376
Decarbonized Mineral Residue (ash)	60,110
Water	91,667
Losses (CO ₂ , SO ₂ , etc.)	29,999
Total	<u>844,228</u>

*3% moisture, 7.13% ash, 3.38% sulfur, 12,821 Btu/lb

**15,900 Btu/lb, 1% sulfur.

Source: Pittsburgh and Midway Coal Mining Company, reference 49, p. 5-2 and 5-16.

Table 3-14. Capital Cost Summary for a 10,000 tpd SRC Plant - Without Coking (\$1969)

<u>Component</u>	<u>Capital Cost</u>
Coal Handling and Preparation	6.04x10 ⁶
Preheaters and Dissolvers	16.36
Mineral Separation (Filters)	7.26
Solvent Recovery	7.82
Gas Recovery	0.37
Mineral Residue Processing and Storage	2.10
Coking	--
Product Solidification and Storage	3.87
Power Generation	11.90
Cooling Water System	1.97
Waste Water Treatment	1.37
Tank Farm	0.36
Hydrogen Generation Plant	6.30
Sulfur Plant	4.50
Acid Gas Removal Unit	2.29
Phenol and Cresylic Acid Recovery Unit	0.75
Instrument and Service Air	0.11
Support Buildings	1.38
Site Preparation	0.36
Total	\$75.11x10 ⁶

Source: PAMCO, reference 49.

Table 3-15. Operation and Maintenance Cost Summary for a 10,000 tpd SRC Plant - Without Coking (\$106 - 1966)

<u>Item</u>	<u>Solid Fuel</u>		<u>Liquid Fuel</u>	
	<u>Data</u>	<u>Cost</u>	<u>Data</u>	<u>Cost</u>
Operating Labor (\$4/hr)	155 men	1.29	139 men	1.16
Maintenance Labor	-	1.06	-	1.01
Maintenance Material	-	1.60	-	1.51
Management and Supervisory	15% of Labor	0.35	15% of Labor	0.32
Indirect Labor	15% of Labor	0.35	15% of Labor	0.32
Payroll Overhead	45% of Payroll	1.38	45% of Payroll	1.27
Tax and Insurance	1.5% of Capital	1.13	1.5% of Capital	1.07
Fuel (26.9¢/10 ⁶ Btu)	771x10 ⁶ Btu/hr	1.66	1548x10 ⁶ Btu/hr	3.33
Water (10¢/M Gal)	2900 GPM	0.14	2900 GPM	0.14
Catalyst, Chemicals	-	0.24	-	0.24
Interest on Working Capital (\$5,000,000)	7 1/2%	0.38	7 1/2%	0.38
Total		9.58		10.75

Source: PAMCO, reference 49.

Byproduct credits are significant economic factors for the operation of a SRC plant. These credits for the case without coking, and for the production of either a solid or liquid fuel, are shown in Table 3-16. Data have been estimated for other types of coal (10, p. 24-30) in \$1973 using an exponential power factor of 0.7 and the CE plant cost index (50). A summary of this data is shown in Table 3-17.

Other more recent but less detailed cost estimates have appeared in the literature including:

- Commercial SRC plant: \$75 million investment (\$1973), 10,000 tpd (3.3 million tpy), 5,600 tpd SRC, 240 employees (52).
- Commercial SRC plant: \$200 million investment, 20,000 tpd (46).
- Commercial SRC plant: \$400-500 million investment (late \$1974), 20,000 tpd (51).
- Commercial SRC plant: \$467.6 million investment (\$1975), 20,000 tpd, \$19.91 - \$22.40 per ton SRC, \$0.62 - \$0.70 per million Btu SRC (47).

The total cost of an SRC facility depends on its intended purpose. The facility may be designed and operated to produce significant byproducts at the expense of SRC, if market economics are justified. The additional cost of refining a coal depends on the amount of hydrogen consumed. Gasification and liquifaction processes require the highest degree of hydrogenation. The coal refining process and the quality of the coal should be tailored to meet environmental requirements of a specific area. Technical and economic tradeoff analyses should be conducted to optimize plant subcomponent design in the context of local market and environmental considerations.

Power Plant Cost Factors. The use of solvent refined coal may reduce the capital and operating costs of burning fuel and controlling emissions for utility boilers. These savings may result from elimination of coal handling and pulverization equipment (when using a liquid SRC fuel), ash handling and disposal equipment, soot blowers, fly ash precipitator or other particulate collection systems, flue gas desulfurization and sludge disposal equipment. Also, some maintenance costs will be reduced and the overall thermal efficiency will increase as a result of lower stack gas temperature.

A conceptual design and cost estimating study has been conducted for the differences in utility boilers when using a high sulfur Illinois coal vs. a liquid SRC product (49, Appendix B). A summary of the results of this study indicated a net savings of about 0.36 mills/Kwh (\$1970)

Table 3-16. Byproduct Credit Summary for a 10,000 tpd SRC Plant -
Without Coking (\$1969)

<u>Byproduct</u>	<u>Lbs/hr</u>	<u>Bbl/day</u>	<u>Solid Fuel</u>	<u>Unit Price</u>	<u>Annual Total</u>
			<u>Tons/day</u>		
Light Liquid	44,351	3,885	-	\$3.50/Bbl	4.54x10 ⁶
Sulfur	20,800	-	232.2	\$35/ton	2.60
Phenol	-	-	-	8¢/lb	-
Cresylic Acids	13,000	-	156	4¢/lb	4.16
CO ₂	60,390	-	725	\$6/ton	1.45
Electrical Power		32,390 Kwh/hour	0.5¢/Kwh		1.30
Total					\$14.05x10 ⁶

Table 3-16 (cont.)

<u>Byproducts</u>	<u>Lbs/hr</u>	<u>Bbl/day</u>	<u>Liquid Fuel</u>	<u>Unit Price</u>	<u>Annual Total</u>
			<u>Tons/day</u>		
Light Liquid	77,624	6,800	-	\$3.50/Bbl	\$7.94x10 ⁶
Sulfur	20,800	-	223.2	\$35/ton	2.60
Phenol	3,000	-	36	8¢/lb	1.92
Cresylic Acids	10,000	-	120	4¢/lb	3.20
CO ₂	8,330	-	100	\$6/ton	0.20
Electrical Power		26,690 Kwh/hour	0.5¢/Kwh		1.07
Total					\$16.93x10 ⁶

Source: PAMCO, reference 49.

Table 3-17. Summary Cost Estimates for Solvent Refining of Five U.S. Coals (Mid-1973, 8000 hrs/year)

Item	Eastern Medium S	Eastern High S	Central Medium S	Central High S	Western Subbituminous ^a
Product Rate, tpd	7,236	7,236	7,236	7,236	7,834
Coal Input Rate, tpd	11,993	12,664	13,765	14,391	13,600
Coal Characteristics Sulfur ^d	1.02%	2.37%	1.05%	2.41%	0.45%
Direct Capital Cost (\$10 ⁶)	105.45 ^b	118.05 ^b	115.58 ^b	128.55 ^b	120.26 ^c
Indirect Capital Cost (\$10 ⁶) ^e	<u>77.80</u>	<u>85.82</u>	<u>85.84</u>	<u>94.00</u>	<u>88.32</u>
Total Capital Requirement (\$10 ⁶)	183.25	203.87	201.42	222.55	208.58
Operation and Maintenance (\$10 ⁶ /yr) ^f	15.60	17.32	16.68	18.51	17.56
Byproduct Credit (\$10 ⁶ /yr) ^g	(4.92)	(6.03)	(5.68)	(6.90)	(6.13)
Fixed Costs (\$10 ⁶ /yr) ^h	<u>22.16</u>	<u>24.63</u>	<u>24.35</u>	<u>26.90</u>	<u>25.22</u>
Total Annual Cost (\$10 ⁶ /yr)	32.84	35.92	35.35	38.51	36.65
Product Cost (\$/ton SRC)	13.62	14.89	14.66	15.97	14.03
Product Cost (\$/10 ⁶ Btu SRC) ⁱ	0.43	0.47	0.46	0.50	0.44
Heat Output Rate (10 ¹² Btu/hr SRC) ⁱ	76.70	76.70	76.70	76.70	83.00

^a

As indicated in Reference 10, Table 3, p. 26.

^b

Direct cost based on Battelle Energy Program report "Liquifaction and Chemical Refining of Coal," July, 1974 (Reference 10). Sulfur recovery section costs based on Shore, et al., EPA 650/2-74-098, September, 1973.

^c

Direct cost based on Shore, et al.

^d

As estimated from Reference 10, Table 3, p. 26.

^e

Indirect capital costs include engineering, fees, contingency, interest during construction, startup and working capital.

^f

Operating labor = 175 men. All data based on Reference 10.

^g

Credits include: Phenol at 1¢/lb, cresylic acids at 0.5¢/lb, power at 0.6¢/Kwh and 0.5 Kwh per pound of ash burned.

^h

Fixed costs include depreciation, return on investment and federal income tax.

ⁱ

Based on 15,000 Btu/lb SRC.

in the total annual operating cost of electric power generation with an 800 Mw facility; summary data is shown in Table 3-18. A more recent summary (47), shown in Table 3-19, shows that the cost savings are dependent on operating factor. For a 500 Mw plant operating at 5000 hours per year, the cost savings may be about 1.2 mills/Kwh (\$1975). Cost savings can become rather significant for the use of SRC in peaking power plants. Cost savings using a solid SRC product were not estimated; However, coal handling and pulverizing equipment would be required, which would reduce any potential savings.

The least-cost SRC/power plant configuration would be for a new mine-mouth design using a liquid product. Savings for existing power plants would not include capital-related items (unless retrofitting or other modifications were required) nor fixed operating expenses.

Aqueous Leaching Processes

In addition to solvent refining, coal may be beneficiated by leaching and selective oxidation of its mineral impurities to produce solvent soluble constituents. These processes remove nearly all of the pyritic sulfur, and some of the organic sulfur, however, much of the ash material is not removed.

History and Background. The use of selective oxidation and chemical leaching methods in the coal industry is relatively new; chemical methods with commercial potential were not developed in the U.S. until the late 1960's and early 1970's.

One of the earliest of these was invented at TRW by R. A. Meyers (53). Known as the "Meyers Process," the method is capable of the removal of 40 to 80% total sulfur plus 10 to 40% of the coal ash. It also increases the energy content by about 5 percent (54). The Meyers technique uses a ferric sulfate solution to leach pyritic sulfur which is converted to its elemental form and later extracted in a solvent. A related chemical leaching process has been developed at the Ledgemont Laboratory of the Kennecott Copper Corporation (57). The Ledgemont process uses oxygen leaching prior to washing with water. Battelle Memorial Institute has recently announced a hydrothermal version which removes sulfur from coal by leaching with a strong alkaline solution (58, 59). Processes have also been developed by the Bureau of Mines and Southern Research Institute, General Electric, Institute of Gas Technology and Atlantic Richfield (10,28). Many of these processes have been adapted from existing technologies used in the copper and steel industries.

Meyers Process. Crushed coal is treated with a warm ferric sulfate solution at atmospheric pressure which oxidizes pyritic sulfur to its elemental form. The ferric sulfate solution is regenerated and the treated coal is washed with water to remove the residual leach solution. Sulfur is then extracted in an organic solvent and the cleaned coal is dried. Typical inputs, outputs and utility requirements of the Meyers process are shown in Tables 3-20 and 3-21.

Table 3-18. Summary of Power Generation Costs when Using High-Sulfur Illinois Coal vs. A Liquid SRC - 800 Mw (\$1970)

Coal Characteristics	Illinois	SRC
Sulfur (%)	3.38	0.78
Moisture (%)	2.70	0.00
Ash (%)	7.13	0.10
Btu/lb	12,821	15,682
Power Plant Capital Cost		
Investment (\$10 ⁶)	140.0	130.7
\$/Kw	175.0	163.3
Annual Fixed Cost (14%)	19.6	18.3
Operation and Maintenance Cost (\$10 ⁶ /year)	3.2	2.8
Total Annual Operating Cost		
\$10 ⁶ /year	22.8	21.1
mills/Kwh (exclusive of fuel)	4.26	3.90
Net Annual Savings (mills/Kwh)		0.36

Source: Stearns-Roger Company, reference 49, Appendix B.

Table 3-19. Power Generation and Emission Control Savings Using Liquid Solvent Refined Coal in New 500 Mw Utility Boilers*
(\$1975)

Capital Savings	<u>\$106</u>
Boiler	5.0
Electrostatic Precipitator	4.1
Soot and Ash Handling	0.4
Coal Handling	3.7
Stack	2.5
Electrical Equipment	<u>0.6</u>
Total Capital Savings	16.3
Annual Capital Savings (15%)	2.4
Operation and Maintenance Savings (5000 hr/yr)	
Labor	0.25
Electricity	0.75
Maintenance	<u>0.25</u>
Total Annual Savings	3.65
	mills/Kwh
7000 hr/yr	0.99
5000 hr/yr	1.22
3500 hr/yr	1.68
1500 hr/yr	3.05

*Data adapted from reference 47, p. 17.

Table 3-20. Typical Inputs and Outputs of the Meyers Process

	Input (lb/hr)	Output (lb/hr)
Coal	220,000	210,318 ^a
Air		
To Process	31,556	
To Boiler	141,229	
To Cooling Tower	12,700,000	
From Cooling Tower		12,700,000
Solvent	200	-
Water	153,850	135,560 ^b
Flue Gas	-	154,570
Sulfur	-	2,438
Iron Sulfates	-	16,258
Nitrogen	-	24,050
Ash	-	2,541
Vents	-	1,100

^aIncludes Moisture

^bFrom cooling tower

Source: Exxon Research and Engineering Co., reference 62.

Table 3-21. Utility Requirements of the Meyers Process

Steam, lb/hr	120,000 ^a
Electricity, Kw	4,530
Fuel, lb/hr	13,234
Water, lb/hr	
Raw Water	153,850
Boiler Feed Makeup	6,000
Cooling Water Makeup	135,560
Cooling Tower Drift Loss	14,160
Cooling Tower Blowdown	21,400

^aHigh pressure steam.

Source: Exxon Research and Engineering Co., reference 62.

An 8 tpd test facility is being completed which will compare the results using coarse and fine coals with leaching, filtration and washing process refinements (56). The process is apparently applicable with all U.S. coals. Typical analysis of raw coal feed and chemically desulfurized product are shown in Table 3-22, maximum pyritic sulfur removal has been about 97 percent (60, 61). Additional information regarding the background, process description and program status may be obtained from recently published reports (28).

Ledgemont Process. Crushed coal is mixed with water and is either physically cleaned or fed to a leaching reactor where oxygen is inserted at specified temperatures and pressures. The pyritic sulfur is oxidized to soluble sulfates and then separated by washing with water. The solution is neutralized using lime or limestone and the iron compounds and gypsum are separated and disposed. No elemental sulfur is formed and the leach solution does not require regeneration. The process is apparently faster than ferric sulfate leaching although it requires sludge disposal. Typical results using this process indicated that over 99 percent of the pyritic sulfur is removed (57).

Table 3-22. Typical Analysis of Raw Coal and Chemically Desulfurized Coal Using the Meyers Process

<u>Mine/State</u>	<u>Sulfur (%)</u>		<u>Ash (%)</u>		<u>Btu/lb</u>	
	<u>Raw</u>	<u>Treated</u>	<u>Raw</u>	<u>Treated</u>	<u>Raw</u>	<u>Treated</u>
Delmont/Pa	4.9	1.0	27.18	20.44	11,012	12,108
Bird No. 2/PA	3.1	0.8	30.32	24.17	10,551	11,500
North River/Ala	2.1	0.9	49.28	42.84	7,693	8,323
Martinka/WVa	2.0	0.6	49.25	43.46	7,552	8,138
Lucas/Pa	1.8	0.6	8.68	6.32	13,451	13,884
Marion/Pa	1.4	0.7	26.40	22.61	11,046	11,720

Source: TRW, reference 56.

Battelle Hydrothermal Process. Crushed coal is mixed with chemical lechant and then pumped to an autoclave where it is heated at specified temperatures and pressures. Sodium hydroxide and calcium hydroxide are the most promising lechant materials found thus far. After the hydrothermal treatment, the slurry is filtered and dried, while the lechant is recovered and reused.

This process has the advantage of being able to remove a significant fraction of organic sulfur, unlike the processes mentioned above. Solvent refining and gasification/liquefaction processes remove organic sulfur, however, they may be more expensive. An additional treatment step, rinsing the coal with a dilute acid, would make it possible to extract most of the coal ash. Heavy metals are also removed in the Battelle process. In addition, the solid fuel is impregnated with "sulfurgetting" alkali chemical that reacts with the remaining sulfur to produce nonvolatile sulfur compounds which remain with the bottom ash. Typical results using this method are shown in Table 3-23.

Aqueous Leaching Processes, Advantages and Limitations. These processes primarily desulfurize coal. Nearly all of the pyrite sulfur is removed, while for the Battelle process, as much as 70 percent of the organic sulfur is also extracted. Like other coal preparation systems, these methods are also decoupled from the power plant which has the advantage of independent operation. Under certain conditions, especially for the Battelle process, these methods may produce a product that meets sulfur emission regulations when burned directly. The yield of cleaned coal for boiler fuel is greater than that with SRC processes. The major disadvantage of these systems is that a significant amount of ash remains in the coal.

Process Cost Estimates. Early cost estimates for the Meyers Process are shown in Table 3-24. A summary of cost estimates circa 1974 is shown in Table 3-25 for chemical cleaning of high sulfur Eastern Coal. More recent capital cost estimates include:

- Meyers Process: \$368,100/tph capital investment (\$1975), 8,000 tpd (57)
- Ledgemont Process: \$284,000/tph capital investment (\$1975), 8,000 tpd (57)
- Battelle Process: \$110 million capital investment (\$1975), 10,000 tpd (58).

Published data for these processes is not generally available as their utility-scale application is still under research and development.

Table 3-23. Typical Analysis of Raw Coal and Chemically Beneficiated Coal Using the Battelle Hydrothermal Process

<u>Mine/State</u>	<u>Pyritic Sulfur (%)</u>		<u>Removal (%)</u>
	<u>Raw</u>	<u>Treated</u>	
CN719/Ohio	4.0	0.1	99
Belmont/Ohio	1.6	0.1	92
NE41/Ohio	4.0	0.1	99
Ken/Ky	2.1	0.2	92
Beach Bottom/Pa	1.7	0.1	95
Eagle 1/Ill	1.5	0.2	87
	<u>Organic Sulfur (%)</u>		<u>Removal (%)</u>
	<u>Raw</u>	<u>Treated</u>	
Sunny Hill/Ohio	1.1	0.6	41
Martinka 1/WVa	0.7	0.5	24
Montour 4/Pa	1.0	0.3	72
Westland/Pa	0.8	0.5	38
Beach Bottom/WVa	1.0	0.7	30
Mergs 1/Ohio	2.3	1.1	52
<u>Source: Battelle, reference 59.</u>			

Table 3-24. Cost Estimates for the Meyers Process - 100 tph, 0.8 Million typ (feed) (\$10³-1972)

Coal Characteristics	<u>Input</u>	<u>Type A</u>	<u>Output</u>	<u>Input</u>	<u>Type B</u>	<u>Output</u>
Btu/lb	12,300		12,900	13,600		14,300
Pyritic Sulfur	3.2%		0.16%	0.8%		0.23%
Ash	20%		14%	-		-
Total Direct Capital Cost		7,460			4,150	
Annual Cost						
Depreciation (10% straight line)		746			415	
Maintenance, insurance, taxes, interest		746			415	
Labor (3.3 positions - 3.0 positions)		330			300	
Utilities						
Electricity (10 ³ Kw, 5 mill/Kwh)		40	(750Kw)		30	
Cooling Water (2000 gpm, 2¢/10 ³ gal)		10			10	
Heating - 130x10 ³ Btu/hr; coal, 5 tph		-			-	
Boiler feed water		-			-	
Materials						
Oxygen 99.5%, 3.8 tph (\$10/ton)		304	(1.0 tph, \$12/ton)		96	
Solvent 200 lb/hr (3¢/lb)		48			48	
Total Annual Cost		2,224			1,314	
\$/ton Clean Coal		3.09			1.75	
Coal Yield (weight basis)		90%			94%	
Coal Yield (Btu basis)		95%			95%	

Source: TRW, reference 3.2-65, p. 128-134.

