Coal-Fired Power-Plant Capital Cost Estimates

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Prepared by
Bechtel Power Corporation
San Francisco, California

ELECTRIC POWER RESEARCH INSTITUTE

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Prepared by

BECHTEL POWER CORPORATION
50 Beale Street
San Francisco, California 94119

Project Manager
W. Dunlop

Principal Investigator
R. A. Holstein

Prepared for

Electric Power Research Institute
3412 Hillview Avenue
Palo Alto, California 94304

EPRI Project Manager
R. A. Loth

R&D Planning and Evaluation

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ABSTRACT

Conceptual designs and order-of-magnitude capital cost estimates have been prepared for typical 1000-MW coal-fired power plants. These subcritical plants will provide high efficiency in base load operation without excessive efficiency loss in cycling operation. In addition, an alternative supercritical design and a cost estimate were developed for each of the plants for maximum efficiency at 80-100% of design capacity.

The power plants will be located in 13 representative regions of the United States and will be fueled by coal typically available in each region. In two locations, alternate coals are available and plants have been designed and estimated for both coals resulting in a total of 15 power plants. The capital cost estimates are at mid-1978 price level with no escalation and are based on the contractor's current construction projects. Conservative estimating parameters have been used to ensure their suitability as planning tools for utility companies.

A flue gas desulfurization (FGD) system has been included for each plant to reflect the requirements of the promulgated New Source Performance Standards (NSPS) for sulfur dioxide (SO_2) emissions. The estimated costs of the FGD facilities range from 74 to 169 $/kW depending on the coal characteristics and the location of the plant.

The estimated total capital requirements for twin 500-MW units vary from 808 $/kW for a southeastern plant burning bituminous Kentucky coal to 990 $/kW for a remote western plant burning subbituminous Wyoming coal.

EPRI PERSPECTIVE

PROJECT DESCRIPTION

In setting priorities and allocating funds for R&D of new or improved power generation technologies, EPRI staff considers the potential benefits from reduced cost and/or improved performance of these technologies. Estimates of cost and performance are prepared by engineering firms under contract to EPRI and are based on premises established by EPRI to ensure consistency of the data. This final report under TPS 78-810, entitled Coal-Fired Power Plant Capital Cost Estimates, provides cost and performance data for coal-fired power plants of the type and size most frequently ordered by electric utilities in the past decade. The data in this report will serve as a benchmark for evaluation of new or improved power generation technologies. The present report is an update and expansion of a previous report of the same title (EPRI Final Report AF-342) published in January 1977.

PROJECT OBJECTIVE

The objective of this project was to develop consistent and representative cost and performance data for current-technology coal-fired power plants that may be used in R&D planning and assessment.

PROJECT RESULTS

Conceptual designs and capital cost estimates were prepared for 15 power plants located in 13 representative regions of the United States and fueled by coal typically available in each region. Each plant, consisting of two 500-MW(e) units, was designed to comply with all applicable federal, state, and local regulations in effect on July 1, 1979. Cost and performance estimates were made for both subcritical and supercritical steam plants.

Estimated total capital requirements for the subcritical plants ranged from $808/kW (mid-1978 dollars) for a southeastern plant burning bituminous Kentucky coal to $990/kW for a remote western plant burning subbituminous Wyoming coal. Estimated capital requirements for the supercritical plants were not significantly different from those for the subcritical plants, whereas fuel consumption was estimated to be about 4% lower.

An attempt was made to compare the cost estimates prepared in the present study with cost data published by utilities for plants in various stages of planning or construction. Data for a large number of plants with actual or planned completion dates between 1978 and 1985 were reviewed. It was found that the range of capital costs (in dollars/kW) was too broad to permit a meaningful comparison of individual plant costs. The ratio of highest-to-lowest cost ranged from about two to more than three for plants completed or to be completed in the same year. Many factors that affect capital cost, e.g., unit size, coal quality, site features, regulatory requirements, labor productivity and cost, project scope, etc., may have contributed to these wide variations, but funding limitations for the present study did not permit a detailed investigation of these factors. It is clear, however, that the cost data presented in this report should not be compared with data from other sources unless all factors that significantly affect cost have been identified and included on a consistent basis.

René A. Loth
R&D Planning and Evaluation

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Section 1

INTRODUCTION

Electric Power Research Institute (EPRI) of Palo Alto, CA, has engaged Bechtel National Inc. of San Francisco to prepare capital cost estimates for coal-fired power plants in various locations of the United States. This study is an update of an earlier report performed by Bechtel under EPRI contract. The report was published in January 1977 under the title of "Coal-Fired Power Plant Capital Cost Estimates (EPRI AF-342)".

Plant net output would be 1000 MW, utilizing two 500-MW units.

This study is part of a broad EPRI effort to acquire consistent cost and performance information on current and future power generation technologies for the purpose of research and development planning and assessment. EPRI will not only use this report as a reference document but to also improve industry and public understanding of present and future electric power plant costs by widespread publication.

1.1 PLANT LOCATIONS

The earlier study (EPRI AF-342) developed capital cost estimates for four locations with six power plant design cases. This report updates and expands the earlier study to develop estimates for 13 locations representing all regions of the United States. Two of the 13 locations would use coal from two different sources resulting in 15 power plant design cases.

The 15 plants established for the study are listed in Table 1-1, together with their coal and the New Source Performance Standards (NSPS) emission standards.

1.2 COAL SOURCES

Plants at the established locations will be designed to burn coal typically available in the region with delivery by the unit train method. At two locations, where alternate sources of coal are available, capital cost estimates have been prepared for the same plant burning both types of coals.

Selected coal types are listed in Table 1-1.

Table 1-1

PLANT LOCATIONS

	Plant Location	Type of Coal	Emission Standards		
1.	East Central - Wisconsin	Bituminous	1979	EPA	NSPS
2.	East Central - Wisconsin	Subbituminous	1979	EPA	NSPS
3.	West - Oregon	Subbituminous	1979	EPA	NSPS
4.	Northeast - Pennsylvania	Bituminous	1979	EPA	NSPS
5.	Southeast - Georgia	Bituminous	1979	EPA	NSPS
6.	West - Utah	Bituminous	1979	EPA	NSPS
7.	South Central - Texas	Subbituminous	1979	EPA	NSPS
8.	South Central - Texas	Lignite	1979	EPA	NSPS
9.	South Central - Arkansas	Lignite	1979	EPA	NSPS
10.	West Central - Iowa	Bituminous	1979	EPA	NSPS
11.	West Central - N. Dakota	Lignite	1979	EPA	NSPS
12.	Northeast - Massachusetts	Bituminous	1979	EPA	NSPS
13.	Southeast - Florida	Bituminous	1979	EPA	NSPS
14.	West - New Mexico	Bituminous	1979	EPA	NSPS
15.	East Central - Illinois	Bituminous	1979	EPA	NSPS

1.3 DESIGN CONDITIONS

Each of the 15 base case designs will be for high efficiency subcritical base load units with cycling capabilities. During the day, the plants will operate between 80-100% capacity and during the night at minimum capacity. The plants will be shutdown on the weekends.

An alternate design case was prepared for each of the 15 base case designs employing a supercritical design with maximum efficiency at 80-100% capacity and lesser efficiency at lower loads.

Processes and equipment included in the plant designs are restricted to those demonstrated in commercial plant operations. Due to this restriction, only limestone and lime slurry FGD processes were included in this study.

1.4 EMISSION CONTROL REQUIREMENTS

Each base design case and alternate design case were prepared to meet the 1979 promulgated NSPS for particulate, SO_2 and NO_x emissions. Each location was examined for the state and local air quality control requirements.

1.5 CAPITAL COST ESTIMATES

The capital cost estimates are based on Bechtel Power Corporation's experience and were developed in accordance with EPRI's economic premises.

The estimates were prepared at mid-1978 price level with no escalation reflecting a commercial operation date of July 1, 1979 for Unit 1 and July 1, 1980 for Unit 2.

Cost figures for all cases are presented at the TOTAL CAPITAL REQUIREMENT level including:

- Total field cost.
- Engineering and other services.
- Contingencies.
- Owner's cost.

Section 2

SUMMARY

2.1 EMISSION STANDARDS

The emission regulations confronting all new generating facilities today are those promulgated by EPA in June 1979 as New Source Performance Standards.

The major differences between the current (June 1979) and the originally proposed (September 1978) NSPS are those relating to SO_2 emission control:

- For high sulfur coal, an increase in overall sulfur removal from 85 to 90% with a maximum emission of 1.2 lb SO_2/M Btu boiler heat input. This is accompanied by an increase in the averaging time for compliance from 24 hours to 30 days.
- For low sulfur coal, a decrease in the overall sulfur removal from 85 to 70% accompanied by the above increase in averaging time.
- For intermediate sulfur coal, a sliding scale removal requirement ranging from 70% to 90% with a maximum emission of 0.6 lb SO_2/M Btu boiler heat input.

Of the above, only the change in low sulfur coal SO_2 removal requirement significantly affects capital cost.

2.2 SITE SELECTION AND COAL SOURCES

Site selection investigation and environmental standards discussions have been stressed more heavily due to the many varied considerations required for approval of each specific plant site.

The major factors considered were:

- Engineering economics
- Environmental regulations

A plant site in the west can be located either within commuting distance of urban centers or, more likely, at a location remote from population centers. The remote locations have a significant impact on labor costs during plant construction and estimates have been prepared for two such locations. In the other regions, plants have been located in suburban areas.