Table 3-25. Cost Summary for Chemical Beneficiation of High Sulfur Eastern Coal^a

Process	Capital Cost \$10 ⁶	Operating Cost ^b ¢/10 ⁶ Btu
Selective Oxidation	10 ± 5	3 ± 2
Meyers Process	47 ± 9	12 ± 3
Solvent Refining	110 ± 28	15 ± 8

Source: Battelle, reference 10, p. 5.

^aStandard heat output of 9.6×10^9 Btu/hr

^bExcludes capital and fuel

CHAPTER 3

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CHAPTER 4

COAL TRANSPORTATION TECHNOLOGY

Historically, three major modes have carried U.S. coal: rail, waterway and truck. The slurry pipeline has been used to transport coal and other mined ores and may represent a major future mode of U.S. coal transportation. In this short section, coal transportation technology is briefly discussed, including a summary of comparative cost estimates by each mode. Transportation may account for as much as 50 percent of the cost of delivered coal, so that it may significantly influence the nature of an economic tradeoff between providing for electric power while controlling residual emissions.

4.1. RAIL TRANSPORT

Coal transport makes up about 15 percent of total rail revenue ton-miles, and in 1974 about 75 percent of all the coal moved by rail (1). The average U.S. rail haul of coal in 1972 was 283 miles, indicating that most of the coal was produced and consumed locally. Coal moves by rail primarily in open hopper cars, with a trend toward a 100 ton standard car.

The most efficient movement of coal is by unit train, which is a dedicated shipment of up to about 100 cars, or approximately 10,000 tons from a mine directly to a utility or other major user. In 1975, unit trains carried about 25% of all coal mined (3). Unit trains take advantage of economies of scale and distance so that overall costs may be reduced. In addition, long-term contracts may be negotiated, crew sizes reduced and turn around times minimized, in contrast to conventional rail shipments. In many unit train operations, the cars never need to be uncoupled and the train never stop, except for service or a change of crew.

The use of unit train transportation of coal is increasing; however, increased investments in loading and unloading facilities will be required. In addition, if western coal is continued to be produced at its current rate (see Chapter 2), track maintenance costs will increase and track capacities may need to be upgraded. This will require significant capital investments.

4.2. WATERWAYS TRANSPORT

The U.S. domestic waterway system consists of over 25,000 miles of channels, lakes and intracoastal routes. In 1970, about 30 percent of the total ton miles of all commodity movements were by domestic water; water transport accounted for 15 percent of all coal shipment (1). In 1974 coal accounted for about 22 percent of the total tonnage flow (4). The average water movement distance for coal is about 480 miles, and the cost of shipment by water may be less than one-half that for rail.

Waterways transport is particularly significant east of the Mississippi River, but is also prominent along the Texas gulf coast and on the Columbia/Snake River System. Open hopper barges are primarily used ranging from 1,000 to 3,000 tons capacity, and a single tow of barges may carry over 30,000 tons; most coal moves in tows of 10 to 14. The average speed is about 6 mph.

Many sections of the inland waterways are in need of improved capacities of locks and dams. Lock sizes determine the size of individual barges and tows, which ultimately sets the waterway capacity. The bottleneck most seriously affecting the long-term movement of coal is the central interchange of inland rivers on the boundary of southern Illinois. Six navigable rivers converge at this point which influences coal transportation for hundreds of miles in all directions.

Coal and grain compete for available barge capacity at critical times of the year (1, p.II-46). At harvest time the competition for barges on the Upper Mississippi is intense and rates for spot service rise to nearly double those for normal service. This may significantly affect coal movements out of the Northern Great Plains. The capacity constraint will in part be reduced by the construction of a large rail-barge transshipment at Duluth, Minnesota so that Great Lake capacity may be increased (4).

4.3. TRUCK TRANSPORT

The most significant movement of coal by truck is from the mine site to the point of loading for transportation by other mode. The 1970 average truck haul of coal was about 67 miles; less than 2 percent of the truck ton-miles were accounted for by coal movements. Very little coal goes over the road all the way from mine to user, and except for very short distances, trucking rates are prohibitively higher than any other mode.

4.4. SLURRY PIPELINE TRANSPORT

Slurry pipelines are currently used throughout the world principally to transport ore from mines to processing plants. Only one coal slurry pipeline is currently operating in the United States, the Black Mesa line in Arizona (5).

The technology for slurry pipelining solids is fairly well established and the ton-mile capacity is increasing rapidly (6). However, there are a variety of environmental issues that are unique to slurry pipelines, most notably water requirements (7). The water issue and a land-use problem of eminent domain are the current subject of much debate and controversy (7,8,12).

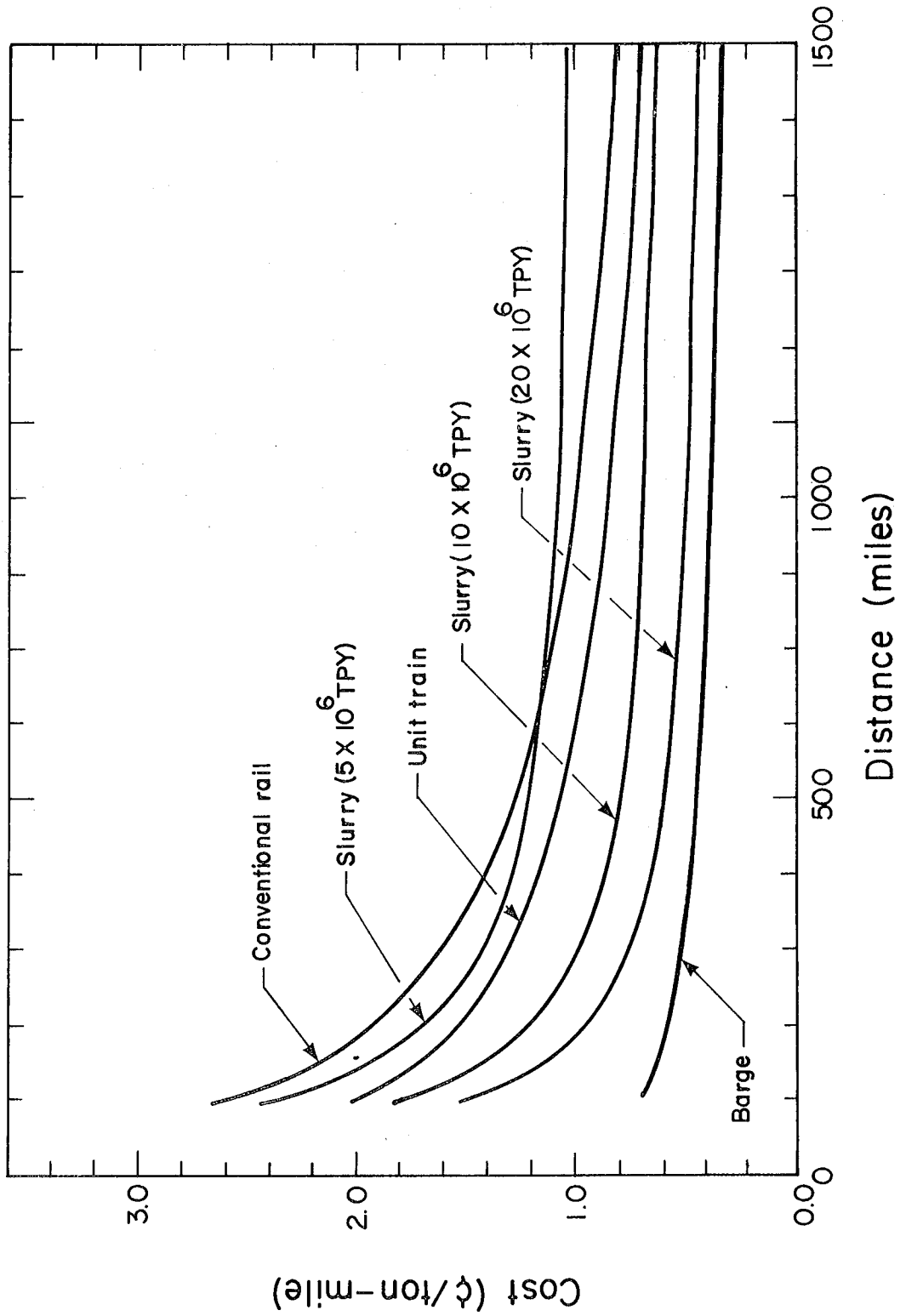
The economics of slurry pipelines appears to be the most favorable for high volume long distant shipments. It is generally agreed that new coal slurry pipelines may have a 2:1 cost advantage over unit trains (2,9,10). However, when compared to the cost of upgrading existing railroad capacity, a new slurry system may be a more costly method of increasing overall transportation capacity (10). In addition, slurry pipelines are capital intensive. This is a two-edged economic sword for two reasons: (1) Due to escalation

effects, the transport rates for an already existing slurry pipeline will not escalate as fast as those for a more operating and maintenance intensive technology; however, the cost of new systems increases faster than that for already established transport modes; (2) because the fixed costs are comparatively high, slurry pipelines enjoy a significant economy of scale with capacity and distance; however, these pipelines must be operated at a relatively high annual operating factor in order to recover the capital investment. Thus if a pipeline is forced to shut down, transport rates may increase significantly. Also if a power plant is shut down, coal storage may require additional cost.

4.5. COAL TRANSPORTATION COSTS

The cost of coal transportation in \$1974 ranged from approximately 0.5¢/ton-mile for long distance barge transport to perhaps 2.0-2.5 ¢/ton-mile for short distance conventional rail hauls. Coal transportation costs have been summarized as displayed in Figure 4-1 (11). This figure shows the 1974 cost of new slurry systems at three capacities, and the estimated rate structure for rail and barge transport, all as a function of distance.

Figure 4-1
COAL TRANSPORTATION COSTS
\$1974



XBL 7711-6980

CHAPTER 4

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CHAPTER 5 COAL-ELECTRIC GENERATION TECHNOLOGY

Electricity provided about 25 percent of the U. S. energy needs in 1972 (1), and coal supplied over 42 percent of this electric power. Historically, coal has been the predominant fuel used to generate electricity. With the advent of inexpensive low-sulfur oil and natural gas, the fraction of coal used remained constant or gradually declined, while oil and gas consumption greatly increased. Currently, coal still provides more energy than any other fuel for the production of electric energy in the U.S. Also, as coal is abundant, it is the only fuel available in sufficient quantities to provide this electric energy for the future.

There are many technologies capable of producing electricity directly from coal including conventional coal-fired boilers, fluidized bed combustors and gasification-combined cycle systems. This section includes a discussion of these technologies, with emphasis on the conventional coal-fired power plant. Electric power will continue to be exclusively produced by this conventional technology for at least the next decade. Fluidized bed and gasification-combined cycle technologies are the subject of intensive research and development efforts, but still have a commercial timetable in the mid-1980's and beyond. Electricity may also be generated from coal-derived fuels such as low-Btu gas, synthetic fuel oil, chemically-refined products, and in the magneto-hydrodynamic-system cycle using coal gasification. These technologies may have even a longer commercial time horizon.

This section contains an overview of the technologies that generate electricity directly from coal, including a short description of each process, a description of the operating characteristics and important parameters, and a summary of cost estimates. Conventional coal-fired power plants are discussed in the most detail, while the generation of electricity from coal-derived fuels is not generally discussed. The effects of physically and chemically treated coal on power plant operations, such as coal beneficiated by washing and solvent refined coal, are discussed in Chapter 2.

5.1. CONVENTIONAL COAL-FIRED POWER PLANTS

The primary technology for electric power generation considered in this section is the conventional coal-fired steam-electric power plant. In this type of facility, coal is burned in a furnace to produce heat; the heat vaporizes water to steam in a boiler; the steam is used to drive a turbine and the turbine drives an alternator, which generates electricity (2).

Coal-Fired Power Plant Types

Three types of coal handling are used in coal-fired generators. First, in the stoker-fired furnace, coal is combusted on a moving grate. This type of facility is generally used with smaller industrial boilers of less than 200,000 Kg steam/hour. Second, in the pulverized coal-fired furnace, coal is ground to pass through a wire mesh. With This type of facility has many advantages over the stoker furnace:

Table 5-1. U.S. Sources of Energy For Generating Electricity, 1972.

Source	Percent
Coal	42.2
Natural Gas	22.1
Petroleum	16.9
Hydroelectric	15.7
Nuclear	3.1
Geothermal	Negligible

Source: BOM and FPC in Reference 2.

larger capacity furnaces may be constructed, there is more flexibility in the type of coal that can be burned, oil and gas may be burned with coal, there is increased thermal efficiency because of lower excess air requirements and there is a better response to changes in load. Disadvantages of the pulverized coal-fired furnace include: larger power requirements for coal pulverization, larger fly ash discharge due to the generation of more fine particulates, and a larger furnace size for good combustion. Third, in the cyclone furnace, coal is partially crushed and made to pass through a high-temperature combustion chamber called the cyclone. The hot gases pass into the main furnace for cooling, while molten slag is collected in and removed from the cyclone.

In the pulverized coal-fired furnace, coal is fed from a storage pile to a low-capacity hopper. Coal is pulverized as needed from the hopper and blown into the furnace. In the cyclone furnace, coal is usually crushed and mixed with hot gases at each cyclone, which are fed from a central bin.

Boiler Control

Fuel feed, air supply and internal boiler pressure are the three independent variables that must be controlled simultaneously in a furnace. The most important factor affecting response time of the boiler is the rate at which the feed of fuel can be changed. In theory, the amount of air required for complete combustion may be calculated from an analysis of the fuel. In practice, because of inadequate mixing and insufficient time for chemical reactions to reach equilibrium, boilers are supplied with excess air. The amount of excess air is normally held to a minimum because the loss of hot gases up the stack represents a reduction in thermal efficiency of the boiler. Excess air by weight percent of theoretical air in coal-fired furnaces ranges from 15 to as much as 60 percent (2).

Power Plant Circuits

Each steam-electric power plant consists of two major processes, commonly known as the fuel-gas circuit and the water-steam circuit. The fuel-gas circuit has a system of components that influences the rate and level of gaseous emissions from the stack as well as heat transfer in the boiler. Operation of the water-steam circuit primarily affects the overall thermal efficiency of the power plant.

Fuel-Gas Circuit. Coal received at the plant is prepared and stored before combustion. The degree of preparation is dependent on the coal characteristics required for the boiler. Storage requirements are determined by the size of the facility, and the availability of the fuel. After combustion, the ash residue (called "bottom ash") is collected as a solid or liquid depending on the ash fusion temperature of the feed coal. The hot furnace gases contain particulate matter (called "fly ash"), and various oxides, which pass through heat exchangers and ducting and then are either controlled

or pass up the stack. In some installations a portion of the flue gas is fed back into the bottom of the boiler (called "flue gas recirculation"). This can control the formation of oxides and can also influence the heat absorption pattern of the boiler. The hot exhaust gases may also be used to transfer secondary heat to the water-steam circuit (besides in the boiler), or to preheat the air coming into the furnace.

Air pollution emission control is accomplished by modifying the combustion process (e.g., gas recirculation) or by cleaning the hot exhaust gases; gas cleaning usually takes place after the air preheater. There is a variety of processes to control air pollution emissions from coal-fired power plants which are covered in detail in Section 3.5.

The cleaned gases are vented through the stack to the atmosphere normally in the range of 250 to 350°F, while combustion takes place at temperatures greater than 2000°F. The stack provides a natural draft to help move the gases through the furnace (taller stacks provide more draft due to greater differential pressure), and often supplementary fans are utilized.

Water-Steam Circuit. Water is converted to steam in pipes or chambers which surround the furnace. This thermal energy (superheated steam) is converted into mechanical energy by expansion in a steam turbine(s). After leaving the turbine (or the last of a multiple-stage system) the low pressure steam is converted back to water in a condenser. The energy is released by condensation and is absorbed by air or water which is then discharged into the environment.

5.2. ADVANCED COAL-ELECTRIC PLANTS

Fluidized bed combustion and gasification-combined cycle systems are the primary advanced technologies whereby electricity may be directly generated from coal. These technological classifications are not clear-cut as for example gasification may be conducted using fluidized beds. For purposes of this discussion, these technologies will be referred to as advanced coal-electric systems, and direct generation from coal means a technology that uses coal as an input and produces electricity as an output; summaries of these technologies have been published (3,5-10,15).

Fluidized-Bed Combustion (FBC)

The fluidized-bed coal-combustion process involves the combustion of coal within a bed of granular, noncombustible material such as limestone or dolomite (11-15). The bed is supported by a distributor plate, and air is passed up through the distributor plate causing the granular bed particles to become suspended or fluidized. Heat generated in the bed can be removed by heat transfer surfaces placed in the bed. The use of SO₂-control sorbent as the bed material provides a means for removing the SO₂ generated during coal combustion. Fluidized bed systems also offer the potential for inherently low NO_x emissions because of lower combustion temperatures. In most cases SO₂ and NO_x emissions are below present federal standards (20).

For effective combustion of solid fuels, the contact between the solid and a gas (oxygen) must fulfill the following important conditions: (i) large solid surface area, (ii) adequate gas-solid contact time and (iii) adequate gas replacement of burnt gases by oxygen (6). Combustion in a conventional stoker satisfies the second and third conditions, while pulverized coal-firing only satisfies the first condition. A fluidized bed combines the advantages of the stoker and those of pulverized firing by fulfilling all three of the above conditions.

Fluidized beds may be operated at either oxidizing or reducing conditions. Under oxidizing conditions complete combustion is possible and SO_2 is removed as CaSO_4 . To this system would be added a conventional water-steam circuit and electricity would be generated in a steam turbine. When combustion is carried out in a reducing condition (oxygen deficient) a fuel gas (low-Btu) is produced and sulfur is released from the coal as H_2S and is removed as CaS . This type of "combustion" is essentially a gasification process that could perhaps feed a conventional gas-fired power plant to produce electricity. Fluidized beds may also be operated at either atmospheric pressure or at elevated pressures (10-20 atm). Operating at atmospheric pressure, the hot combustion gases would be cooled and vented to the atmosphere. However, in a pressurized combustion system, additional power is generated by a gas turbine which is driven by the hot high pressure gas from the combustor, in a combined-cycle operation. The gas turbine also drives the compressor for the combustion air supply to pressurize the fluid bed.

Characteristics and advantages for the fluidized bed include (6):

- High volumetric heat release rate of 500,000 Btu/hr-ft³, as compared to 20,000 Btu/hr-ft³ in a pulverized coal-fired boiler.
- Low combustion temperatures (1400°F to 1900°F as compared to over 2000°F in conventional boilers) to achieve maximum SO_2 capture by limestone (over 90 percent removal), produce minimum NO_x emissions and avoid clinkering problems.
- The acceptability of low-grade fuels such as refuse from coal preparation, liquifaction residue and gasification char. These high-ash (60 percent) and high sulfur refuse materials cannot be burned in conventional pulverized coal boilers.