The various coal characteristics can have major cost impact on the:

- Boiler.
- FGD system.
- Precipitator.
- Coal and ash-handling.
- Plant arrangement.

Boiler material alone can vary from 69.0 million dollars (Georgia plant) to 72.0 million dollars (Illinois plant) for the 2x500-MW units due to coal heating value. The Georgia plant burning bituminous Kentucky coal with a high heating value will be a smaller boiler costing less than the Illinois boiler burning bituminous Illinois coal with a lower heating value.

2.3 PLANT ARRANGEMENT AND DESIGN

The plant arrangement and design is described in detail in Section 5.1 with Plant No. 1 as the base plant and is believed to be functional, practical, and economical. This arrangement is common to the 15 plants studied with minor variations to adapt to the particular type of coal and site.

High efficiency electrostatic precipitators (ESPs) have been selected for fly ash particulate removal, followed by a spray tower absorber FGD facility for SO_2 removal. For an actual future plant, a different type of absorber, or an absorber combining both particulate removal and SO_2 removal, might be more advantageous for the Owner.

The selected FGD systems utilize nonrecovery lime and limestone slurry scrubbing processes. As discussed in Section 5.0.5, lime has been chosen as the absorbent alkali for plants burning the low sulfur western coal and limestone for the higher sulfur eastern coal. Considerable detail is provided on these systems since FGD system costs are 10-20% of the total plant cost.

2.4 CAPITAL COST ESTIMATES

The capital cost estimates for the 15 plants are at the July 1, 1978 price level. They are presented in detail in Section 6 and summarized in Table 2-1 below:

Table 2-1

SUMMARY OF CAPITAL COSTS

Plant	Plant Location	Type of Coal	$/kW for 2-500 MW Net With FGD	$/kW for 2-500 MW Net W/O FGD
1	East Central-Wisconsin	Bituminous	876	725
2	East Central-Wisconsin	Subbituminous	876	777
3	West-Oregon	Subbituminous	990	888
4	Northeast-Pennsylvania	Bituminous	919	776
5	Southeast-Georgia	Bituminous	808	666
6	West-Utah	Bituminous	977	876
7	South Central-Texas	Subbituminous	869	775
8	South Central-Texas	Lignite	907	797
9	South Central-Arkansas	Lignite	963	863
10	West Central-Iowa	Bituminous	968	762
11	West Central-N. Dakota	Lignite	881	791
12	Northeast-Massachusetts	Bituminous	904	800
13	Southeast-Florida	Bituminous	840	733
14	West-New Mexico	Bituminous	897	801
15	East Central-Illinois	Bituminous	876	732

Capital costs for the above plants range from 808 to 990 $/kW.

The western plant in the remote Oregon location is estimated to cost 23% more than the southeastern plant situated in Georgia. The capital costs for the other plants are between the Oregon and the Georgia plants.

The estimated costs of the base plants and alternative plants have been factored from the base plants using data in Bechtel's historical files.

The cost differences can be related to many factors and those having the major effect on the costs are summarized below:

- Labor and related items

- Equipment
- Site conditions
- Freight
- Construction schedule (climate)

A short summary of a few findings follows for each case:

Plant No. 1 (Wisconsin)

The capital cost estimate for Plant No. 1, the base plant burning Illinois coal requiring FGD, is $875,600,000. The estimate is subject to the qualifications stated in Section 6 and reflects the costs of labor, labor-related factors, and wage rates expected at a location within commuting distance of a populated center.

Plant No. 2 (Wisconsin)

The estimate for Plant No. 2, which would be at the same location as Plant No. 1 but burning Powder River coal instead of Illinois coal, is $875,500,000 with FGD. The higher cost resulting from the use of the low Btu coal is offset by the lower FGD system cost due to the use of low sulfur coal. As shown in Table 6-1, the steam generators, electrostatic precipitators, and related items cost more and the FGD costs less.

Plant No. 3 (Oregon)

Plant No. 3 is the same as Plant No. 2 but at a western site in a remote area. It is estimated to cost 13% more than Plant No. 1. Approximately 7% of the higher costs are for labor incentives. These incentives are estimated to add 15% to all field labor-related costs.

Plant No. 4 (Pennsylvania)

Plant No. 4 is similar to Plant No. 1 but located at a different site and burning a different eastern coal. It is estimated to cost 5% more as a net result of lower material costs but higher labor costs.

Plant No. 5 (Georgia)

Plant No. 5 is estimated to cost 8% less than Plant No. 1. At its location, labor costs are estimated to be 20% lower than at Plant No. 1. It is fired with the Kentucky coal which has a 20% higher Btu/lb content and therefore consumes less coal requiring smaller equipment than Plant No. 1.