Some primary disadvantages of the fluidized bed include (7):

- The maximum removal of about 90 percent of the sulfur in coal, whereas FGD processes are not similarly limited.
- Uncertainty about controlling fine particulate emissions, which may also be a problem with conventional combustion and particulate removal.

Gasification Combined-Cycle Systems (GCC)

Combined-cycle plants are systems incorporating (i) gas turbines exhausting into steam boilers to recover exhaust heat and (ii) use of steam turbines to generate additional electric power. In some cases, the steam boiler is unfired, and the gas turbine generates about half the power. Alternatively, fuel can be burned in the turbine exhaust to increase the amount of steam power generated to as much as 80 percent of the total, with 70 percent of the total fuel burned in the steam cycle. Further descriptions of these cycles, including thermodynamic theory, are readily available (e.g., 6,9-10,15-17). Coal may be used to produce electricity with combined-cycles by adding gasification as an initial step.

The net efficiencies of present combined-cycle plants range from 34 to 35 percent (6), but will likely increase toward 50 percent with further development. The thermal efficiency of the cycle depends on the gas turbine temperature and pressure, the exhaust temperature to the steam-boilers and the percent of air to the gas combustor (16). This net efficiency is greater than that for the conventional steam electric cycle.

Emission characteristics of coal gasification combined-cycles as well as the general environmental impact of gasification-based systems may offer advantages over more conventional power generation systems, as noted in Table 5-2. The conventional coal-fired unit requires handling and storing of about 50 percent more raw material and is estimated to consume about 50 percent more water than GCC technology (17). Also, land disposal limitations may offer an advantage to GCC systems as the sludge disposal problem is eliminated.

Large gasification-combined-cycle plants of 500-1000 MW will likely be made up of multiple trains of about 200 MW each. Each train will probably contain a single large gas turbine. These systems require a high degree of integration between the gasifiers, clean up train, gas turbine and the system cycle. Such integrated systems do not as yet exist, and a realistic appraisal of the necessary technological data for the design of gasification-combined-cycle demonstration plants of 200 MW, or greater, places their operation in the post-1985 period (17).

Table 5-2. Environment Impact of 1000 MW Power Plants.

	Pulverized Coal Boiler with FGD	Gasification- Combined-Cycle
Coal Consumption (lb/KW)	0.87	0.70
Limestone Required (lb/KW)	0.15-0.20	0
NO _x Emissions (ppm)	500	10-40
SO ₂ Emissions (ppm)	10-200	10-200
Particulate Emissions (gm/ft ³)	0.01	unknown
Makeup Water	0.6-0.65	0.4-0.45
Disposal Land (acres)	1200-2400	200-500

Source: EPRI, Reference 17, p. 38.

5.3. OPERATING CHARACTERISTICS FOR CONVENTIONAL COAL-FIRED POWER PLANTS

A description of the primary operating characteristics of a technology is essential for an analysis of this technology within an energy system, e.g., the coal-electric cycle. Thus, the primary operating characteristics for conventional coal-fired steam-electric power plants will be outlined in this section including: load characteristics, availability and performance, heat rate, fuel interchangeability and environmental emissions. A cost summary for conventional systems will also be outlined in this section below.

Load Characteristics

Utility power plants for electrical generation are designed and operated to serve three general load ranges: (i) base-load plants, which are high efficiency plants operated near full capacity most of the time; (ii) mid-range plants that operate at varying loads each day, with about 40 percent utilization; and (iii) peaking plants that are operated only a few hours per day to meet short-term electrical demands.

Fossil-fuel steam electric plants now dominate base-load and mid-load service; gas turbine plants are growing rapidly in peaking service. Within the next two decades new nuclear plants may begin to carry some of the base load, while advanced gas turbines, combined-cycle plants and conventional steam plants will compete for the mid-range load. Gas turbines will continue to dominate the peaking-load service. Load characteristics are described in Table 5-3.

The diurnal variation in load for an electric utility system may be 40 percent of the peak requirement. This is accommodated for by operating a power plant on an average basis at one of various levels of their peak capacity. The level of operation depends on the power plant size, age, fuel usage and the variation in electric power demand that it is required to meet. Coal-fired units are normally operated in a base load condition which is more or less on a continual basis, although significant diurnal or seasonal variations may be required. The load condition affects the operation of both the fuel-gas and water-steam circuits and thus the thermal efficiency (heat rate) of the unit. Typical variations in heat rate with load factors are shown in Table 5-4.

Availability and Performance

Three measures of performance are generally used in the electric power industry to provide an indication of power plant availability, as follows:

Table 5-3. Load Characteristics of Electrical Generating Plants.*

Load Condition	Plant Load Factor**	Types of New Plants 1973-1995
Peak-Load	0-20%	Gas Turbine Fossil-Fuel Steam
Mid-Load	20-70%	Fossil-Fuel Steam Combined Cycle Gas Turbine
Base-Load	70-95%	Fossil-Fuel Steam Nuclear Steam Combined Cycle

*

Source: Battelle, Reference 6, p. 19.

**

Hours of operation, percent of year.

Table 5-4. Effect of Load Factor on Heat Rate for Conventional Steam-Electric Plant.

Annual Load Factor	Heat Rate
30%	12,200 Btu/Kwhr
40%	10,500 Btu/Kwhr
50%	9,600 Btu/Kwhr
60%	9,000 Btu/Kwhr
70%	8,800 Btu/Kwhr
80%	8,700 Btu/Kwhr
90%	8,500 Btu/Kwhr

Source: Battelle, Reference 6, p. 22.

Forced Outage Rate: The ratio, in percent, of the forced outage time divided by the sum of the forced outage time plus in-service time.

Availability Factor: The ratio, in percent, of the time a unit is available for service (whether or not it is actually in service) divided by the period of time (usually one year).

Capacity Factor: The ratio, in percent, of total electric generation divided by the product of the period time multiplied by the maximum dependable capacity (this is often referred to as the plant load factor).

A detailed summary of past performance of fossil-fuel and nuclear power generating units has recently been conducted (29). The cumulative average by size range for fossil-fuel units over the 13-year period from 1960 to 1972 is shown in Table 5-5. This data shows an apparent unit size effect on performance which may be due to increased plant complexity, and the addition of increasing amounts of safety and environmental equipment on newer and larger units. (29, p. 19).

The costs for improving power plant reliability have not yet been identified (29, p. 43), and more extensive cost estimating and cost accounting efforts have been recommended. On the other hand, the benefits have been identified but are complex to analyze. The economic benefits are affected by load demand, the mix of various types of generating capacity, spinning reserve requirements, transmission capability, desired service reliability, fuel costs, operating costs, capital costs, etc. It has recently been estimated that an 8 percent reduction in overall generating reserve requirements by 1985 could produce a savings of as much as 40,000 MW in capacity and \$20 billion in investments (19, p. 44).

Heat Rate

The heat rate is affected by the plant load factor, and is also a function of the plant size. As shown in Table 5-6, the average annual heat rate decreases (thermal efficiency increases) as the size plant increases. Also, gas-fired units generally have a higher heat rate (decreased thermal efficiency) than oil-fired units, and oil-fired units are generally less efficient than coal-fired plants. This reflects the fact that heat transfer is better with solid fuels and poorer with gaseous fuels.

The net thermal efficiency of all steam plants in the U.S. was about 33 percent (10,400 Btu/Kwhr) in 1972, which has been the average for several decades (21). There are no direct technological means to compensate economically for the loss in efficiency by steam plants. Improvements will come instead, from application of advanced power cycles such as combined-cycle plants, and from the general use of cogeneration techniques where fuller use is made of waste heat.

Table 5-5. Fossil-Fired Unit Performance Data, 1960-1972.

Size Range	Number of Units	Forced Outage Rate	Availability Factor	Capacity Factor
60-89 MW	71	1.7%	91.6%	70.2%
90-129	170	3.3%	88.5%	64.3%
130-199	252	3.1%	89.2%	75.3%
200-389	216	4.7%	86.2%	74.8%
390-599	89	8.7%	80.0%	66.6%
600 up	46	16.6%	73.2%	59.7%

Source: FEA, Reference 29, p. 18.

Table 5-6. Typical Average Annual Heat Rates for Baseload Steam-Electric Units.*

Unit Size (MW)	Btu per Net Kilowatt - Hour		
	Coal	Oil	Gas
50	10,250-	10,600-	11,000-
75	10,000-	10,400-	10,750-
100	9,600-9,900	9,800-10,100	9,900-10,200
150	9,400-9,800	9,600-10,000	10,100-10,500
225	9,100-9,500	9,300-9,700	9,700-10,100
350	8,900-9,400	9,300-9,700	9,600-10,000
500	8,800-9,200	9,000-9,400	9,200-9,600
600	8,750-9,150	8,950-9,350	9,100-9,500
700	8,700-9,050	8,900-9,300	9,150-9,450
800	8,600-9,000	8,800-9,200	8,950-9,350
1000	8,500-8,900	8,700-9,100	8,900-9,300

*

Source: Federal Power Commission (in 3, p. 120).

Fuel Interchangeability

Major limitations to the interchangeability of fuels are the problems incurred in substituting a fuel for which the plant was not designed. These problems include changes in slag and ash characteristics and in the grindability properties of coal. Most plants designed for oil or gas cannot be converted to direct coal firing without excessive rebuilding and derating (23). Only about 5-10% of the total U. S. generating capacity could easily be modified from oil to coal burning (24).

Substituting a Western coal for an Eastern coal may involve problems that could result in significant derating or require boiler modification. The use of Western coals in boilers and in pollution control devices may create power plant operational problems that include (25):

Moisture. Higher average moisture contents of Western coals may cause boiler derating and loss of efficiency as compared to design coals.

Ash Slagging. Ash deposits may form on boiler surfaces exposed to radiant heat. This characteristic depends on the ash fusion temperature as well as molten ash viscosity. Western coals may have low to intermediate ash fusion temperatures and low ash viscosity characteristics which could tend to produce ash slagging.

Ash Fouling. Ash deposits may form on surfaces not exposed to radiant heat. A primary coal characteristic that determines this type of ash deposition is the composition of ash minerals; the amount of ash has little influence. Generally, the sodium oxide and calcium sulfate content of the ash are used to predict ash fouling tendencies. The percentage of these minerals may be relatively greater for Western coals.

Coal Abrasiveness. Western coals may contain more quartz and other hard materials and thus its use would affect coal handling and grinding equipment. This property may affect the life of grinding equipment (pulverizers) by a factor of 5 or 10 to 1.

Electrostatic Precipitator. The particulate removal performance of an electrostatic precipitator decreases with increased ash resistivity and decreased particulate residence time. Western coals have lower sulfur content which tends to increase ash resistivity. Therefore, the particulate removal efficiency for Western coals used in existing precipitator designs may be reduced. This can be overcome at increased costs by making the precipitator larger, possibly retrofitting a hot side unit (resistivity depends on flue gas temperature), or using flue gas conditioning. In this latter approach, a small quantity of SO_3 (15-20 ppm) is injected into the fly ash prior to precipitation, thereby lowering fly ash resistivity.

Air Pollution Emissions

Environmental emissions from uncontrolled coal combustion depend on the type of boiler furnace and auxiliaries, the degree of reinjection of fly ash, the type of coal burned, and the load conditions (26). Comprehensive tests for six coal-fired power plant designs under full-load and partial-load conditions are shown in Table 5-7. These and other data have been aggregated to estimate average emission factors as a function of coal characteristics as shown in Tables 5-8 and 5-9.

Oxides of Sulfur. The sulfur in coal appears mainly as SO_2 in the flue gas. The balance of the residual sulfur in the fuel appears as SO_3 , sulfuric acid mist or as other compounds in the fly ash or bottom slag. Between 90 and 100 percent of sulfur entering the boiler in the coal appears as SO_x in the flue gas, and about 1 to 5 percent remains in the ash. When low sulfur lignite containing a high amount of lime (CaO) is burned, it has been reported that nearly all of the sulfur remained in the ash as CaSO_4 (28). Therefore, the presence of trace elements in coal may affect SO_x emissions.

No significant changes in concentrations of sulfur dioxide have been noted between full- and partial-load operations (26) after transient conditions subsided (2).

Oxides of Nitrogen. Oxides of nitrogen are formed largely by high temperature oxidation of atmospheric and fuel nitrogen during combustion. Apparently, the concentrations of NO_x are determined by flame temperature, incomplete decomposition as the gases flow from the flame to the furnace outlet, and rapid quenching of the decomposition reaction as the gases cool in the convective heat-transfer system. Only slight changes in NO_x concentrations were noted with changes in load conditions (26), after transient conditions subsided (2). However, increases in NO_x by as much as 45 percent were noted as measured before and after electrostatic precipitators (26, p. 16).

Particulates. Ash leaving the furnace and entering the fly-ash collector for conventional coal-fired boilers ranges from about 60 to 80 percent of the total; the balance remains as bottom slag. Typical particle size distributions without control equipment, as well as collection efficiencies for several particulate control collection devices are shown in Table 5-10. In general, particulate emissions will depend on load characteristics as discussed in Chapter 6.

Trace Emissions. The amount and composition of mineral matter in the coal largely determines the concentrations of trace metals in the fly ash. The collection efficiencies of these trace elements are nearly the same as those for fly-ash collection (26). Exceptions occur when the fly-ash resistivity is affected as discussed in Chapter 6.

Table 5-7. Typical Emissions of Major Pollutants in Coal-Fired Power Plants(a)

Type of Boiler	Sulfur(c)	Ash(d)	Emissions							
			Fly-ash(gr/scf)(e)		NO ₂ (ppm) ^(f)		SO ₂ (ppm) ^(f)		SO ₃ (ppm) ^(f)	
			B(g)	F(h)	B	F	B	F	B	F
Full-load(b)										
Verticle	2.9	20.2	4.8	0.18	221	310	1450	1730	66	9
Corner	1.7	14.9	3.7	0.23	576	413	1150	1130	8	12
Front-wall	2.3	10.3	2.5	0.44	416	606	2120	1680	11	7
Spreader-stoker	2.8	8.4	2.3	0.38	431	437	1380	1570	58	76
Cyclone	2.4	7.7	1.5	0.39	1204	1160	1350	1360	21	31
Horizontally-opposed	2.4	8.2	4.9	0.68	393	350	1560	1380	10	9
Partial-load(b)										
Verticle	2.8	19.0	4.7	0.11	161	171	1700	1640	46	10
Corner	1.6	13.5	2.9	0.13	393	325	1120	1000	10	12
Front-wall	1.8	9.2	2.4	0.22	500	453	1080	1460	3	20
Spreader-stoker	2.5	8.7	1.5	0.19	430	390	1280	1240	52	69
Cyclone	2.4	7.4	1.8	0.22	742	784	1380	1370	13	22
Horizontally-opposed	2.9	7.8	2.9	0.61	395	328	1780	1680	6	8

^aSource: Reference 26, p. 13.

^bAverage values from two to four tests.

^cMoisture-and ash-free basis.

^dMoisture-free basis.

^eCorrected to 12% CO₂, dry basis.

^fppm by volume, dry basis.

^gBefore fly-ash collector.

^hAfter fly-ash collector.

Table 5-8. Emission Factors for Bituminous Coal Combustion Without Control Equipment (a).

<u>Furnace Size</u> <u>(10⁶ Btu/hr input)</u>	<u>Particulates</u> <u>(lb/ton)</u>	<u>SO₂</u> <u>(lb/ton)</u>	<u>CO</u> <u>(lb/ton)</u>	<u>CH₄(d)</u> <u>(lb/ton)</u>	<u>NO₂</u> <u>(lb/ton)</u>	<u>Aldehydes</u> <u>(lb/ton)</u>
Greater than 100 (Utility and large industrial boilers)						
Pulverized						
General	16A(b)	38S(c)	1	0.3	18	0.005
Wet bottom	13A(c)	38S	1	0.3	30	0.005
Dry bottom	17A	38S	1	0.3	18	0.005
Cyclone	2A	38S	1	0.3	55	0.005
10 to 100 (large commercial and general industrial boilers)						
Spreader stoker	13A(e,f)	38S	2	1	15	0.005
Less than 10 (commercial and domestic furnaces)						
Spreader stoker	2A	38S	10	3	6	0.005
Hand-fired units	20	38S	90	20	3	0.005

^aSource: EPA, reference 27, p. 1-3.

^bThe letter A on all units other than hand-fired equipment indicates that the weight percent of ash in the coal should be multiplied by the value given.

^cS equals the sulfur content (similar to (b) above).

^dHydrocarbons expressed as methane.

^eWithout fly-ash reinjection.

^fFor all other stokers use 5A.

Table 5-9. Emission Factors for Anthracite Coal Combustion Without Control Equipment^a

Type of Furnace	Particulates (lb/ton)	SO ₂ (lb/ton)	SO ₃ (lb/ton)	CH ₄ (d) (lb/ton)	CO(d) (lb/ton)	NO (lb/ton)
Pulverized (dry bottom), no fly-ash reinjection	17A(b)	38S(c)	0.55	0.03	1	18
Overfeed stockers, no fly-ash reinjection	2A	38S	0.55	0.2	2-10	6-15
Hand-fired units	10	38S	0.55	2.5	90	3

^aSource: EPA, reference 27, p. 1-5.^bA is expressed as percent of ash in coal.^cS is expressed as percent of sulfur in coal.^dBased on bituminous coal combustion.

Table 5-10. Percentage Distributions by Size of Particles from Selected Sources without Control Equipment and Average Collection Efficiencies for Various Particulate Control Equipment.*

	<u>Particles by Size Range (%)</u>				
	<u>5</u>	<u>5-10</u>	<u>10-20</u>	<u>20-44</u>	<u>44</u>
<u>Type of Source</u>					
Bituminous Coal					
Pulverized	15	17	20	23	25
Cyclone	65	10	8	7	10
Stoker	4	6	11	18	61
Anthracite Coal	35	5	8	7	45
Fuel Oil	50	**	**	**	0
Natural Gas	100	0	0	0	0
<u>Type of Collector</u>					
<u>Efficiency of Collection (%)</u>					
Simple Cyclone	12	33	57	82	91
Electrostatic Precipitator	72	94.5	97	99.5	100
Venturi Scrubber	99	99.5	100	100	100
Baghouse	99.5	100	100	100	100

*Source: EPA, Reference 27, Appendix A.

**No further breakdown of particle distribution available.

5.4. COST ESTIMATES FOR COAL-ELECTRIC GENERATING TECHNOLOGIES

The price that the consumer pays for electricity is currently regulated by federal and state governments, and depends to varying degrees on long-range supply-demand interactions as well as the established rate structure (30). Peak-load and reverse-scale pricing are currently popular methods suggested for determining the rate structure. A component of consumer price is the cost of bus bar electricity. In this section, cost estimates are reviewed for various coal-electric generating technologies, which can be the major cost component of delivered bus-bar electric power.

Data taken from a periodic steam station cost survey indicate that the bus-bar cost of electricity for new plants increased significantly during 1974 to an average of about 15 mills/Kwhr (31). This was comprised of about 7.5 mills/Kwhr each of fixed and operating expenses. Fuel costs amounted to over 80% of the operating cost. The average cost of construction was about \$190/KW for new plants in the 500- 1000 MW range. Ten year trends for central station plants are shown in Table 5-11; other similar data is also available (e.g., 32).