Plant No. 6 (Utah)

Plant No. 6 is located at an elevation of 4700 ft, which causes increased steam generation cost resulting from the handling of large volumes of low density air and flue gas. In addition, the high ash content and ash composition of the Utah coal requires increased precipitator capacity. Also, labor and material costs are higher in Utah resulting in a 12% increase in estimated costs over Plant No. 1.

Plant No. 7 (Texas)

Plant No. 7 is estimated to cost about 1% less than Plant No. 1. The lower heating value Montana coal requires additional precipitator capacity which is offest by lower FGD cost.

Plant No. 8 (Texas)

Plant No. 8, in the same location as Plant No. 7 but burning Texas lignite, will cost about 4% more than Plant No. 1. The lignite has a lower heating value than the coal of Plant 7 and requires increased boiler size and enlarged capacity of the coal- and ash-handling facilities.

Plant No. 9 (Arkansas)

Plant No. 9 is fueled by lignite which has the lowest heating value of all of the coals selected and with a high ash content. Also, the plant site will require costly site development resulting in a 10% increase in the estimated cost over Plant No. 1.

Plant No. 10 (Iowa)

Plant No. 10 is estimated to cost 10% more than Plant No. 1. The Iowa coal has a lower Btu value than the Illinois coal causing an increased steam generation cost. Additional site development work accounts for the remainder of the cost increase.

Plant No. 11 (North Dakota)

Plant No. 11 will be another lignite-burning plant similar to Plant Nos. 8 and 9 but located in North Dakota. The Dakota lignite has a low heating value compared with the Texas lignite but also has a lower ash content which would make it less costly than the other lignite plants. The estimated cost of Plant No. 11 is about 1% higher than Plant No. 1.

Plant No. 12 (Massachusetts)

Plant No. 12, in Massachusetts, will burn a bituminous coal similar to the Illinois coal of Plant No. 1 but which has an ash which is more difficult to remove. This results in increased electrostatic precipitator costs. Construction labor and material prices are also higher at this site, resulting in the estimated cost of Plant No. 12 being 3% above Plant No. 1.

Plant No. 13 (Florida)

Plant No. 13 will be located in Florida and will be fueled by a bituminous coal similar to the Illinois coal except for a much higher ash content. The increased cost of the electrostatic precipitators will be offset by the lower construction costs and material prices resulting in the plant costs being 4% lower than for Plant No. 1.

Plant No. 14 (New Mexico)

Plant No. 14 is estimated to cost about 2% more than Plant No. 1. The ash composition of the coal will necessitate increasing the electrostatic precipitator capacity and the low heating value will require additional steam generation.

Plant No. 15 (Illinois)

Plant No. 15 has many similarities to Plant No. 1 and the estimated cost is the same.

Section 3

EMISSION STANDARDS AND REGULATIONS

3.1 EMISSION CONTROL REQUIREMENTS

In June 1979, the Environmental Protection Agency (EPA) promulgated the final rules for NSPS of electric utility steam generating units. These standards of performance limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units capable of combusting more than 73-MW heat input of fossil fuel. The standards described here are those relating to solid fuels.

The intended effect of these regulations is to use the best technological system of continuous emission reduction and to satisfy the requirements of the Clean Air Act Amendments of 1977. These standards apply for plants for which construction is commenced after September 18, 1978. Table 3-1 summarizes the 1979 standards.

The states are free to adopt their own emission control standards provided they comply with or are more stringent than those promulgated by the EPA. Table 3-2 shows the emission limits adopted by various states prior to the promulgation of the final rule for NSPS.

Proposed standards, also prior to the promulgation of the final NSPS, for the control of the effluents from steam power generating facilities are outlined in Table 3-3.

3.2 PARTICULATE EMISSION

The standard for particulate matter limits the emission to 0.03 lb/M Btu heat input and requires a 99% reduction in uncontrolled emissions for solid fuels. However, the percent reduction requirement is not controlling and compliance with the emission limit will ensure compliance with the 99% reduction requirement.

The 20% (6 minute average) opacity limit is to ensure proper operation and maintenance of the emission control system. If a facility complies with all applicable standards except opacity, the Owner may request a source-specific opacity limit for the facility involved.

Table 3-1

NEW SOURCE PERFORMANCE STANDARDS[1]

(Solid Fuels)

	Particulate	SO_x	NO_x
Reduction of uncontrolled emissions (%)	99+[2]	90-70[3][6]	65[2][3]
Maximum emission limits ($lb/10^6$ Btu)	0.03	1.2[3]	0.5-0.8[5]
Opacity	20%[4]		

---

(1) EPA final NSPS (June 1979).

(2) Percent reduction requirements are not controlling, compliance with emission limit will ensure compliance with percent reduction.