Conventional Technology

Typical new facility cost data for an 800 MW coal-fired plant, with and without SO₂ controls, is shown in Table 5-12. In mid-1974 dollars the operating and maintenance cost, exclusive of fuel, was estimated to have been about 1.0-1.5 mills/Kwhr; the capital cost was about 275-325 \$/KW. If the fuel cost was \$0.50/10⁶ Btu, and the power plant heat rate was 9,000 Btu/Kwhr, the annual operation and maintenance expense would have been 5.5-6.0 mills/Kwhr. Adding capital charges at 15 percent capital recovery and assuming 70 percent operating factor, the total cost for power generation for conventional 800 MW coal-fired units in mid-1974 would have been approximately 12-15 mills/Kwhr.

Variations in capital cost with size have been estimated, as shown by example in Table 5-13. Also, estimates of the escalation in capital cost have been made as displayed in Table 5-14.

Projected electric generating costs by each major conventional technology type are shown for various conditions in Table 5-15. Conventional coal-fired plants that produced electricity at 12.4 mills/Kwhr in 1974 may produce the same electricity at between 16 and 19 mills/Kwhr in 1979 (\$1979), and at between 21 and 29 mills/Kwhr in 1984 (\$1984). This variation significantly depends on the cost of fuel, which may more than double over that time period (not measured in constant dollars).

Table 5-11. Estimated Central Station Power Plant Factors, 1964-1974^a

Year of Survey ^b	<u>1974</u>	<u>1972</u>	<u>1970</u>	<u>1968</u>	<u>1966</u>	<u>1964</u>
Total busbar electricity (mills/Kwhr) ^c	15.1	8.0	7.2	6.0	5.8	6.8
Construction cost (\$/Kw) ^c	193	144	126	118	119	127
Fixed charges (mills/Kwhr) ^c	7.6	3.8	3.7	3.1	2.6	3.3
Operating costs (mills/Kwhr) ^c	7.5	4.2	3.5	2.9	3.2	3.5
Fuel cost (¢/10 ⁶ Btu) ^c	73	36	28	24	26	26
Manpower (employees/Mw)	0.16	0.17	0.14	0.16	0.17	0.21
Heat rate (Btu/Kwhr)	10,380	10,120	9,930	9,980	9,710	10,350
Average annual plant factor (%)	54.6	57.9	62.8	62.6	65.0	62.5
Average utilization factor (%)	93.2	98.6	98.0	99.7	98.5	96.7

^aSource: Electrical World, reference 31.

^bStations with units added since previous survey and operated through the survey year.

^cDollars in year of survey.

Table 5-12. Typical New Facility Cost Data \$Mid-1974.

	Size (MW)	Operating Factor	Operation and Maintenance (Exclusive of Fuel)	Capital Cost \$/KW	Scale Factor
Coal-Fired Unit with SO ₂ Control	800	70%	1.43 mills/Kwhr	326	0.6
Coal-Fired Unit Without SO ₂ Control	800	70%	1.20	276	0.6

Source: Bechtel, Reference 3.

Table 5-13. Unit Capital Costs of Power Plants as a Function of Unit Size (1981).*

Plant Type	Unit Size (MW)				
	600	800	1000	1200	1300
Nuclear (PWR)	703	641	598	565	552
Coal (with SO ₂ control)	545	510	485	467	459
Oil (with SO ₂ control)	494	461	438	421	413
Oil (without SO ₂ control)	420	392	372	358	352

*

Source: AEC, Reference 33.

Table 5-14. Estimates of Coal-Fired Power Plant Installation Costs
1000 MW.*

Year of Operation	Cost Basis	Installation Cost \$/KW
Late 1972	3/67	110
Mid-1975	6/69	200
January 1978	1/71	280
January 1981	1/73	450
January 1983	7/74	625
* Source: AEC, Reference 33.		

Table 5-15. Projected Electric Generating Costs at Station Bus-bar during Initial Year of Commercial Operation(a)

Plant Type	1974	Cost (mills/Kwhr)			1984		
		1979					
Oil-fired (600-800Mw)							
Fixed charges	4.5	6.6	6.6	6.6	9.7	9.7	9.7
Operation and Maintenance	0.5	0.8	0.8	0.8	1.0	1.0	1.0
Fuel-\$12.00/bbl(b)	17.0	17.0			17.0		
-escalated at 5%			21.7			21.7	
-escalated at 10%				27.4			44.2
Total	22.0	24.4	29.1	34.9	27.7	38.4	59.9
Coal-fired (600-800Mw with SO ₂ Controls)							
Fixed charges	7.2	10.6	10.6	10.6	15.6	15.6	15.6
Operation and Maintenance	0.7	1.1	1.1	1.1	1.4	1.4	1.4
Fuel-\$12.50/ton(b)	4.5	4.5			4.5		
-escalated at 5%			5.7			7.3	
-escalated at 10%				7.3			11.7
Total	12.4	16.2	17.4	19.0	21.5	24.3	28.7

Table 5-15. (Cont.)

	<u>1974</u>		<u>1979</u>		<u>1984</u>		
Nuclear (1000-1300Mw)							
Fixed charges	7.4	10.9	10.9	10.9	16.0	16.0	16.0
Operation and Maintenance	0.5	0.8	0.8	0.8	1.0	1.0	1.0
Fuel-\$0.18/10 ⁶ Btu ^(b)	2.0	2.0			2.0		
-escalated at 5%			2.6			3.3	
-escalated at 10%	—	—	—	<u>3.2</u>	—	—	<u>5.2</u>
Total	9.9	13.7	14.3	14.2	19.0	20.3	22.2
Gas-fired (600-800Mw)							
Fixed charges	3.3	4.9	4.9	4.9	7.1	7.1	7.1
Operation and Maintenance	0.4	0.6	0.6	0.6	0.8	0.8	0.8
Fuel-\$0.40/10 ³ CF ^(b)	4.0	4.0			4.0		
-escalated at 5%			5.1			6.5	
-escalated at 10%	—	—	—	<u>6.4</u>	—	—	<u>10.4</u>
Total	7.7	9.5	10.6	11.7	11.9	14.4	18.3

^aSource: Reference 34.^bRepresentative of first quarter 1974 prices.

Table 5-16. Comparison of Utility Power Generation Costs for
Different Types of Plants.^a

Plant Type	Sulfur Control	Fuel Type	Thermal Efficiency (Base Load)
Conventional Steam-Electric	Scrubber	C/HS coal ^c	37%
	LS Coal	W/LS coal ^d	38%
	LS Coal	Refined	38%
	Clean Fuel	Lo-Btu Gas	38%
Fluidized-Bed Steam-Electric Steam-Electric	Conventional	C/HS Coal	37%
	AFB ^e		
	Advanced	C/HS Coal	37%
Combined-Cycle	AFB		
	Advanced PFB	C/HS Coal	38%
Combined Cycle			
Current (1974)	Clean Fuel	Lo-Btu Gas	35%
Future	Clean Fuel	Lo-Btu Gas	45%
Future	Clean Fuel	H. Lig. GT	45%

NOTE: Table continued on following page.

Table 5-16. (continued)^(j)

Plant Type	Capital Cost (\$/KW)	Fuel Cost ^b (\$10 ⁶ Btu)	Cost of Electricity Base Load ^h	(Mills/Kwhr) Peak Load ⁱ
Conventional	236	0.35	10.2	54.1
Steam-Electric	220	0.75	12.3	50.4
	208	0.71	11.6	48.0
	186	0.87	12.5	77.2
Fluidized-Bed	230	0.35	9.6	48.4
Steam-Electric				
Steam-Electric	199	0.35	8.5	42.8
Combined-Cycle	204	0.35	8.7	44.6
Combined-Cycle				
Current (1974)	151	0.87	13.0	76.8
Future	101	0.879	10.3	62.4
Future	112	1.66	16.7	51.1

a Source: Battelle, Reference 6, p. 15.

b Costs for desulfurized coal, liquid fuels and gaseous fuels are based on central high-sulfur coal (L/HS) at \$0.35/10⁶ Btu.

c Central/high sulfur coal.

d Western/low sulfur coal.

e Atmospheric fluidized bed.

f Pressurized fluidized bed.

g Cost of low-Btu gas adjusted for base-load factor of 70%.

h Base-load factor = 70%.

i Peak-load factor = 10%.

j Data on this page refers to Sulfur Control and Fuel Type as noted on previous page.

Advanced Technology

Some early (mid-1974) cost estimates for advance coal-electric technologies are shown in Table 5-16. These early data show that fluidized-bed systems are cost competitive with conventional steam-electric systems using scrubbers as well as low sulfur coal. They also show that for high efficiency combined-cycle generation, the cost approaches that for conventional technology.

More recent cost estimates for advance coal-electric technologies are shown in Table 5-17 (20). In late 1975 dollars, fluidized-bed and gasification combined-cycle plants are approximately cost equivalent. Higher efficiency systems such as MHD and fuel cells are also cost competitive; however, gas turbines are more expensive. Although operation and maintenance costs, exclusive of fuel, are approximately the same for each advanced system, there may be significant differences in fuel and fixed charges. Therefore, the relative cost advantages of these advanced systems will depend on fuel and capital escalation rates, and will thus change through time.

A recent summary of the cost of "ten ways to clean coal" is shown in Tables 5-18 and 5-19 (35). Capital costs are shown in Table 5-18 including the power plant and sulfur removal system separately. Also shown are estimates of contingency and uncertainty associated with each cost estimate, so that a range of capital costs are displayed. The base capital cost for each plant is given in mid-1975 dollars per kilowatt. In each case, this figure consists of total construction cost, including contractor's overhead and fee, land cost and owner's head office costs. It excludes contingency, escalation, and interest during construction; thus a contingency was added for each case. Interest during construction, together with startup costs were incorporated into the uncertainty range at a rate of about 30%. The capital costs for solvent-refined coal and petroleum-type fuel options do not include increments for their respective coal liquefaction plants; these costs are incorporated into the fuel costs at \$2.50-\$2.75/10⁶ Btu and \$3.50-\$3.75/10⁶ Btu, respectively.

Estimated busbar power costs for each of the ten coal-electric technologies are shown in Table 5-19. Values are calculated for both baseload operation (65% capacity factor) and intermediate or cycling operation (35% capacity factor). The busbar cost comprises both fixed and variable expenses. Fixed charges are calculated using an 18 percent capital recovery factor (current U. S. utility experience varies between about 15 percent and 20 percent). This fixed charge rate covers interest on debt, return on equity, depreciation, insurance and federal, state and local income and property taxes. Variable charges include the cost of fuel, chemicals, operation and maintenance. Two levels of coal cost were investigated, \$1/10⁶ Btu and \$2/10⁶ Btu, but only the former is shown in Table 5-19. Chemical costs were negligible for most plants (0.1-0.2 mills/kwhr), except for coalfired plants using scrubbers and for the atmospheric fluidized-bed combustion plant. Operation and maintenance costs were estimated on the basis of plant complexity, ranging from 2 to 4 mills/Kwhr for based-loaded plants, with an additional 0.5 mills/Kwhr for intermediate load operations.

Table 5-17. Summary of Advanced Coal-Electric Technology Cost, Efficiency and Construction Data^a Late 1975.

Technology	Prime Contractor ^c	Net Output MW	Net Thermal Efficiency
Pressurized Fluidized Bed	GE	904	39%
Pressurized Fluidized Bed	W	678	---
Combined Cycle with Gasification	GE	847	40%
Combined Cycle with Gasification	W	874	---
Combined Cycle with Liquefaction	GE	585	38%
Combined Cycle with Liquefaction	W	787	---
Atmospheric Fluidized Bed	GE	814	36%
Potassium Topping Cycle	GE	995	44%
Helium Gas Turbine	GE	469	40%
Open Cycle MHD	GE	1932	48%
Fuel Cell	UTC	638	50%

Technology	Capital Cost ^b \$/Kwe	Construction Time-Years	Cost of Electricity (mills/Kwhr) ^b			
			Fixed Charges	Fuel	O&M	Total
Pressurized Fluidized Bed	723	5.5	22.9	8.7	2.5	34.1
Pressurized Fluidized Bed	546	5.0	17.3	8.8	2.0	28.1
Combined Cycle with Gasification	418	5.0	13.2	15.0	1.3	29.1
Combined Cycle with Gasification	336	4.0	10.6	14.7	0.9	26.2
Combined Cycle with Liquefaction	772	5.0	24.4	8.6	2.2	35.2
Combined Cycle with Liquefaction	633	5.0	20.0	7.3	2.4	29.7
Atmospheric Fluidized Bed	632	5.5	20.0	9.5	2.2	31.8
Potassium Topping Cycle	935	5.5	29.6	7.7	2.5	39.8
Helium Gas Turbine	1232	5.0	38.9	8.6	1.8	49.3
Open Cycle MHD	727	6.5	23.0	7.3	1.7	32.0
Fuel Cell	590	---	----	---	---	28.7

a Source: ECAS, Reference 20.

b Approximate late-1975 dollars, base-load plants.

c GE--General Electric, W--Westinghouse, UTC--United Technology Corp.

Table 5-18. Capital Costs for Ten Clean Ways to Burn Coal(a) Mid-1975

Power Plant Type	Heat Rate (Btu/Kwhr)	Base Cost (\$/Kw)	Contingency (%)	Uncertainty (%)	Total Cost(b) (\$/Kw)
Conventional Steam Plants					
Low-sulfur coal	9,000	290	+10	<u>+10</u>	375-460
High-sulfur coal with alkali scrubbing	9,500	PP:290(c) SR: 50 340	+10 +20	<u>+10</u> <u>+20</u>	485-625
High-sulfur coal with regenerative scrubbing	10,000	PP:290 SR:150 440	+10 +20	<u>+10</u> <u>+20</u>	575-740
Atmospheric Fluidized-bed combustion	9,500	PP:340	+20	+25, -15	450-665
Solvent-refined coal	9,000 BC:10,000(c)	PP:290	+15	<u>+15</u>	375-500
Petroleum-type fuel	9,000 BC:13,400	PP:190	+10	<u>+10</u>	259-300
Low-Btu, moving-bed dry ash Lurgi process	BC:13,600	PP:190 SR:390 580	+10 +20	<u>+10</u> <u>+15</u>	760-1000
Medium-Btu gas, slagging moving-bed process	BC:11,300	PP:190 SR:255 455	+10 +20	<u>+10</u> +25, -15	585-800

Table 5-18 (cont.)

Power Plant Type	Heat Rate (Btu/Kwhr)	Base Cost (\$/Kw)	Contingency (%)	Uncertainty (%)	Total Cost ^(b) (\$/Kw)
Conventional Steam Plants					
Low-Btu gas, atmospheric, two-stage entrained process	BC:10,600	PP:190 SR:210 <u>400</u>	+10 +20	+10 +25, -15	525-710
Medium-Btu gas, pressurized, two-stage entrained process	BC: 9,800	PP:190 SR:155 <u>345</u>	+10 +20	+10 +25, -15	490-600
Combined-Cycle Plants					
Petroleum-type fuel	7,500 BC:11,200	PP:160	+15	+15	185-250
Low-Btu gas, moving-bed dry ash Lurgi process	7,500 BC: 9,500	PP:160 SR:335 <u>495</u>	+15 +20	+15 +15	650-875
Medium-Btu gas, slagging	7,500 BC: 9,100	PP:160 SR:215 <u>375</u>	+15 +20	+15 +25, -15	490-695
Low-Btu gas, atmospheric, two-stage entrained process	7,500 BC: 8,400	PP:175 SR:180 <u>355</u>	+15 +20	+15 +25, -15	460-650
Medium-Btu gas, pressurized, two-stage entrained process.	7,500 BC: 8,500	PP:160 SR:130 <u>290</u>	+15 +20	+15 +25, -15	375-530

^aSource: EPRI, reference 35.^bTotal capital cost includes indirect costs and startup at 30% (22% for combined-cycle petroleum-type plant).

CPP = power plant, SR = sulfur removal system, BC = basis coal (coal conversion and power generation).

Table 5-19. Estimated Busbar Power Costs for Coal-Electric Technologies^a Mid-1975.

	Busbar Power Cost (mills/Kwhr) ^b	
	Base-Load	Intermediate-Load
Direct Utilization		
Low-sulfur coal	25-28	36-41
Alkali scrubbing	28-34	42-52
Regenerative scrubbing	30-36	46-56
Fluidized-bed	28-36	41-55
Liquefaction		
Solvent-refined coal	36-42	47-57
Petroleum-type fuel		
Conventional	42-48	51-56
Combined-cycle	36-41	45-51
Gasification		
Low-Btu gas (MB) ^c		
Conventional	42-49	64-78
Combined-cycle	36-42	52-65
Medium-Btu gas (SMB) ^c		
Conventional	36-42	51-64
Combined-cycle	29-33	42-54
Medium-Btu gas (E)		
Conventional	30-35	45-50
Combined-cycle	24-30	33-44

a Source: EPRI, Reference 35.

b Base-Load = 65 percent capacity factor; Intermediate-load = 35 percent capacity factor.

c MB = moving-bed, SMB = slugging moving-bed, E = entrained.

Recent findings and conclusions for the cost of advanced coal-fired technologies include (35):

- Direct firing of low-sulfur coal has the lowest busbar power cost for both base-load and intermediate operations of 25-28 mills/Kwhr and 36-41 mills/Kwhr, respectively.
- Direct firing with wet alkali scrubbing is the second most attractive base-load option at 28-34 mills/Kwhr using high-sulfur coal.
- Busbar power costs for base-load operation are in the 25-40 mill/Kwhr range, except for Lurgi low Btu gas and petroleum-type liquids fueling conventional steam plants.
- Regenerative scrubbers, advanced gasifiers (beyond the Lurgi), and atmospheric fluidized-bed combustors are all comparable for use with conventional steam plants.
- The combined-cycle versions of advanced gasification processes show promise of being less costly than using low-sulfur coal.
- Combined-cycle plants using petroleum-type fuels and medium-Btu gas from advanced gasifiers have comparable costs for intermediate service.
- Atmospheric fluidized-bed combustion looks attractive in base-load operation, but there is significant uncertainty in its economic performance.

CHAPTER 5

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EMISSIONS CONTROL TECHNOLOGY

The three primary residuals that are emitted by the use of coal in steam-electric power plants, sulfur oxides, nitrogen oxides and particulates, may be controlled by technologies based on combustion modification and post-combustion methods. In this section, background information, performance data and summary costs are presented for various technologies that are designed to control continuous emissions from coal-fired power plants. The emissions control technologies discussed in this section include:

- Flue Gas Desulfurization
- Nitrogen Oxides Control
 - Combustion Modification
 - Postcombustion Methods
- Particulate Control
 - Mechanical Collection (gravitational, centrifugal)
 - Wet Collectors
 - Electrostatic Precipitator
 - Fabric Filtration (Baghouse)

Other technologies capable of only regulating emissions from steam-electric power plants, e.g. tall stacks, are not discussed in this report.

6.1. FLUE GAS DESULFURIZATION

The requirements for clean air can in part be met by the abatement of emissions of sulfur oxides from stationary combustion sources. SO_x emissions in 1975 totaled 150 million tons per year worldwide, and 33 million in the United States. The health hazards associated with sulfur oxides and sulfate particulates in the environment has required the need for control of these pollutants. Among various SO_x control alternatives, the use of flue gas desulfurization (FGD) technology can reduce the total level of SO_x emissions, and can help to ease the burden to supply electricity from oil and gas by allowing for the use of higher sulfur content coals.