(3) Compliance is based on a 30-day rolling average.

(4) Averaging time is 6 minutes. Opacity limit is not controlling when all other regulations are complied with.

(5) Subbituminous coal = 0.5 lb/M Btu heat input
Any other solid fuel = 0.6 lb/M Btu heat input
Lignite coal = 0.8 (25% or more feed to a slag-tapping furnace by weight, of lignite mined in North or South Dakota or Montana)

No emission limitation if the fuel contains more than 25%, by weight, coal refuse.

(6) 90% reduction is required at all times except when emission is less than 0.6 lb/M Btu. When SO_2 emissions are less than 0.6 lb/M Btu heat input, a 70% reduction in potential emissions is required.

Table 3-2

SOLID FUEL EMISSION LIMITS FOR VARIOUS STATES IN THE U.S. [1][2][6]

	Florida	Georgia	Illinois	Mass.	N. Mex.	N. Dak.	Penn.	Texas	Wisconsin	EPA
Particulate Matter										
Emission (lb/106Btu)	0.1	0.1	0.1	0.1	0.05	0.1	0.1	0.3	0.15	0.03
Opacity (%)	20	20	20	20	-	20	20	20	20	20
Sulfur Dioxide										
Emission (lb/106Btu)	0.8	1.2	1.2	1.2	0.34	1.2	1.8[3]	3.0	1.2	1.2
Nitrogen Oxides										
Emission (lb/106Btu)	0.7	0.7	0.7	0.7	0.45	0.7[4]	-	[5]	0.7	0.5-0.8

(1) Four states - Arkansas, Iowa, Oregon, and Utah - have the same emission limits as the federal standards.

(2) Limits shown apply for general state regions. Certain air quality control regions within the state may require stricter limits.

(3) With 500 ppm limit.

(4) Except lignite.

(5) No general state NO_x emission limit. For Dallas-Fort Worth and the Houston-Galveston air quality control regions, the NO_x emissions are limited to 0.7 lb/M Btu for opposed-fired furnaces, 0.5 for front-fired, and 0.25 for tangential-fired furnaces.

(6) Proposed prior to the promulgation of the final rule for NSPS by EPA in June 1979.

TABLE 3-3

SUMMARY EFFLUENT GUIDELINES AND STANDARDS FOR STEAM POWER GENERATING CATEGORY

Source	Effluent Characteristic	Effluent Limitations* BPCTCA***	BATEA***	New Sources
Once-Through Cooling Water	Chlorine - Free Available	0.2(0.5 max)**	0.2(0.5 max)**	0.20(0.5 max)**
Cooling Tower Blowdown	Chlorine - Free Available	0.2(0.5 max)**	0.2(0.5 max)**	0.2(0.5 max)**
	Other Corrosion Inhibitors		Established on case-by-case basis	No detectable amount
	Chromium	--	0.2(0.2 max)	No detectable amount
	Zinc	--	1.0(1.0 max)	No detectable amount
	Phosphorous	--	5.0(5.0 max)	No detectable amount
	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Bottom Ash Transport	TSS***	30 (100 max)	30 (100 max)	30 (100 max)
	Oil & Grease	15 (20 max)	15 (20 max)	15 (20 max)
	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Fly Ash Transport	TSS	30 (100 max)	30 (100 max)	30 (100 max)
	Oil & Grease	15 (20 max)	15 (20 max)	15 (20 max)
	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Low Volume Wastes[1]	TSS	30 (100 max)	30 (100 max)	30 (100 max)
	Oil & Grease	15 (20 max)	15 (20 max)	15 (20 max)
	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Rainfall Runoff[3]	TSS	50	50	50
	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Transformers	Polychlorinated Biphenyls	No Discharge	No Discharge	No Discharge
Metal Cleaning Waste[2]	TSS	30 (100 max)	30 (100 max)	30 (100 max)
	Oil & Grease	15 (20 max)	15 (20 max)	15 (20 max)
	Copper, Total	1.0 (1.0 max)	1.0 (1.0 max)	1.0 (1.0 max)
	Iron, Total	1.0 (1.0 max)	1.0 (1.0 max)	1.0 (1.0 max)
	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0
Boiler Blowdown	TSS	30 (100 max)	30 (100 max)	30 (100 max)
	Oil & Grease	15 (20 max)	15 (20 max)	15 (20 max)
	Copper, Total	1.0 (1.0 max)	15 (20 max)	1.0 (1.0 max)
	Iron, Total	1.0 (1.0 max)	1.0 (1.0 max)	1.0 (1.0 max)
	pH	6.0 to 9.0	6.0 to 9.0	6.0 to 9.0

See Pg. 3-5 for Footnotes 1, 2, and 3.
See Pg. 3-5 for *, **, and ***.