Flue gas desulfurization technology is under intensive research and development efforts to more effectively demonstrate the commercial-scale feasibility for burning high sulfur and high ash fuels. There appears to be little doubt that eventually, scrubbers on coal-fired boilers will operate adequately for use in the utility industry. The present commercial status of FGD technology is discussed below. When more fully commercialized, the market potential for FGD systems will depend on its economics, the availability of material resources for its

construction, operation and maintenance, and on the need to meet air quality emission regulations on a specific regional geographic basis.

FGD Technology

Flue gas desulfurization is a type of source control by liquid scrubbing that involves the removal of contaminants in either vapor or particulate state from an effluent gas stream (28). The transfer of pollutants requires the contacting of a gas and liquid and the subsequent removal and regeneration or disposal of the liquid stream. The primary mechanism for the gas to liquid transfer of contaminants is diffusion. Gaseous mass transfer proceeds by the movement of material from a region of high concentration to one of low concentration. The chemistry of FGD systems is highly complex especially for high-sulfur or high-trace metal fuels.

It is unlikely that a single flue gas cleaning method will be developed that will control all forms of effluents from all types of sources. The control technique to be used will depend on factors such as boiler size, plant configuration, age, load pattern, characteristics of the fuel, by-products and geographical area. In 1972 there were about 12 FGD processes which had been used or were being considered for use in commercial-scale demonstration tests or in commercial practice (1). By 1975 the number of processes available on the market reached nearly 50 (7). Lime and limestone scrubbing processes are the only systems to date that have proved commercially viable for use with coal-fired power plants. Process descriptions are classified into those systems that are regenerable or recoverable and those termed throwaway or nonregenerable. Recoverable processes are designed to attempt to provide an economic byproduct from the desulfurization process, generally in the form of sulfuric acid, elemental sulfur or possible gypsum. Throwaway processes have the requirement of the disposal of solid and liquid waste. There are economic tradeoffs between the capital, operation, maintenance, materials, byproduct income and waste disposal costs. In addition, some processes are add-on types that can be installed just prior to the stack. Other types require higher temperatures and are usually inserted ahead of the air heater. Add-on types are the most suitable for retrofitting existing power plants. A list of the most commonly used FGD systems in the U.S. includes:

- Wet Limestone Scrubbing
- Wet Lime Scrubbing
- Alkali Scrubbing without Regeneration
- Alkali Scrubbing with Calcium Regeneration
- Alkali Scrubbing with Thermal Regeneration

- Wellman-Lord/Allied Chemical
- Magnesium Oxide Scrubbing
- Sodium Carbonate
- Catalytic Oxidation

There are various published surveys of FGD technologies (3,7,14, 18,29,30,33,71,71,81,82,105,117) and current literature may be obtained by contacting vendors or contractors (31,32).

Initial projections of FGD installations indicated that for on-line operation in 1976, 98 FGD units would have been installed or were planned for utility plants that would have produced a total of 38,000 MW. By 1980, 90,000 MW of generating capacity was initially estimated to be equipped with FGD systems (2). A more recent survey of the status of domestic FGD systems has revealed that by late 1976, approximately 10,000 MW of FGD capacity will be installed of which 50 percent will be retrofit applications (25). By 1980, approximately 45,000 MW of capacity will be installed of which 30 percent will be retrofit. As of November 1975 the status of FGD systems is indicated in Table 6-1 (25). EPA is publishing surveys of various domestic FGD operations (72), and other status reports have been published (105,117).

Commercial Status for Low Sulfur Coal

The commercial operation of flue gas desulfurization technology for coal-fired power plants using low sulfur coal is currently practiced, and scrubbers are now available for purchase as routine components of power systems covering a wide range of specific conditions. This has not always been a certainty. Many problems have been encountered in early installations of FGD systems, especially on coal-fired units, and this discouraging experience has caused utilities and industry to question the feasibility of this technology. Now, advances in the knowledge of process design and in materials selection have been sufficient to provide reasonable assurance that scrubber failures will not be the result of faulty design (4).

Although there have been several multi-million dollar failures of large-scale FGD development tests for both domestic, industrial and government efforts, as well as tests in Japan and Germany, more recent experience has indicated commercial-scale success (5). Coal-fired facilities of 100 MW and greater, which use lime and limestone processes, have been operated for several months for both open and closed loop water systems. Further experience is likely desirable for other than lime and limestone scrubbers on coal-fired plants; however, other processes have been demonstrated on a commercial scale for oil-fired boilers.

Table 6-1. United States Flue Gas Desulfurization Systems as of November 1975.

<u>Status</u>	<u>No. of Units</u>	<u>MW</u>
Operational		
Active	23	4,693
Inactive	5	605
Under construction	18	6,171
Planning		
Contract Awarded	10	3,761
Letter of intent	8	2,325
Requesting/evaluating bids	5	2,577
Considering only FGD systems	46	24,007
Total	115	44,139

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The question of commercial availability is the subject of much current discussion (7). The "design" or "drawing board" availability certainly differs from the availability of "off the shelf" equipment for construction. Also, the lead time for turn-key status is a consideration when utility-scale operation is required. The total time requirements may be from 5 to 14 years; lag times on ordering and installing equipment can vary between 2 and 5 years (9).

Environmental Implications

Although a properly operated FGD system can reduce SO_x emissions by 80 to 90 percent and thus help provide for the maintenance of cleaner air, another pollution control problem is associated with the disposal of lime and limestone sludge. Without proper disposal techniques, the environmental burden is shifted from potential air pollution to solid waste and/or water pollution problems. The environmental impacts of each type of stack gas desulfurization process are different, depending primarily on whether the method is throwaway or regenerable (70). An assessment of the external costs of environmental impacts can serve to add additional information for process selection.

In terms of quantity, the estimated sludge production in 1978 for Ohio may present a disposal problem on the same scale as municipal refuse (7). A typical 1000 MW coal-fired power plant* will produce 1.46 million tons of scrubber and coal ash sludge per year. By 1980, a projected 90,000 MW of installed FGD systems may produce as much as 131 million tons per year (10). Other more recent estimates are 5.8 million and 71.4 million tons per year for 1975 and 1980 respectively (37). The historical and potential future solid waste generation from electric utilities indicates an increase of solid waste generation by 1980 of as much as 200 percent above current levels (37).

*Three percent sulfur, 12 percent ash, 73 percent load factor, 0.88 lb/Kwh coal usage, 85 percent SO₂ removal efficiency and 50 percent moisture in sludge.

Ponding and landfilling appear to be the most practical and economic methods of scrubber sludge management (16). Proper pond design and operation can minimize water pollution problems. The installation of a pond liner and operation in a closed loop mode, i.e., no external discharges, can prevent water pollution by leaching and runoff. Liner costs are approximately equivalent to \$5/KW capital and 0.15 mills/Kwh annualized operation (3). Landfilling can be used in an environmentally acceptable manner if the sludge is stabilized by chemical fixation to strengthen and harden the slurry mixture. Costs of chemical fixation have been reported to be as high as \$15/ton on a dry solids basis (3). Therefore, for a typical 1000 MW coal-fired power plant, since 0.73×10^6 tons of sludge on a dry solids basis will be generated, annual costs for sludge disposal may reach 11 million dollars. This would be equivalent to approximately 1.7 mills per Kwh or \$3.90 per ton of input coal.

The problem of ultimate disposal for the solid wastes from lime/limestone scrubbers must be considered. In addition to providing for various degrees of water pollution, one of the difficulties in sludge disposal is that potential useful products are discarded. Besides the potential for the extraction of sulfur products, sludge may be utilized in a variety of schemes, including: structural filler material, road bases, concrete and aggregate products, plaster and wallboard, and mineral recovery. Several EPA studies are currently underway in this area.

Although there seems to be a potential for ash utilization (38), more research and development is required to establish utilization methods that would be both technically and economically feasible. Fly ash has been generated in large quantities for over 30 years, however, in 1970, only 7 percent of all the fly ash generated by coal burning plants was utilized (37).

Coal ash and scrubber sludge have been shown to contain other recoverable products besides ash material. Metals (11) and rare elements (12) have been discovered which could be a potential environmental hazard. Also, uranium has been found in coal.

The use of recoverable processes will control environmental damage from residual disposal although an economic tradeoff exists between costs and by-product credits. General aspects of this tradeoff are described below.

FGD Operations and Market Consideration

Flue gas desulfurization technology must be designed and operated within the context of existing and planned utility systems. Factors that influence the operations, and thus the marketability of FGD technology, include: sulfur removal performance, the availability of materials such as lime and limestone, the characteristics of available coal, particulate removal performance, boiler derating, retrofitting problem, by-product markets, and institutional constraints. These

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Table 6-2. Estimates for Availability of Limestone for Flue Gas Desulfurization.

Region	Millions of Tons/Year	
	Estimated 1980 FGD Demand	Total Present Production
New England	1.4	2.4
Middle Atlantic	6.6	90.9
East North Central	14.3	185.6
West North Central	2.7	92.5
South Atlantic	8.5	87.5
East South Central	5.6	81.3
West South Central	----	58.3
Mountain	1.4	10.7
Pacific	0.3	18.8
TOTAL	40.7	628.0

in 1971 was about \$15 per ton, and has sharply increased over the past several years as demand has grown. However, this will not present an ultimate problem as lime may be made by calcining limestone.

Particulate Removal. The design trend for FGD systems has been to provide an independent particulate removal system ahead of the scrubber instead of relying on the scrubber for this purpose. Fly ash has been observed to interfere with both the chemistry and operation of scrubbers. However, almost all of the FGD technologies report the removal of fly ash, which among other parameters, is a function of particulate size. The collection efficiency decreases rapidly with decreasing particle size in the fine particle region (36).

To provide for additional particulate control, a venturi scrubber could be incorporated into an FGD system prior to each scrubber train. According to a recent study, this could be accomplished for approximately the same capital cost (\$21/KW for limestone, \$1975) as that for an electrostatic precipitator, depending on the input coal properties and the degree of control required (25).

Scrubbers have the potential of removing up to 99.5 percent of the particulate matter from combustion products (34); however, the feasibility of commercial scale long-term application of scrubbers to remove SO_x as well as fly ash, has not yet been demonstrated.

NO_x Control. FGD technology may be designed and operated by using chemical catalysts or adsorbents to aid the chemistry of scrubbing. Although still in a research and development status, recent pilot plant tests using a char adsorbent have shown that some of the NO_x present in the flue gas was removed (35).

The nature of FGD design is such that partial removal of the three primary residuals, sulfur, ash and nitrogen, is accomplished. This capability is inherent in the wet chemistry of the gas-liquid interface; however, due to the high variability of coal properties, a single-purpose technology may not be feasible except after much research and development.

By-Product Markets. The possible by-products from an FGD process are primarily sulfur and sulfur-related compounds. These include elemental sulfurs, sulfuric acid, sulfur dioxide (liquid), gypsum (calcium sulfate) and sodium sulfite or sulfate. The net cost of recovery vrs. disposal of FGD sludge may offer a competitive advantage over other suppliers of sulfur-related products; however, the transportation costs, plus the cost of storage to supply fluctuating demands, appears to suggest that by-product disposal may be the least cost alternative. This of course may not be true for local market or long-term situations. Also, the total "cost" to the environment may not be a priori economic; physical or social "costs" may be inherently incurred by the disposal of sludge and ash. However, from a market point of view, the projected

potential sulfur by-product supply may exceed the total domestic sulfur demand by 1977, and may continue to exceed needs through the year 2000 (19).

Boiler Derating. In comparison to the operation of a power plant without emission controls, the operation of an FGD system will require typically from 4 to 7 percent of the plants' generating capacity (17,20). This does not appear to be an unreasonable burden, however, it necessitates the construction or upgrading of electric power generating facilities to meet a reserve capacity requirement for the prevention of utility system curtailments. The costs of this 4 to 7 percent derating will depend on the peak to base load ratio, age, size, fuel use, etc for the existing and planned units.

FGD Capacity. Full-scale FGD installations that were operating as of May, 1974 amounted to 15 units with a total capacity of 2,655 MW (15). There were 53 units planned or committed as of May, 1974, totalling about 27,000 MW, which are scheduled to come on-line by 1979. Approximately 65 percent of these units use lime/limestone scrubbing technology. This rate represents an equivalent compound rate of 93 percent per year. Earlier estimates suggested that as much as 48,000 to 80,000 MW of FGD capacity would be on-line by 1977 (2). Although not all coal-fired plants are required a priori to be equipped with FGD systems, the present and near-future demands for FGD technology far exceed the ability of vendors to deliver, and which is more important, the utility industry to install, maintain and operate. More recent reports on FGD capacity are available (105,117).

Institutional and Other Constraints. Two recent studies have been concerned with institutional and other barriers to the commercialization of FGD technology (2,21). These are summarized as follows (3):

- Reserve Capacity

Typical utilities require a reserve capacity of about 20 percent within any power region. The installation of an FGD system requires about 4 to 7 percent of a plants' output capacity which will lead to a decrease in the system reserve. In addition, a facility would be shutdown during the retrofit installation, which because of the scheduling difficulties, no more than 10 to 20 percent of the capacity could be retrofitted each year. This is a rate limiting parameter which is interesting to compare with other forecasts. This reserve capacity problem is compounded by the ability of FGD systems to operate only over a narrow load range. Recent experience may suggest that FGD systems have an optimum design and operation only over a narrow load range, which is not as wide as might be expected to be experienced at electric utilities (37). Therefore, during the utility wide installation of FGD technology, if the reserve capacity requirements are to be maintained, the performance of already installed FGD systems could likely be impaired due to the increased loads that would be required. Recent innovations include a modular FGD design so that modules may be removed or added as load changes.

- Manpower

Technical skill in the design and operation of FGD systems may not generally be available. This is especially true if the utilities themselves attempt to conduct in-house engineering. The chemical process engineer has not been traditionally in demand by the utilities, but recent trends indicate that this will not create serious constraints.

- Regulatory Disincentives

A short-term alternative for the utilities is the purchase of low sulfur fuel oil and/or coal. With the use of fuel clauses, the sometimes much higher costs as compared to other longer-term alternatives, can be passed on directly to the customer. However, utilities must apply for rate increases to recover the capital and operating expenses of scrubbers. This process may be time consuming and is subject to regulatory delays.

Flue Gas Desulfurization Costs

There is a large amount of literature accumulating on the costs of FGD systems, much in summary form (e.g., 2,3,13,17,20, 22,106) and some in detail (23-27). A survey and overview of recent findings is included in this section.

Cost Summary. A recent survey of FGD costs based on vendor quotes is shown in Table 6-4 (25). The sizes shown cover the total range which may be encountered in FGD systems. This data represents model plant estimates derived by fitting equations to field data. Annualized costs are the sum of operation, maintenance charges and fixed charges; the costs are in January 1975 dollars and do not include escalation through project completion. Both new and retrofit FGD installations are considered, and estimating parameters such as raw materials, utilities, manpower wage rates, etc, are based on midwest locations. The costs are based on meeting the New Source Performance Standard of 1.2 lbs SO₂ per million Btu for high sulfur coal (about 80 percent removal) and a standard of 0.15 lbs SO₂ per million Btu for low sulfur coal (about 90 percent removal). Variations in capital costs are shown in Table 6-7. The data in Table 6-4 compares favorably with recent industry surveys as shown in Tables 6-5 and 6-6 (15).

Variations in capital cost factors are shown in Table 6-7 for the typical FGD systems in Table 6-4. These variations in initial costs can be the results of varying SO₂ removal requirements to meet regional emission regulations, difficulty of retrofit, particulate control requirements, flue gas flow rate, escalation or inflation rates and site specific factors. The variability in SO₂ removal requirements is a function of the sulfur content of the coal used. In addition to those factors shown in Table 6-7, capital costs may vary +\$10/KW for limestone scrubbing, and +\$30/KW for the sodium solution process, as the sulfur content of coal varies from 1 to 6 percent by weight. Flue gas flow rates may result in capital cost

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Source: Pedco, Reference 25.

Table 6-5. Costs for Installed FGD Systems (\$1975).

	Capital Cost-- \$/KW		Operating Cost-- mills/Kwh	
	EPA (Pedco)*	EPRI (Battelle)**	EPA (Pedco)*	EPRI (Battelle)**
Cholla 1	44	55	5.5	1.7
Mystic 6	25	43	3.9	3.0
Will County 1	96	108	4.5	10.4
Phillips	70	124	2.1	--
Wood River 4	73	84	4.0	--
Hawthorn 3	19	25	2.5	--
Hawthorn 4	19	25	2.2	--
La Cygne	43	51	---	1.5
Paddy's Run 6	57	57	---	--
Stock Island	--	20	---	0.7
Arthur Kill	--	380	---	--
Reid Gardner 1	--	38	---	--
Reid Gardner 2	--	38	---	--
Mohave 2	--	50	---	--

*

February 1975 report by Pedco to EPA on status of flue gas desulfurization systems in the U. S.

**

Trip reports by staff members--Battelle Columbus Stack Gas Pollution Control Coordination Center.

Table 6-6. Costs for Scrubbers Under Construction or Planned (\$1975).

<u>Unit</u>	<u>Capital Cost--\$/KW</u>
Mill Creek 3	43
Cane Run 4	43
Cane Run 5	46
Cane Run 6	46
Black Dog	50-70
Dean H. Mitchell	117
Kammer	88
Bruce Mansfield	136
Eddystone 1	50
Widows Creek 8	65

SOURCE: Reference 15

Table 6-7. Variations in Capital Cost Factors for FGD Installations.

<u>Factor</u>	<u>Typical Total Capital Cost Impact, Percent</u>
SO ₂ removal requirements*	15-20
Flue gas flow rate*	10-30
Installation status* (new vs retrofit)	10-40
Condition of terrain and subsurface*	3-15
FGD system redundancy**	10-40
Particulate control requirements*	25-35
Sludge disposal requirements (Nonregenerative processes)	10-30

Source: Reference 25.

*

Variations in capital cost are from a model plant 500 MW/existing/
3.5 percent S boiler.

**

Variations in capital cost for 250-1000 MW model plants.

variations from \$60 to \$100/KW and \$94 to \$145/KW, for the limestone and sodium solution scrubbing systems, respectively.

Higher capital costs are often required for the installation of an FGD system or an existing power plant. This is mainly because of fixed space requirements, but can also be due to process design and control as well as mechanical factors (21). Table 6-8 shows typical capital cost variations for various retrofit installations. The range is substantial. Previous data had suggested that a 25 to 30 percent cost increase would seem to be typical (3,26).

Particulate control, if required, could be incorporated by the addition of venturi scrubbers, and would add about 30 percent (\$21/KW for the limestone system and \$34/KW for the sodium solution process) to a capital cost of a 500 MW existing plant using 3.5 percent sulfur coal. The cost of an electrostatic precipitator currently ranges between \$20 and \$40/KW.

As discussed above, disposal costs for nonregenerable FGD processes may require a significant expense. Ponding of scrubber sludge and fly ash may increase operating costs by over 1 mill/Kwh (3). Sludge fixation, instead of ponding, will further increase the operating costs; a cost of \$4.50 per ton is approximately equivalent to 0.6 mills/Kwh.

There is a tradeoff between nonregenerable FGD (sludge disposal) and regenerable FGD (by-product credits). As a rough guide, EPA estimates that if the cost of sludge disposal exceeds \$4 to \$6 per ton (wet basis), a regenerable process which recovers a useful by-product, will be more economic than a nonregenerable process. Under 1973 market conditions, a net sales revenue of \$5 to \$9 per ton was indicated from FGD by-products (27), although the sulfur products market may be saturating.