TABLE 3-3

SUMMARY EFFLUENT GUIDELINES AND STANDARDS FOR
STEAM POWER GENERATING CATEGORY
(Continued)

NOTE:*

Numbers are concentrations, mg/l, except for pH values. Effluent limitations, except where otherwise indicated, are monthly averages of daily amounts, mg, to be determined by the concentrations shown and the flow of wastewater from the source in question. In some cases, there are limitations shown on the maximum amount for any day. Where wastewaters from one source with effluent limitations for a particular pollutant are combined with other wastewaters, the effluent limitation for the particular pollutant of the combined streams shall be the sum of the effluent limitations for each of the streams. However, the actual amount of the pollutant in a contributing stream will be used in place of the effluent limitation for those contributing streams where the actual amount of the pollutant is less than the effluent limitation for the contributing stream. The pH value should be in the given range at all times. The limitations cover the generating unit, small unit and old unit subcategories.

NOTE:**

Effluent limitations are average concentrations during a maximum of one 2-hour period a day and maximum concentrations at any time of free available or total residual chlorine. Not more than one unit at a plant may discharge free available or total residual chlorine at any time. Limitations are subject to case-by-case variances if higher levels or longer periods are needed for condenser tube cleanliness.

1. Low volume waste sources include, but are not limited to, wastewaters from scrubber air pollution control systems; ion exchange water treatment evaporator blowdown; laboratory and sampling streams; floor drainage, cooling tower basin cleaning wastes; and blowdown from recirculating house service water systems.

2. Metal cleaning wastes include any cleaning components, rinse waters, or any other waterborne residues derived from, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

3. Rainfall runoff from construction areas and material storage areas for all rainfall events less than or equal to the once in 10-year 24-hour event is to be treated.

   40CFR423 as amended March 23, 1977.

NOTE:***

BPCTCA - Best Practical Control Technology Currently Available.
BATEA - Best Available Technology Economically Achievable.
TSS - Total Suspended Solids.

The standard is based on the performance of a well designed, operated, and maintained electrostatic precipitator or baghouse control system.

3.3 SO_2 EMISSION

SO_2 emissions to the atmosphere are limited to 1.2 lb/M Btu heat input and a 90% reduction is required in potential SO_2 emissions at all times except when emissions are less than 0.6 lb/M Btu. At this level a 70% reduction is required.

Compliance with the emission limit and the percent reduction requirement is determined by using continuous monitors to obtain a 30-day rolling average. The percent reduction is computed on the basis of overall SO_2 removed by all types of technology including flue gas desulfurization systems, coal cleaning, pulverizing, or sulfur removed in bottom ash and fly ash.

3.4 NO_x EMISSION

The NO_x emission standards are based on emission levels achievable with a properly designed and operated boiler that incorporates low excess air and staged combustion techniques to reduce NO_x emissions. The levels to which emissions can be reduced also depend upon the type of fuel burned; consequently, the regulations are fuel specific standards.

Continuous compliance is required based on a 30-day rolling average. Also percent reductions in uncontrolled NO_x emission levels are required, however they are not controlling and compliance with emission limits will ensure percent reduction standards.

3.5 WASTE CONTROL

Regulations are now being developed by EPA under the authority of the Resource Conservation Recovery Act (RCRA) that treat the environmental impacts of disposal or storage of solid or liquid wastes. The sections of the proposed regulations that are of particular interest to flue gas treating are those regulating landfills and ponds.

Landfill regulations for solids wastes establish restrictions to minimize emissions during placement, reduce water content for stability of placed solids, prevent exposure of the fill to flood waters, and restrict incursion of soluble constitutents from the fill into ground or surface waters (with requirements for compliance monitoring).

Pond regulations are similar but with more stringent sealing and monitoring requirements, particularly where the pond overlays sole source aquifers.

The pond and landfill regulations direct particular attention to leaching of soluble materials present in both coal ash and SO_2 control reaction products.

3.6 PREVENTION OF SIGNIFICANT DETERIORATION

Referenced to 40CFR51, Prevention of Significant Deterioration of Air Quality, June 1978, the current standards for allowable increases over the baseline are given in Table 3-4.

The term "baseline concentration", applicable for particulate matter and SO_2 only, is used to establish the starting point for defining significant deterioration. Changes in emission levels affect the amount of air quality increment that remains available to accomodate additional growth. Baseline concentration is the ambient concentration level reflecting actual air quality as of August 7, 1977 minus any contribution on which construction commenced after January 6, 1975.

Construction permits for new facilities can be granted only when more than offsetting emission reductions are secured on a case-by-case basis prior to the facility startup.

All areas are classified as Class I, Class II, or Class III. Table 3-5 provides the area classifications.

Table 3-4

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)
Maximum Allowable Increase (Mg/m3 of air)

	Class I	Class II	Class III
Particulate Matter			
Annual Mean	5	19	37
24-Hour Maximum	10	37	75
Sulfur Dioxide			
Annual Mean	2	20	40
24-Hour Maximum	5	91	182
3-Hour Maximum	25	512	700

Notes:

1. Reference 40CFR51, Prevention of Significant Air Quality Deterioration, FRP 26380, June 19, 1978.

2. No states have PSD regulations approved by the EPA, therefore, the above maximum allowable increases apply to all states.

3. For any period other than the annual period, the applicable maximum allowable increase may be expected during one such period program at any location.

4. Class I area indicates parks and wilderness areas greater than 5000 to 6000 acres. Class II and Class III indicate all other areas.

Table 3-5

DESIGNATION OF AREAS
PREVENTION OF SIGNIFICANT DETERIORATION

CLEAN AIR ACT AMENDMENTS OF 1978

The most stringent standards are those for the types of areas designated as Class I. These areas are mostly recreational areas where air quality is an essential item contributing to the use value of the region. The divisions of Class I areas are listed below:

1. International parks.
2. National wilderness areas greater than 5000 acres.
3. National memorial parks greater than 5000 acres.
4. National parks greater than 6000 acres.

Any other area, unless otherwise specified in the state legislation creating such an area, is initially designated Class II but may be redesignated as Class III after the state consults with the elected local leadership.

Section 4

SITE SELECTION AND COAL SOURCES

4.1 SITE SELECTION

Engineering economics and environmental regulations were the two major factors determining the suitability of the sites for power plant location.

4.1.1 Engineering Economics

The criteria of the engineering economics analysis having the major influence on the selection of the power plant sites and related capital costs were:

Geological and Soil Conditions. Foundations typical of the construction in the particular region were assumed for each plant. Pile foundations were assumed in the Great Lakes and Gulf areas and spread footings were assumed to be adequate in other regions.

Seismology of the Area. The map of Figure 4-1 shows the Uniform Building Code's assessment of seismic zones in the United States. Each zone indicates the severity of earthquakes experienced in the areas marked. The construction costs of the foundations and structures were increased in the estimates to reflect the strengthening required in the various earthquake zones. Most of the plants are in minor-to-moderate earthquake areas. Only the plant in Utah is located in a zone where major earthquakes may occur.

Site Development. A land area of 800 acres is assumed to be required for plants using high sulfur coal and 400 acres for plants using low sulfur coal. Land areas were analyzed for mass earthwork requirements, construction necessary to provide road access, railroad access spur, waste disposal areas, and coal-handling construction.

Water Supply. Each site was reviewed for availability of an adequate water supply, intake structure and pumping facility requirements, and delivery system and surge pond construction.

Site Elevation. Since the elevation above sea level has a significant effect on the design of steam generators and related equipment, the analysis compensated for variations in elevation at the various sites. The plant with the greatest elevation, 4700 ft, is Plant No. 6 near Delta, Utah.