Table 6-9 gives some recent indications as to the additional revenues required for the regenerable and nonregenerable FGD alternatives (27). Variations in the cost of waste disposal, from the assumed service fee of \$10 per ton used in Table 6-9, indicate variations in the total annual cost of between 3.5 and 4.5 mills/Kwh, for disposal costs of approximately \$4 to \$16 per ton respectively.

Cost Estimating Factors. Cost estimates for a particular technology may be influenced significantly by factors which are related to its installation and subsequent operation. Some of these factors include variable project scope, time frame, design and operating conditions, vendor optimism and overselling, changes or confusion in regulatory requirements, variable by-product and by-product value/disposal costs, and unexpected events such as legal considerations or labor disputes. It is almost certain that installed costs, under today's conditions of inflation and uncertainty, will always exceed vendor estimates.

Table 6-8. Variations in Capital Costs for Retrofit Installations.

<u>Retrofit requirements</u>	<u>Capital cost¹ increase, %</u>
Long duct runs	4-7
Tight space	1-18
Delayed construction ² (1 yr delay)	5-15
New Stack	6-20

Source: Reference 25.

¹For a model plant 500Mw/existing/3.5%S boiler.

²Varies with escalation rate during period(s) of delayed construction.

Table 6-9. Revenue Requirements for FGD Systems with By-Product Credits and Sludge Fixation (\$1978).

<u>Process</u>	<u>Tons By-Product</u>	<u>Annual Revenue Requirements, Mills/Kwh</u>		
		<u>FGD System^a</u>	<u>Includes By-Product Credit^b</u>	<u>with Fixation^c</u>
Limestone	206,000 ^d	3.41	---	4.01
Lime	175,000 ^d	3.65	---	4.15
Magnesia	110,400 ^e	4.02	3.23	--
Cat-Ox	137,400 ^f	3.65	3.04	--
Sodium	32,700 ^g	5.37	4.99	--

Source: Reference 27.

a New 500-MW, coal-fired unit, 3.5 percent S in coal, 7,000 hr/yr.

b One hundred percent sulfuric acid at \$25/ton, 80 percent acid at \$16/ton, sulfur at \$45/long ton (\$40.18/ton).

c Assuming sludge fixation service fee by contract treating sludge in the utility's pond at \$10/ton of 100 percent solids.

d One hundred percent solids.

e One hundred percent H₂SO₄.

f Eighty percent H₂SO₄.

g Elemental sulfur.

Retrofitting FGD installations can be especially prone to factors that are outside the scope of cost estimating. A study conducted for the state of Ohio has revealed that there is a distribution of facilities corresponding to the difficulty of the degree in installation problems and thus installation costs. A certain percentage of Ohio power plants may be retrofitted fairly easily, while some facilities may be very difficult if not impossible (3). The incremental costs for installation under this situation tend to increase with the fraction of total capacity retrofitted.

Summary

Flue gas desulfurization technology offers the potential for commercial-scale control of residual emissions to the air, especially sulfur oxides, from the combustion of coal. Several processes are currently available for commercial use, including most notably lime and limestone scrubbing. Projections of FGD installations indicate that approximately 45,000 MW of capacity will be on-line by 1980, of which 30 percent are expected to be retrofit. This will represent an installed capacity of approximately 16 percent of the total U.S. coal-fired power plant capacity by that time.

Estimated vendor costs in \$1975 for FGD systems are shown in Table 6-4. Total operating expenses, including fixed charges, for nonregenerable limestone scrubbing range from about 3 to 5 mills/Kwh. Total operating expenses for regenerable systems range from about 3.5 to over 6.5 mills/Kwh in January 1975 dollars. Recoverable processes tend to cost more than throwaway types, although the cost of sludge disposal may account for a major expense. Variations in cost factors are shown in Tables 6-7 and 6-8.

6.2. NITROGEN OXIDES CONTROL

Stationary sources currently contribute more than 50 percent of the man-made emissions of nitrogen oxides (NO_x) in the U. S. Utility boilers and stationary engines burning coal, gas and oil are the primary NO_x emitters. The oxides are formed either by the oxidation of atmospheric nitrogen at high temperatures (thermal NO_x) and/or by the oxidation of nitrogen compounds in the fuel (fuel NO_x). As much as half of the total stationary emissions may be contributed by the oxidation of the nitrogen in the fuel, primarily from the burning of heavy oils and coals (3).

Control Technology Summary

Current NO_x control technology is based primarily on modifications of the combustion process (3,39,41). These methods suppress NO_x formation by either reducing the oxygen content or the temperature in the localized combustion chamber. This technology exceeds the state-of-the-art that is required to meet the existing new source performance standards for oil and gas-fired plants. However, current technology for combustion modification in coal-fired plants may still have boiler

reliability maintenance and economic issues which are unresolved (51).

NO_x control technologies still in the research and development phase include post-combustion flue gas treatment methods. These processes may utilize a catalytic approach which is becoming more technically and economically feasible (40). Also, the flue gas treatment approach has the potential of simultaneously reducing SO_x and NO_x (39, 40). These technologies, their commercial status, environmental implications, operations and economics are discussed in this subsection. Prior to this a brief review of alternative control methods will be outlined.

Alternative Control Methods

Ambient air concentrations of NO_x may be controlled with the use of tall stacks and intermittent operations such as fuel switching and load switching. The use of these techniques has been primarily directed at the control of sulfur oxides, and to some degree particulates. These methods may not reduce overall NO_x emissions to the atmosphere, although they are substitutable to some degree with the NO_x reduction technologies primarily discussed in this subsection for controlling ambient air concentrations.

The use of tall stacks will theoretically reduce maximum ground level NO_x concentrations because of dispersion and dilution. However, since the residence times of nitrogen related compounds is increased for tall stack emissions, secondary pollutants may be formed to a greater degree. Also, NO_x may be released into ozone-rich air layers.

The use of fuel and load switching procedures are relatively limited for reasons which include the following (58):

- . Complex chemical reactions between NO_x and other pollutants which makes the prediction of ground level concentrations uncertain
- . Thermal nitrogen is produced in the combustion process which is independent of fuel nitrogen
- . The variation of nitrogen (in fossil fuels) may not as great as that for sulfur or ash
- . There are no short term Federal ambient air quality standards for NO_x so that intermittent control to reduce peak concentrations is not required.

This report does not include an assessment of the control strategies that affect ambient air quality (i.e., short-time period and meteorologically related), but rather with fuel-related allocation and residuals management options. Analysis of the former options is the subject for integrated technology-meteorology studies.

NO_x Control Technology

The commercial technologies of NO_x control and reduction are primarily based on combustion modification methods. There are currently no commercial precombustion techniques for reducing fuel nitrogen, although chemical methods have been researched (57).

Conventional Technology. NO_x formation may be controlled in the combustion process itself, to a limited degree, by reducing both the oxygen concentration and/or the temperature in localized regions of the combustor, usually near the flame (3). Reductions of the oxygen content in the flame zone reduces the emissions of both fuel and thermal NO_x, however, reduction in temperature can only significantly reduce thermal NO_x. Conventional techniques to control NO_x by reducing combustion temperature include: injection of cooled combustion products, steam, or water in the flame volume; reduction of preheated combustion air temperature; and heat extraction from the flame. These techniques are accomplished generally by recycling the cooled combusted flue gas to the burner area (referred to as flue gas recycle), or by a burner design that allows the entrainment of colder combustion products by the hot exhaust gases. Techniques to lower the oxygen concentration in the flame zone involve lowering the volume of air supplied to all burners which reduces the overall air/fuel ratio (referred to as low-excess-air firing) or reducing the air/fuel ratio for some burners, without reducing the overall air/fuel ratio (referred to as staged combustion). Unfortunately all of these techniques may produce incomplete combustion thus increase emissions of carbon monoxide and particulates. Also, the techniques of water injection and reduced air preheat usually incur an unacceptable penalty for thermal efficiencies of the boiler. Flue gas recirculation may be the most effective for gas-fired units but is relatively ineffective for oil and coal-fired units for which fuel NO_x is significant. The use of coal produces the serious operational and control problem of slagging and corrosion of the boiler. However, by the utilization of a combination of control techniques, an average reduction in emissions of 37 percent has been achieved for coal-fired units (3). Higher reduction efficiencies are likely possible for specific situations; however, more research is required, especially for coal-fire power plants (76).

Combustion modification methods for existing boilers may not always be applicable. Boilers can generally be adapted for low-excess-air firing and staged combustion, however, flue gas recirculation may be impractical for retrofitting units with existing air ducts.

The available methods for reducing NO_x emissions, in decreasing order of preference with respect to operational effectiveness and overall efficiency have been ranked by the American Gas Association as (41):

- . Low-excess-air Combustion
- . Staged Combustion
- . Flue Gas Recirculation
- . Water Injection
- . Reduced Air Preheat

Perhaps more recent data indicates that most of the NO_x control systems to be purchased by utilities in the near term involve gas recirculation (39). NO_x control performance in coal-fired boilers is currently the subject of intensive research (59).

The capital costs may vary over a wide range for combustion modification methods to reduce NO_x emissions. Typical ranges, in \$1973, may be from \$0.50/kw for staged combustion to \$6.0/kw for flue gas recirculation on existing units, and from negligible costs for staged combustion to \$4.0/kw for flue gas recirculation on new units. Operation and maintenance costs are strictly dependent on the site-specific situation (42,59), and fuel costs will be reflected in the loss of conversion efficiency. The economics of NO_x control technology are outlined in more detail below.

Advanced Technology. In addition to controlling NO_x within the combustion process, research is currently being conducted to assess the viability of utilizing chemical additives and physical methods for postcombustion control (39, 40). Also, advanced methods of combustion modification are being researched.

NO_x control from power plants by catalytic processes appears both technically and economically feasible on the basis of laboratory-scale data and preliminary engineering analysis; however much additional research is required. In this technology, chemical catalysts are selected which have the thermo-chemical potential to reduce nitrogen oxides to the chemical forms of elemental nitrogen, carbon dioxide and water. The primary nitrogen oxide in flue gases, nitric oxide (NO), is both insoluble and relatively inert, so that the use of catalysts can be an effective means for controlling emissions. Physically, the flue gases are passed through a bed arrangement which contains an absorbed catalytic material; the catalyst is often recycled. Two types of catalytic NO_x abatement processes have exhibited the best potential for power plant adaptation according to a recent assessment (40): selective NO_x reduction with ammonia and nonselective simultaneous NO_x - SO_x reduction with coal derived reductants (CO and H_2).

In addition to NO_x abatement by chemical methods of flue gas treatment, physical techniques may be used. These techniques center around the absorption (scrubbing) and adsorption processes, and are similar to FGD technology. With intensive efforts to commercialize scrubber technology to remove SO_2 , it would seem that much interest

would have been generated to attempt to remove NO_x using similar methods. This apparently has not been the case. Historically, the economics of conventional NO_x control have been much less than that for scrubber systems. Also, NO_x control has seldom been required. Therefore, there has been little economic incentive to investigate the use of scrubber techniques to control NO_x emissions. This will likely change due to the fairly rapid entry of FGD systems into utility markets, and the possibly low marginal costs of controlling NO_x on existing scrubber installations.

The technologies which chemically or physically remove oxides of nitrogen from flue gases are more expensive than conventional combustion modification approaches. These advanced technologies are "second generation" control methods that have current application only if NO_x emission regulations are tightened. The economics of these technologies are described in detail below; however, for catalytic control, capital cost estimates in 1973 range from \$6 to \$9/kw for new installations, and may be as high as \$18/kw for retrofitting an 800 Mw power plant. Total annual operating costs may range from 0.4 to 1.5 mills/kwh (47).

Commercial Status of NO_x Control Technology

Conventional Technology. Current NO_x regulations for steam generators can potentially be met with the existing technology described above as combustion modification methods. These state-of-the-art technologies can reduce NO_x emissions to approximately 300-350 ppm, while the current new source performance standard is 500 ppm for NO_x emission from coal-fired power plants (48). Low-excess-air firing, staged combustion, flue-gas recirculation, water injection and reduced air preheat are control techniques that have been successfully demonstrated on field units, primarily with oil and gas-fired units. For coal-fired units, accelerated corrosion testing over 300 hours showed no adverse effects, but longer range trials for a wide range of coals have yet to be completely tested (43). Some boiler reliability, maintenance and economic issues for coal-fired operations have yet to be resolved (51).

Many of the results reported to date using combustion modification methods have been from tests performed on small-scale units. Although these data have indicated promising results, the general application of test results to large-scale operational systems often introduces significant problems. Also, operation at the utility scale, where retrofit applications are necessary, involves overcoming problems of the site specific installation, as well as market economics, materials and equipment availability and institutional considerations. Research is only currently being completed that for the first time will provide operating data for utilities that elect to control emissions by the staged-combustion method with coal-fired boilers (39). It should also be noted that high intensity combustion burners may be required to burn certain types of coal, which will likely yield higher emissions.

Advanced Technology. NO_x control processes that utilize catalytic methods with flue gases appear both technically and economically feasible based on laboratory research and development (40). However, much additional small- and large-scale testing will be necessary before catalytic postcombustion control methods will become commercially feasible. These technologies are second-generation methods as compared to the combustion-modification techniques discussed above, and will only likely be required at commercial scale if NO_x emission regulations are reduced, or if high-nitrogen fuel sources are heavily utilized, such as coal.

Recently, several compounds have been identified that can selectively and noncatalytically reduce NO_x at temperatures and residence times characteristic of the convective heat transfer sections of a boiler (39). This approach may represent the lowest cost NO_x emissions control method, however, much additional research is required.

Environmental Implications

Unlike FGD and particulate control technology, the waste products of NO_x control technology are minimal. However, the use of combustion modification techniques tends to increase hydrocarbon and particulate emissions, especially if water- or steam-injection methods are utilized. Also, if catalytic methods become popular, trace metal pollutants may present problems, since these metals act as the primary chemical reactants in the catalyst.

A recent study of ozone concentrations in non-urban environments has indicated that high levels may be formed from NO_x emitted in stack gases (56). NO_x has also been observed to have an effect on the ozone concentrations in upper atmospheric layers.

NO_x Control Technology Operations and Market Conditions

Factors that affect both the technological and market performance of NO_x control technologies include: NO_x removal efficiencies, the effect of other residual control technologies on NO_x emissions, the effect of NO_x control technologies on power plant operations, retrofitting problems and institutional constraints. Process-specific problems will not be discussed in detail as they are described elsewhere (40, 41, 44).

NO_x Formation and Removal. The formation and degree of removal of NO_x in power plant operations depends on the properties of fuel and thermal nitrogen, as well as the operating conditions and physical configurations of the particular plant. Any factor which influences temperature and oxygen concentration profiles in a combustor may influence NO_x emissions. This makes general analysis difficult for any practical system since any of the following are potential variables: fuel/air ratios, fuel/air mixing patterns, fuel type, interaction of different burners and configuration of heat transfer surfaces. Also, NO_x formation is influenced by hydrocarbons, which tend to produce nitrogen-containing compounds which may be later oxidized

to NO_x in the atmosphere. NO_x formation and removal may be classified by three levels of technology: uncontrolled, control by combustion modifications and control by postcombustion methods.

NO_x emission rates for existing boilers in uncontrolled situations range from about 0.53 to 2.04 lbs (NO_2)/ 10^6 Btu for coal-fired units at full load (44); the current EPA new source performance standard is 0.7 lbs (NO_2)/ 10^6 Btu. However, high temperature combustion can increase NO_x emissions. Emissions as high as 2.2 to 2.5 lbs (NO_2)/ 10^6 Btu have been observed from cyclone coal-fired boilers (48). EPA emission factors for uncontrolled bituminous- coal-fired boilers are shown in Table 6-10 (55). It should be noted that these emission factors are averaged values and that the variance can in some cases be considerable (60). Unlike SO_x formation, NO_x is formed by both fuel-related and thermal processes.

The percent conversion of fuel nitrogen to NO_x has been studied in laboratory scale combustors, primarily for oil-fired operations (45). Data indicates that the percent conversion of fuel nitrogen to NO_x decreases as the percent of nitrogen by weight in the fuel increases. For coal-fired operations, where the fuel nitrogen ranges from approximately 1.2% to 1.6% by weight, the percent conversion of fuel nitrogen to NO_x decreases from about 30-40% to in the range of 15-20% (45). Although the mechanism of fuel nitrogen conversion is not completely understood, and the contribution of fuel NO_x is difficult to separate from thermal NO_x , Table 6-11 gives a likely range on the upper bound of the fuel nitrogen component of NO_x emissions from uncontrolled power plants using typical coals. The conversion of fuel nitrogen to NO_x is found to increase markedly with increased oxidizing conditions in the flame but is insensitive to changes in temperature (44).

Emissions from coal-fired units are dependent on the power plant load or operating factor as both fuel and thermal NO_x tend to increase with increasing load. Recent data has indicated that for coal-fired power plants, about 20% of the fuel nitrogen, which averaged 1.3% by weight, was converted to NO_x , and that fuel nitrogen contributed 50% of the emissions at full load (50). The relative proportion of fuel NO_x and thermal NO_x may depend upon many variables including coal moisture content, nitrogen content, burner design, furnace design and operating conditions.

By the utilization of a combination of combustion modification control techniques, an average reduction in emissions of 60% has been achieved for gas-fired units, 48% for oil, and 37% for coal (43). The percent reduction may be greater for a selected technology and specific design; however, the thermal efficiency of combustion may be adversely affected (e.g. water injection). An assessment of the range of NO_x reduction efficiencies for combustion modification methods is shown in Table 6-12 (42). Data in this table for coal-fired power plants are estimates based on a conservative evaluation of NO_x reduction potentials (61). More recent data suggests that

Table 6-10. Emission Factors for Nitrogen Oxides from Bituminous Coal Combustion without Equipment Control: Utility and Large Industrial Boilers¹

<u>Boiler Type</u>	<u>Nitrogen Oxides²</u>
General	18
Wet Bottom	30
Dry Bottom	18
Cyclone	55

¹Source: Reference 55

²Pounds of NO emitted per ton of coal burned

Table 6-11. Range of the Probable Upper Bound of Fuel NO_x from Uncontrolled Power Plants (lb NO₂/10⁶Btu)

<u>Coal Type</u>	<u>PERCENT FUEL NITROGEN CONVERTED</u>	
	<u>15%</u>	<u>40%</u>
1.2%N 10,000Btu/lb	0.59*	1.57
1.6%N 15,000Btu/lb	0.52	1.40

$$*0.59 = \frac{(1.2)(3.28)(0.15)}{1.0}$$

Table 6-12. Public Utility Boilers: Estimated % NO_x Reduction by Combustion Modifications¹

Boiler Size	LEA ²	Two-Stage	LEA + Two-Stage	FGR ³	LEA + FGR	Water Injection
1000 MW						
Gas	33	50	90	33	80	10
Oil	33	40	73	33	70	10
Coal	25	35	60	33	55	10
750 MW						
Gas	33	50	85	33	80	10
Oil	33	40	73	33	70	10
Coal	25	35	60	33	55	10
500 MW						
Gas	33	50	70	33	70	10
Oil	33	40	65	33	65	10
Coal	25	35	55	33	55	10
250 MW						
Gas	33	45	60	30	60	10
Oil	30	35	55	30	55	10
Coal	25	30	50	30	50	10
120 MW						
Gas	33	40	53	30	53	10
Oil	30	30	45	30	45	10
Coal	25	25	40	30	40	10

¹Source: Reference 42.²LEA: Low excess air firing.³FGR: Flue gas recirculation for NO_x control.

NO_x reductions using staged combustion may be as high as 50% in new coal-fired furnaces (66).

For existing units, low excess air-firing was observed to reduce NO_x emissions by as much as 50%, while flue gas recirculation only exhibited moderate reduction of about 5% in NO, even at 30% flue gas recycle.

Because of the importance of fuel NO_x for coal-fired operations, techniques that reduce temperature in the flame zone will be less effective in controlling NO_x emissions than those that reduce the oxygen content. Low-excess-air firing and staged-combustion have been observed to reduce NO_x emissions from coal-fired units by an average of 37% for 12 units in field tests funded by the EPA (50). Additional current tests are being conducted that will provide more operating data for utility-scale operations using the staged-combustion method (39).

NO_x may be removed selectively or non-selectively from flue gases by the use of physical and chemical methods. A recent assessment of chemical catalysts for control of NO_x from stationary power plants has indicated that a 90% or greater removal efficiency is technically feasible (40). These removal efficiencies are sensitive functions of flue gas temperature, oxygen, nitrogen and hydrocarbon concentrations, as well as sulfur-related and other compounds in the fuel.

NO_x - SO_x Removal. The simultaneous reduction of NO_x and SO_x emissions may become a desirable scheme for many coal-fired power plant operations. These techniques may involve the use of catalysts, adsorption, absorption or physical separation.

Catalytic processes may be of a non-selective nature, which implies that sufficient chemical reductant is present in the flue gas to reduce all the oxidant constituents of the stream, primarily O₂, SO₂, and NO_x. These reductants will likely have to be added to the flue gas for coal-fired operations, whereas sufficient reductant generation during combustion (i.e. combustion modification) for simultaneous NO_x - SO_x reduction, is possible with natural gas- and oil-fired boilers (54). In some designs, reductants such as CO and H₂ may be generated from the coal itself.

There are few catalysts that operate effectively in the power plant flue gas environment where NO_x, CO₂, H₂O, O₂ and SO_x are all present. Sulfur compounds can severely poison catalytic activity. Copper based catalysts appear to be the most effective while rare earths and certain transition metals have been tested (54). Only preliminary data from bench scale tests for simultaneous NO_x - SO_x reduction using catalysts have been collected. Several promising catalysts have been identified and conceptual engineering and economic studies have been conducted which indicate the feasibility for such emission control schemes. In one case, NO_x was completely reduced to nitrogen while approximately 80% of the SO_x was simultaneously reduced to

elemental sulfur. In a second case virtually all NO_x and SO_x were reduced to nitrogen and recoverable metallic sulfides. Major economic and operational uncertainties exist for adapting these schemes to existing coal-fired power plants (40).

Flue gas cleaning processes such as wet limestone scrubbing, and the use of other alkaline solutions or sulfuric acid appear to offer some potential for simultaneous NO_x - SO_x removal (62, 67). The reduction of NO_x from flue gases is inherently more difficult than the reduction of SO_x . This complication arises because the predominant compound found in flue gases, nitric oxide (NO), is relatively unreactive. Also, more reactive species such as CO_2 , SO_2 and water will compete with NO and thus interfere with its removal (69). These factors will tend to cause increases in scrubber capacity and thus costs in order to achieve effective NO_x removal efficiencies. However, this method does offer the combined control of NO_x , SO_x as well as particulates.

NO_x Formation in Electrostatic Precipitators. Ozone and atomic oxygen may be formed in the corona discharge of an electrostatic precipitator. These may subsequently react with nitrogen to form additional nitrogen oxides. A comprehensive summary of emissions from coal-fired power plants has been conducted which revealed that concentrations of nitrogen oxides measured at the outlet of electrostatic-type fly-ash collectors were 40 to 45 percent higher than those measured at the inlet at full load conditions (56). However, no increase in levels were found at reduced loads, and the phenomenon was not noticed for all types of boiler/ash-collector combinations. Very little information is available on this subject; however, the mechanism appears to be related to the presence of specific hydrocarbon compounds, which if available in sufficient quantity, can even act to remove NO_x (63).

NO_x Control and Power Plant Thermal Efficiency. Reductions in the thermal efficiency of a power plant that utilizes an NO_x control technology will be the most significant for a method such as water or steam injection. Due to the recent increases in fuel prices, this technique will not likely be used. For high nitrogen fuels such as coal, reductions in flame temperature will not significantly influence NO_x emissions, so that for combustion modification techniques, reduction in oxygen content will be required. Reductions in thermal efficiency may be less for this reason. A reduction of 1% in thermal efficiency has been used for "worst case" analysis with the steam or water injection method (64). For low-excess-air firing, thermal efficiency has been observed to increase by as much as 2% (65).

NO_x Control and Power Plant Load. A combustion modification technique such as flue gas recirculation requires power for fan operation. For coal-fired power plants this may reduce the boiler load by as much as 10% to 20% (59), and this would have the effect of decreasing the net energy output from the power plant. A combustion modification technique such as low-excess-air firing or staged combustion will not likely derate the boiler capacity.

The postcombustion NO_x control method of flue gas scrubbing may have an effect on net power plant capacity while the use of catalysts will not likely reduce power output. Scrubber operations are described in further detail in the section on flue gas desulfurization.

Institutional and Other Constraints. Several constraints may be imposed on the commercialization of the NO_x control industry, primarily for retrofit installations, which include (58):

. Reserve Capacity

A minimum reserve capacity of about 20% is maintained within any power region. This reserve must be maintained during installation and maintenance of NO_x control systems which will involve scheduling of equipment outages.

. Fuel Availability and Power Plant Conversion

Natural gas and distillate fuel oils have traditionally been used to produce electricity by combustion methods. These fuels are low in nitrogen but are now in short supply. With the likely switch to coal, which has relatively high nitrogen content, the NO_x control industry will be limited by the convertability of existing power plants to coal and the rate at which new coal-fired power plants come on line.

. Retrofit Modifications

The cost of some NO_x control methods for retrofit applications may be excessive. Single unit boilers for example may not be readily adapted for two-stage combustion modification. Also, the application of flue gas recirculation, which requires additional air ducts, may be different for its operation on existing units.

NO_x Control Costs

Far less is known about the commercial-scale economics of NO_x

The cost of some NO_x control methods for retrofit applications may be excessive. Single unit boilers for example may not be readily adapted for two-stage combustion modification. Also, the application of flue gas recirculation, which requires additional air ducts, may be different for its operation on existing units.

NO_x Control Costs

Far less is known about the commercial-scale economics of NO_x control technologies than for SO_x and particulate systems. The costs

for combustion modification may be significantly less than those for postcombustion control, although removal efficiencies are less. Costs for tall stacks and intermittent control techniques are not considered.

Combustion Modification Costs. The costs for control of NO_x by combustion modification generally include: annual fixed charges on capital; direct operating cost such as maintenance, supplies and overhead; additional fuel costs due to decreased thermal efficiency; and additional power costs due to fan operations. Additional fuel costs are incurred when a technique such as water injection is used, and additional fan power costs are incurred for flue gas recirculation methods.

Costs available in the current literature are somewhat preliminary. Estimates based primarily on gas- and oil-fired power plant data made by Bartok, et. al. (42) are shown in Table 6-13, using the assumptions as noted. These cost estimates (circa 1970), revealed an economy of scale for capital-intensive methods, while the costs for additional fuel or power were constant with scale. These preliminary data showed that the total annual costs for combustion modification ranged around approximately 0.1 mills/Kwh in 1970. The corresponding NO_x reduction efficiencies for these methods are shown in Table 6-12.

More recent data (circa 1973), based on some coal-fired power plant experience for single furnaces, is shown in Table 6-14 (59). Again, some economies of scale were estimated for capital-related items. These more recent data showed that the total annual cost for NO_x control ranged from approximately 0.10 to 0.34 mills/Kwh in 1973, except for overfire air, which had a low capital cost, and no additional fuel or power expenses. Experience has shown that these methods have corresponding NO_x reduction efficiencies as high as 40% to 50% (59,66).

Postcombustion NO_x Control Costs. Preliminary engineering design and cost analyses have been conducted for five postcombustion NO_x abatement schemes on 800Mw power plants (40). Cost data in \$1973 are shown in Table 6-15; also included are the most cost sensitive items. These five schemes were based on proof-of-principle data and are consequently a preliminary process design and cost effort. Laboratory data have shown that these methods have the potential of reducing NO_x emissions by as much as 80% to 90%. It should be noted that capital costs do not include return on investment, and a 90% operating factor was assumed for calculating total annual cost.

Preliminary NO_x Control Cost Comparison. Based on the Cost data in Tables 6-13 through 6-15, and on typical NO_x reduction efficiencies associated with NO_x control methods, preliminary ranges in the cost per ton of NO_x controlled and emitted are shown in Tables 6-16 and 6-17. These cost comparisons are based on the general rate of uncontrolled NO_x emissions of 18 lbs NO per ton of coal burned (Table 6- and assuming a 10,000 Btu/lb coal burned in a 750-800Mw coal-fired power plant with a heat rate of 9000 Btu/Kwh. This preliminary data shows that although there may be significant variations in the cost

per ton of NO_x control for either combustion modification or postcombustion technologies, there is a definite difference in cost per ton between these alternatives. The average combustion modification cost was \$38/ton of NO₂ emitted, while average postcombustion catalytic cost exceeded \$180/ton, for the same coal used in the same boiler.

Summary

The technology for controlling nitrogen oxides emissions from coal-fired power plants include combustion modification and postcombustion methods. Combustion modification technology is currently adequate for meeting the federal new source performance standard of 0.7 lbs NO_x per million Btu. However, more advanced technology will be required if environmental emission standards are reduced.

Preliminary cost estimates for NO_x control methods are shown Tables 6-13 through 6-15, and a range of cost comparisons on a per ton basis are exhibited in Tables 6-16 and 6-17.

Table 6-14. Operating Costs of NO_x Control Method for New Coal-Fired Power Plants: Single Furnace¹ (\$1973).

Control Method	Overfire Air (20%)		Windbox Flue Gas Recirculation (30%)		Coal Mill Flue Gas Recirculation (17%)		Water Injection	
	100	750	100	750	100	750	100	750
Mw Rating	100	750	100	750	100	750	100	750
Capital Cost ² (\$/Kw)	0.31	0.12	3.5	2.2	3.0	1.9	1.6	1.1
Annual Fixed Charge ³ (mills/Kwh)	0.009	0.003	0.104	0.065	0.089	0.056	0.047	0.033
Direct Operating Cost (mills/Kwh)	-	-	-	-	-	-	-	-
Additional Annual Fuel Cost ⁴ (mills/Kwh)	-	-	-	-	-	-	0.272	0.272
Additional Annual Fan Power Cost ⁵ (mills/Kwh)	-	-	<u>0.039</u>	<u>0.039</u>	<u>0.041</u>	<u>0.041</u>	<u>0.024</u>	<u>0.024</u>
Total Annual Operating Cost (mills/Kwh)	0.009	0.003	0.143	0.104	0.130	0.097	0.343	0.329

¹Source: Reference 59.²Delivered and erected (+10%). Excludes interest during construction. \$1973³16% capital charge, 5400 hr/yr.⁴\$0.50 per million Btu, 9,400 Btu/Kwh, approximately 6% reduction in thermal efficiency.⁵\$250/HP fan power cost, or \$40/HP per year.

Table 6-15. Capital and Operating Cost Estimates for Catalytic NO_x and NO_x-SO_x Reduction Schemes on 800 Mw Power Plants¹

Cost Item	NO _x -SO _x Catalytic Reduction Process ²		NO _x -SO _x Reduction Sulfide Process ³	NO _x Reduction by NH ₃ : New Plant	
	New Plant	Existing Plant		Non-Noble Metal Catalyst	Noble Metal Catalyst
Capital Cost					
Total (\$10 ⁶)	7.31	14.94	5.08	4.93	7.72
Per KW	9.13	18.67	6.35	6.15	9.64
Operating Cost ⁴					
Annual (\$10 ⁶)	2.53	4.00	9.48	5.64	7.39
mills/Kwh	0.40	0.62	1.50	0.88	1.15
Major Cost Items	Ducts, Catalytic Reactor	Heat Exchanger, Duct	Scrap Iron	NH ₃	NH ₃ , Catalyst

Source: Reference 40.

¹Costs do not include working capital and return on investment. Ten year straight-line depreciation was used. Maintenance, insurance, taxes = 8% of capital (annually). Power cost = 1.4¢ per Kwh. Catalyst replacement (regeneration of Pt) once per year. Costs based on \$1973.

²Sulfur credit not taken.

³Scrap iron was costed at \$100 per ton. The iron is not regenerated.

⁴Includes depreciation, maintenance, insurance, taxes, labor, electric power, energy losses and materials, 90% operating factor.

Table 6-16. Range in Preliminary Costs per Ton for NO_x Control by Combustion Modification

Control Method	%NO _x Reduction ¹	lbs NO ₂ /ton coal		lbs NO ₂ /10 ⁶ Btu		\$ /ton NO ₂			
		C ²	E ³	C ²	E ³	0.05 mills/Kwh ⁴	E ³	0.1 mills/Kwh ⁴	E ³
Uncontrolled	0%	0	28 ⁵	0	1.4 ⁶	-	-	-	-
	20%	5.6	22.4	0.28	1.12	39.7	9.9	79.4	19.8
Combustion	30%	8.4	19.6	0.42	0.98	26.5	11.3	53.0	22.6
Modification	40%	11.2	16.8	0.56	0.84	19.8	13.2	39.6	26.4
	50%	14.0	14.0	0.70	0.70	15.9	15.9	31.8	31.8

¹Range in NO_x reduction relative to uncontrolled emissions.

²C = Controlled

³E = Emitted

⁴Approximate range in combustion modification costs from Tables 3-13 and 3-14, \$1970-1973.

Overfire air may be less than these costs, while water injection may exceed these costs depending on full price.

⁵28 = 18 (NO₂)/(NO)

⁶1.4 = 28 lbs NO₂/ton 20 X 10⁶Btu/ton.

Table 6-17. Range in Preliminary Costs per Ton for NO_x Control by Postcombustion Catalytic Methods

Control Method	%NO _x Reduction ¹	lbs NO ₂ /ton coal		lbs NO ₂ /10 ⁶ Btu		\$ /ton NO ₂			
		C ²	E ³	C ²	E ³	0.5 mills/Kwh ⁴		1.5 mills/Kwh ⁴	
Uncontrolled	0%	0	28 ⁵	0	1.46	-	-	-	-
	80%	22.4	5.6	1.12	0.28	99	397	297	1190
Postcombustion	85%	23.8	4.2	1.19	0.21	93	529	279	1590
Catalysts	90%	25.2	2.8	1.26	0.14	88	794	264	2380
	95%	26.6	1.4	1.33	0.07	84	1590	252	4770

¹Range in NO_x reduction relative to uncontrolled emissions.

²C = Controlled.

³E = Emitted.

⁴Approximate range in postcombustion catalytic control costs from Table 3.5-15, \$1973.

⁵28 = 18 (NO₂)/(NO).

⁶1.4 = 28 lbs NO₂/ton 20 X 10⁶Btu/ton.

6.3 PARTICULATE CONTROL

The reduction of particulate emissions is a significant aspect of the air pollution control industry. Particulate control is especially significant for coal use, which has accounts for as much as 90 percent of the total particulate emissions from stationary combustion sources (77, p.8,119). As much as 25 percent of all man-made particulate emissions have been caused by electric power generation, mostly from the use of coal. Recently, particulate emissions from stationary source fuel combustion have decreased, due to the commercialization of many types of particulate control techniques (118). However, with the projected increased utilization of coal, especially low sulfur coal (which tends to reduce collection efficiencies in electrostatic precipitators), to continue a decreasing emission trend will require increased investments and expansion of the particulate control industry.

This section discusses particulate control technologies with particular emphasis on particulates emitted from coal-fired steam-electric power plants. These technologies include mechanical devices such as centrifugal collectors, wet collectors, the electrostatic precipitator, and fabric filtration or baghouses. This section includes a brief review of the method of collection and status of each of these technologies. In addition particular operating conditions and constraints are outlined. The section is concluded with summary cost estimates for each method. Mathematical models for the cost and operation of particulate control technologies are published elsewhere (see reference 8 in Chapter 1).

Mechanical Collectors (gravitational, centrifugal)

Mechanical particulate collection includes settling chambers and dry centrifugal collectors or cyclones (28). These devices are simple in design and operation but have low collection efficiencies, especially for fine particulates. Typical fractional efficiency data with particle size is shown in Table 6-18 (77, 85).

The principle of the settling chamber is to decrease the gas velocity, by volume expansion, so that dust particles will settle out due to gravitational forces. Because of space limitations, settling chambers are usually limited to particles larger than 43 microns (325 mesh). Therefore, this method is not significantly used in the utility industry for any purpose except gross particulate removal.

Dry centrifugal collectors are devices that utilize the centrifugal force caused by spinning gases to separate particulate matter. These collectors are often called cyclones and may be designed for removal efficiencies between 50 and 99 percent, depending on particle size. A large-diameter conventional cyclone may provide a high collection efficiency (95-99%) for particles from 40 to 50 microns with a cut size of about 8 microns (78). High efficiency cyclones have small capacities but can remove 95-99% of the particles from 15 to 20 microns with a cut size of about 3 microns. Most centrifugal collectors have less than 50% removal efficiency for particles less than 5 microns.

A typical fly ash particle size distribution for pulverized fuel furnaces has a cut size of from 10-15 microns (79, p. 354), so that overall collection efficiency is limited (see Table 6-18).

Cyclones are often installed in series or parallel to increase the overall efficiency. Also they are sometimes used in tandem with more advanced removal methods such as electrostatic precipitation, but the combustion may not be cost effective as the cyclone may decrease the effectiveness of the preparation. The removal efficiency of a cyclone depends on the pressure drop between the inlet and outlet. This is influenced by particle size and density, so that ash content of the coal and thus dust loading affects removal efficiency; removal efficiency tends to increase with increased loads.

Wet Collectors

This type of technology is similar to flue gas desulfurization methods as discussed in this chapter above. The theory of wet collection includes two basic mechanisms (1) "conditioning" of particles to increase their effective diameter enabling more efficient collection and (2) trapping particles in a liquid film and washing them away thus minimizing reentrainment. These basic mechanisms are accomplished by bringing particulate matter into contact with liquid droplets as a result of interception, gravitational forces, impingement, diffusion, electrostatic forces and thermal gradients (77, p. 51).

Equipment design includes variations on spray chambers and towers, venturies, packed beds and centrifuges. Most of these methods have been successfully applied for over 50 years, with fundamental theoretical studies being conducted in the 1930's (80, p. 377). The Venturi scrubber was first patented in 1925. Today the packed bed, often referred to as a turbulent contact absorber (TCA scrubber), and the venturi scrubber are commonly used, with emphasis on the control of fine particulates (36, 81-84).

Data on the particulate removal efficiency of wet collectors is limited, although typical data is shown in Table 6-19. Some recent test data for fine particles are shown in Tables 6-20 and 6-21. It is generally believed that wet collection devices will remove significant amounts of both sulfur oxides and particulate matter from flue gases although operation and reliability problems may be significant when this is attempted (81, 95).

Electrostatic Precipitator

The high-voltage electrostatic precipitator is the most common type of particulate collector currently in use. For many existing operations this technology has been the only proven high-efficiency control device available. Its principle of operation is based on three steps (1) electrical charging of the suspended particulate matter (2) collection of the charged particulate matter on a grounded surface and (3) removal of the particulate matter and disposal. Suspended

Table 6-18. Typical Fractional Efficiency Data for Cyclones

Particle Diameter (microns)	Collection Efficiency	
	Medium Efficiency %	High Efficiency %
50	90	95
40	85	93
20	60	90
10	30	60
5	5	10

Source: Reference 85, Figure 15.

Table 6-19. Typical Fractional Efficiency Data for Wet Collectors

Particle Diameter (microns)	Collection Efficiency	
	Impingement Scrubber %	Venturi Scrubber %
10	99.99	99.99
5	96.0	99.0
2	92.0	95.0
1	90.0	94.0

Source: Reference 18, Figure 10.

Table 6-20. Fine Particle Fractional Efficiency for a TCA Scrubber

Pressure Drop (inches of H ₂)	<u>Percent Collected</u>		
	9.7-9.9	7.4-7.7	5.5-5.7
<u>Particle Size (microns)</u>			
1.73	99.6	99.6	98.1
0.99	99.5	95.3	90.3
0.65	92.9	92.7	85.4
0.29	95.0	92.8	73.6
0.11	94.6	92.5	71.0

Source: EPA, reference 36.

Table 6-21. Fine Particle Fractional Efficiency Data for a Venturi Scrubber*

<u>Particle Size (Microns)</u>	<u>Percent Collected %</u>
1.73	94
0.99	92
0.65	81
0.29	29
0.11	0

Source: EPA, reference 36.

*pressure drop = 9 in. H₂O

particulate matter in the flue gases is charged either by frictional forces, flame ionization or by passing through a high-voltage corona. The charged particles then migrate in an imposed electric field toward a grounded collecting surface where they are removed. Physical removal is accomplished by vibrating or rapping the electrodes allowing the collected material to fall into hoppers for final disposal. Summaries of the theory of electrostatic precipitation are numerous (e.g., 28, 79, 80).

The basic principles for using electrostatic forces to separate particles in suspended gases were known before the 18th century and were further developed by serious experimentation in the 19th century (80, p. 281). However, engineering and commercial feasibility in the air pollution control industry using electrostatic precipitation was not established until the early 1900's by Cottrell and others (87). The Cottrell process was rapidly commercialized so that by 1920, electrical precipitation was well established and in wide use in heavy industry. Today, the major application for this technology is in the collection of fly ash in flue gas from utility and commercial boiler operations. Currently this amounts to over 75% of the total in terms of volume of gas treated. Because of increased public awareness and environmental emission regulations, the growth in installed precipitator capacity is now increasing at an exponential rate as shown in Table 6-22. In addition, significant increases in collection efficiency have been noticed over the last 25 years, increasing from an average of about 95% to above 99% since 1950. This is significant when it is realized that a precipitator designed for 99% efficiency is at least two to three times the size of one for 90% efficiency. Typical fractional efficiency data for electrostatic precipitators is shown in Table 6-23, while recent test data for fine particle collection is shown in Table 6-24.

Precipitator Technology. Two major high-voltage electrostatic precipitator configurations are used: the flat surface and tube types. In the first, particles are collected on flat surfaces spaced 6 to 12 inches apart with a high-voltage wire or rod discharge electrode between them. In the tube types, the collection surfaces are cylindrical with the discharge electrode centered along the longitudinal axis. In an operating precipitator there are many of these basic units all acting in parallel. Variations on the design are basically geometrical in nature or include modifications to a standard power supply and electrical control configuration (77).

Recently, submicron particle collection has become especially important because these particles account for most of the reduced visibility caused by stack emissions, and may also be injurious to health. This has led to larger fly ash precipitators because of the increased efficiencies required, which has substantially increased costs. Precipitator design is now as nearly important as the production equipment itself, especially for fine particle collection. Much cheaper mechanical methods can be used for particle sizes above a few microns as discussed above. While both theory and practice show that particle collection rate decreases with particle size, in some

cases it is found to reach a minimum for particles of a few tenths micron diameter and then to increase for superfine particles (88). This is shown in Table 624. The electrical process has the inherent capability of capturing fine particulates with relatively low energy and small pressure drop through the gas cleaning system.

Precipitator Operation, Problems and Solutions. The practice of electrostatic precipitation is by no means a pure science. Although the fundamental physical principles are well known, wide variations are observed in practice, especially for changing coal characteristics in utility-scale power plants. There are established schools based on empirical knowledge only. Recently, theoretical techniques have been advanced by the use of mathematical models for precipitator design and performance analysis (89-92).

Operating experience has shown that problems of some magnitude are encountered in many precipitators. These problems fall into three basic categories: fundamental, mechanical and operational. Fundamental problems include high resistivity particles, reentrainment of collected particles, poor gas flow and insufficient particle charging. Mechanical problems are most commonly due to poor electrode alignment, breakage of equipment and air leakage. While operational problems encountered include electrical overloading, excessive dust collection and failure to service full hoppers.

High resistivity is an acute current problem because of the increased use of low-sulfur coals. Particles that bear a high concentration of sulfur-related ionic compounds tend to build up a charge at a fast rate (low resistivity) and are thus collected efficiently. Low-sulfur coals tend to cause high-resistivity fly ash which can be partly overcome by conditioning with SO_3 , sodium compounds or ammonia prior to the precipitator (93, p. 106, 152, 156). Fly-ash resistivity is also dependent on flue gas temperature, so that low resistivities are encountered at either high (600-800°F) or low (220-230°F) temperatures. Greater resistivity changes are evident at high temperatures (79, p. 361).

Precipitator Future. The current market for electrostatic precipitators is rapidly expanding. This is primarily due to air quality standards and the increasing use of coal to produce electricity. The high fly-ash resistivity associated with low-sulfur coals is causing a trend toward the use of "hot-side" precipitators. Wet precipitator systems are under investigation (94) and much activity is focused on the collection of submicron particles (93). There are many existing units which operate on high-sulfur coals or on the "cold side". Therefore, much of the industry will be concerned with retrofitting and the use of fly ash conditioning and other techniques.

Fabric Filter (Baghouse)

This particulate removal technique in general is quite old having a long commercial history in industry. However, it has only recently been applied in any commercial manner to the removal of fly ash at

Table 6-22. Recent Trends in the Electrostatic Precipitator Industry

<u>Year</u>	<u>Approximate Installed Capacity (10⁶ ACFM)</u>	<u>Annual Sales (\$10⁶/year)</u>
1966	450	40
1968	575	45
1970	700	60
1972	800	90
1974 (est)	900-1000	200-300

Source: Reference 87.

Table 6-23. Typical Fractional Efficiency Data for Electrostatic Precipitators

<u>Particle Diameter (microns)</u>	<u>Collection Efficiency</u>		
	<u>Low Efficiency %</u>	<u>Medium Efficiency %</u>	<u>High Efficiency %</u>
1.0	75	85	98
0.5	60	82	97
0.1	30	65	95
0.05	25	60	93
0.01	5	40	90

Source: Reference 85, Figure 17 (based on extrapolated data). See also Reference 120.

Table 6-24. Fine Particle Fractional Efficiency Data for Electrostatic Precipitators

Particle Diameter (microns)	<u>Collection Efficiency</u>		
	<u>Hot Side</u> %	<u>Cold Side</u> %	<u>Wet</u> %
5	99.9-99.98	99.5-99.8	98-95.5
1.0	96-99	92-96	98-99
0.5	90-98	92-96	98-99
0.1	99-99.5	95-98	96-99

Source: Estimated from Figures 7, 11 and 12, pp. 91, 95 and 96, reference 93.

utility-scale power plants (100, 101). The fabric filter is capable of collecting fine particulate material with considerable efficiency as shown by the typical fractional efficiency data in Table 6-25.

The basic principle of operation appears simple. Particulate matter collects on the up-stream side of the fabric, while clean air passes through to the down-stream side. The actual physical mechanism is quite complicated involving a combination of direct particle interception, inertial impaction, diffusion, electrostatic attraction and gravitational settling. The inter-fiber spaces of the clean cloth are usually much larger than the majority of particles being collected so that gas cleaning initially results by adhesive forces. Later a filter cake is formed which acts as the filter medium until the fabric is cleaned by mechanical or other means. The removal efficiency of a fabric filter thus is a time dependent phenomenon.

Baghouse Technology. Fabric filters are usually tubular or flat and may number up to several thousand. The structure in which the bags hang is called a baghouse. Fabric filters have a wide range of application; approximately 80% of all manufacturing plants contain operations that produce dust and particles of such a size that use of a highly efficient collection device such as a baghouse is desirable (77, p. 104). General technological discussions are available (77) and the theory of operation has been summarized (28, 80). Currently many test programs are underway (101) and research and development is intensive (98), especially for fine particle collection (99). Several research efforts include mathematical modeling and computer simulation (98, 102).

Baghouse Operations. The commercial application of fabric filtration to control fossil-fueled boiler emissions is new. Until now, other emission control systems were chosen because baghouses had high costs compared to less efficient, but acceptable control methods. Also high flue gas pressures are required, problems of acid attack of fabric material are evident and bag life has been unacceptably short under utility-scale conditions (101). With the requirement of stricter particulate emission regulations baghouse systems now have a utility market and are a serious competitor to electrostatic precipitation and wet scrubbing. New materials such as woven fiberglass and Teflon can now provide the performance required on most boiler fly-ash removal applications. Bag failures are decreasing and consequently maintenance costs are being reduced. Also, newer materials are less prone to acid attack.

Fabric filters have the best potential application for controlling fine particle emissions; as shown in Table 6-26 the fractional efficiencies are relatively constant with decreasing particle diameter. No other technology has such a "flat" response.

The use of nahcolite ore and bag filters for simultaneous particulate and sulfur dioxide emission control has some particular promise (104). Recent tests have indicated more than 99% removal of particulates and greater than 70% removal of sulfur oxides using the process on coal-

Table 6-25. Typical Fractional Efficiency Data for Fabric Filtration

Source: Reference 85, Figure 17 (based on extrapolated data)

fired power plants (103). In addition the technical feasibility has been demonstrated for both bench and pilot plant studies. Nahcolite is an abundant material which is composed of from 70 to 90 percent sodium bicarbonate. The material is finely ground to 200 mesh and is used to precoat the bags. It is also directly injected into the gas stream. This is the only dry process capable of removing both particulates and sulfur oxides. Preliminary cost estimates have indicated that the process may be competitive with wet scrubbing.

Particulate Control Cost Summary

In general, the cost of controlling particulate emissions has been second order economic consideration with respect to the cost of sulfur oxide control. Large electrostatic precipitators and high efficiency baghouses have costs that approach the total annual operating cost of sulfur residual control technologies.

There are many sources of particulate control costs including industry and utility surveys (107, 108), cost accounting and estimating procedures (109, 110) and cost-effective analytic studies (111).

Mechanical Collectors. The annualized cost for mechanical collection of particulates is comparatively minor with respect to other control costs. Typical annual costs are shown in Table 6-27, where there is no evidence of an economy of scale. These costs correspond to 50-70% collection efficiency for large diameter particulates.

Wet Collectors. The annualized cost for typical low-capacity wet collectors is shown in Table 6-28. The cost increases significantly with collection efficiency and has a noticeable economy of scale. Wet collectors include low efficiency mechanical devices as well as high efficiency venturists.

Recent tests of a particulate scrubber (mobile-bed) on a full-scale utility boiler (150 Mw) have demonstrated a nominal 95% removal efficiency at a 1972-installed cost of \$29/Kw and an annual operating cost of about 0.5 mills/Kw-hr (75% availability). The removal efficiency was sensitive to particulate size (112). Other estimates have suggested a capital cost of \$21 to \$34 per kilowatt (\$1975) for a venturi scrubber (24, p. 3-16).

Electrostatic Precipitators. There is a significant amount of cost information available for electrostatic precipitator operations as this is the most common type of particulate control device. Fairly large differences have been founded between plants and even between units operating in the same plant (107). Maintenance costs appear to account for most of the difference.

Costs for a model 600 Mw power plant are shown in Table 6-29, while cost ranges for 30 TVA units are shown in Table 6-30. Although the cost range may be significant, the total annual cost for electrostatic precipitator operations has not been greater than approximately

Table 6-26. Baghouse Fractional Efficiency Data for Coal-Fired Industrial Boilers (Air-to-Cloth Ratio = 6)

Particle Diameter (microns)	Removal Efficiency %
9.5	99.84%
6.0	99.74
4.0	99.78
2.8	99.69
1.75	98.03
0.9	99.21
0.54	99.16
0.36	96.88
0.36	99.98
Average Size	Average 99.51%

Source: Reference 97, p. 27.

Table 6-27. Typical Annualized Cost of Operation of Dry Centrifugal Collectors^(a) \$1968

Gas Volume (10 ³ ACFM)	Approximate Annualized Cost	
	\$10 ³	mills/Kw-hr ^(b)
50	6	0.041
100	12	0.041
500	60	0.041
1000	120	0.041

^aSource: NAPCA, reference 109, p. 171, Figure 6-9.

^bAssuming 3 ACFM/Kw and 8760 hrs/yr.

Table 6-28. Typical Annualized Cost of Operation of Wet Collectors with Collection Efficiency^(a) \$1968

Gas Volume (10 ³ ACFM)	Approximate Annualized Cost					
	<u>\$10³</u>	<u>75%</u> mills/Kw-hr	<u>\$10³</u>	<u>90%</u> mills/Kw-hr	<u>\$10³</u>	<u>95%</u> mills/Kw-hr
5	1.5	0.10	2.5	0.17	7.5	0.51
10	2.0	0.07	5.0	0.17	12	0.41
50	9.0	0.006	20	0.14	60	0.41
100	18	0.06	40	0.14	120	0.41

^aSource: NAPCA, reference 109, p. 172, Figure 6-12.

^bAssuming 3 ACFM/Kw and 8760 hrs/year.

Table 6-29. Electrostatic Precipitator Control Costs for a Model
600 Mw Plant \$1970

	<u>Cost Range</u>	
	<u>Low</u>	<u>High</u>
Electrostatic Precipitator (2 units, 98% efficiency)	\$620,000 (\$1.03/Kw)	\$1,850,000 (\$3.08/Kw)
Fly Ash Disposal Investment	\$180,000	\$ 600,000
Fixed charges	96,000	294,000
Operation and maintenance	7,800	33,000
Fly ash disposal	27,000	52,500
Total		
\$/year	130,000	379,500
mills/Kw-hr	0.03	0.09

Source: Reference 108, Table VI, p. 288.

Table 6-30. Cost Range for Thirty TVA Electrostatic Precipitator
Units^(a) \$1972

	<u>Low</u>		<u>High</u>	
	<u>\$/cfm-yr</u>	<u>mills/Kw-hr^b</u>	<u>\$/cfm-yr</u>	<u>mills/Kwhr</u>
Annualized Capital Cost	0.063	0.022	0.289	0.099
Total Operating Cost	0.007	0.002	0.135	0.046
Total Maintenance Cost	0.090	0.031	0.452	0.155
Total Cost	0.178	0.061	0.643	0.220

^aSource: Reference 107, p. 348, Table X.

^bAssuming 3 ACFM/Kw and 8760 hrs/yr.

5% of the cost of power production (typical power production costs circa 1970 for a 600 Mw coal-fired power plant were around 4-5 mills/KW-hr, see reference 108, p. 288). Capital cost estimates in 1975 for large high efficiency precipitators from \$20 to \$40 per kilowatt (24, p. 3-16), so that control costs are increasing.

With the increased use of low sulfur coals, electrostatic precipitator removal efficiencies have been affected. As discussed above, this problem has been solved by conditioning the flue gas with SO_3 , sodium or ammonia.

The cost of flue gas conditioning is very low. Recent tests by Pennsylvania Power and Light (113) on two 750 Mw units have indicated costs of about 0.30/Kw (\$1974) for capital-related items and less than 0.07 mills/Kw-hr for operation and maintenance (mostly chemicals). Australian experience has been similar: 0.04-0.09 \$/Kw capital and 0.008-0.04 mills/Kw-hr operating cost (114). Flue gas conditioning may restore removal efficiencies to their previous levels, so that the effect of using low sulfur coals in existing boilers with electrostatic precipitators can be reduced at a relatively small cost.

Fabric Filtration (Baghouse). Cost data for baghouses is not as available as that for other particulate control technologies, and little actual operating data has been collected for utility-scale coal-fired power plants. Some test data has demonstrated a 99.9% or better removal efficiency at a capital cost of \$87/Kw (retrofit) with an annual operation and maintenance cost of about 1.5 mills/Kw-hr (115). Typical new baghouses (300-400 Mw) may be installed for about \$40/Kw (+\$10/Kw) with an annual operation and maintenance cost of about 0.3-0.5 mills/Kw-hr (116). Removal efficiencies for new fabric filters may be as high as 99.95%. The estimated capital cost for a small baghouse is shown in Table 6-31.

As discussed above, baghouses may be used to remove sulfur dioxide as well as particulates by using nahcolite injection (103). The cost of this process has recently been compared with the cost for the wet limestone scrubbing process as shown in Table 6-32. This data indicates that simultaneous removal of particulates and sulfur oxides using baghouses may be cost effective, although only 70% of the sulfur oxides were removed. Over 90% SO_2 removal is possible using wet scrubbers.

Summary. The cost of particulate control is in general less than that for the removal of sulfur oxides. However, the cost for new high efficiency devices is approaching the cost for sulfur control. Large-scale high-efficiency particulate control using either wet scrubbers, electrostatic precipitators or baghouses have been available at about \$20-\$40 (\$1975) per kilowatt for new facilities. Annual operation and maintenance costs in the early 1970 is varied up to about 0.5 mills/Kw-hr. Currently, particulate control costs are increasing. Capital costs may approach \$100/Kw (\$1977) (121), and annual costs is exemplified by Table 6-321, may exceed 4 mill/Kwhr.

Table 6-31. Estimated Cost of the NUCLA Baghouse Installation^a
(October, 1974)

<u>Item</u>	<u>Cost</u>	<u>Percent</u>
Baghouse Collectors	\$ 631,168	24%
Ash System	86,332	3
Miscellaneous Equipment and Materials	280,083	11
General Construction	1,193,080	46
Engineering (consultant)	294,383	11
Management	<u>120,000</u>	<u>5</u>
	\$2,605,046 ^b	100%

Source: GCA Corporation, reference 96.

^a13 Mw coal-fired power plant, 15,500 lbs of coal per hour; about 99.8% particulate removal.

^bAbout \$10/ACFM.

Table 6-32. Summary Cost Estimates for SO₂ and Particulate Removal at Two Power Plants^a (April, \$1973)

	Southwest Power Plant (one 800 Mw unit)		Midwest Power Plant (two 840 Mw units)	
	<u>Nahcolite Injection^b</u>	<u>Wet Limestone Scrubbing^c</u>	<u>Nahcolite Injection</u>	<u>Wet Limestone Scrubbing</u>
Capital Cost				
\$	15,800,000	25,800,000	45,200,000	66,700,000
\$/Kw	19.8	32.2	26.9	39.7
Annual Cost				
\$/year	8,420,000	7,790,000	35,600,000	27,100,000
mills/kwhr	1.77	1.64	3.72	2.83

^aSource: Reference 103, Table IX, p. 1251.

^b99% particulate removal and 70% SO₂ removal.

^cAssuming 90% SO₂ removal (not stated).

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62. 42, p. 5-57.
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