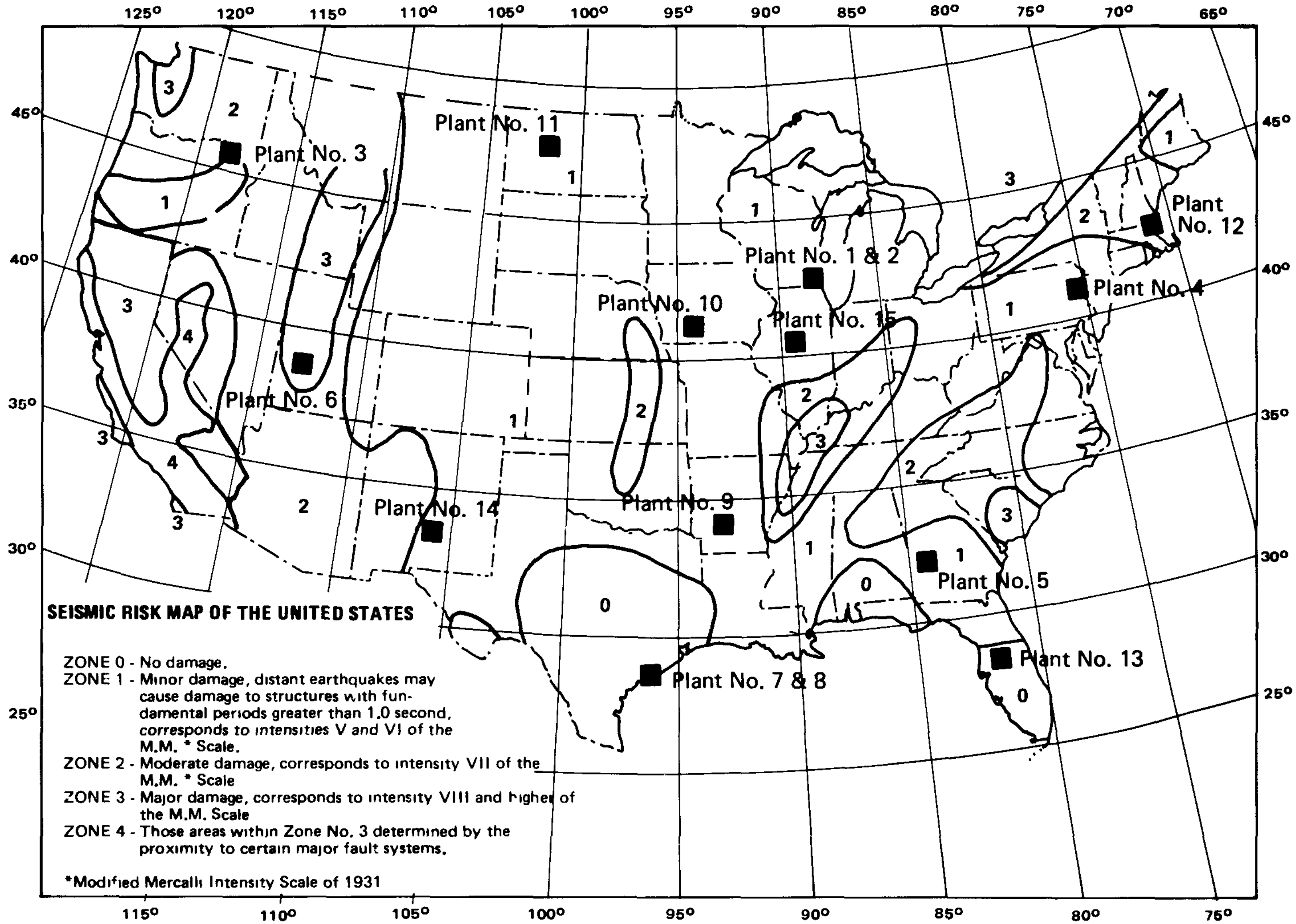


Figure 4-1. Seismic Zone Map of the United States

Labor Supply. Construction labor costs were adjusted to reflect the local labor availability, productivity, wage rates, and fringe benefits anticipated at the particular sites.

4.1.2 Environmental Regulations

Under the National Environmental Policy Act of 1969 (NEPA), federal agencies must consider the environmental effects of any "significant actions." An example of a significant action is the decision by the responsible federal agency to issue a construction or operation permit to an applicant for a private industrial project. Section 102(2) (A) of NEPA requires that federal agencies shall:

> Utilize a systematic, interdisciplinary approach which will ensure the integrated use of the natural and social sciences and the environmental design arts in planning, and in decision-making which may have an impact on man's environment.

NEPA also requires that the responsible federal agency prepare an environmental impact statement which addresses "alternatives to the proposed action."

For the purposes of the study, the environmental impact of the plants were considered to be governed by their effect on the following criteria:

- Land and water ecology.
- Air quality.
- Water quality.
- Noise control.
- Waste disposal.
- Land use.

The estimated costs for complying with the federal regulations have been included in the capital cost estimates.

4.1.3 Site Screening

The previous site selection criteria were used to review the potential sites for suitability. This preliminary comparison enables potentially unsuitable sites to be eliminated and sites subject to severe adverse effects to be avoided.

Table 4-1 shows the 15 sites studied and their relative ratings with regard to receiving construction permits.

Two of the sites studied were changed from previous locations to comply with air quality regulations. Plant No. 11 in North Dakota was changed from Bowbells to Velva and Plant No. 14 in New Mexico was changed from Farmington to Mesquite.

Table 4-2 lists the selected sites together with their respective coal sources and Figure 4-2 shows the plant and coal source locations.

4.2 COAL SOURCES

The sources of the coals selected for the plants are shown in Table 4-2. The coals are typical of the coal resources currently used for fueling power plants and anticipated to be used for the next 20 years. The Powder River coal basin, which is typical of the available reserves, contains an estimated 110 billion tons.

The characteristics of the coals that have the most significant impact on capital costs are heating value, and sulfur, ash, and moisture contents.

4.2.1 Heating Value (Btu/lb)

The heating value of the selected coals range from 5790 Btu/lb to 12,130 Btu/lb. The steam generating, coal-handling, and related facilities for each plant were adjusted for their respective heating values and referenced to the base plant which uses Illinois coal with a heating value of 10,100 Btu/lb.

4.2.2 Sulfur Content (%)

The lowest sulphur content in any of the coals is 0.24% and the highest is 6.9%. Under the NSPS regulations, all large scale power boilers burning coal require the installation of an FGD system to reduce SO_2 emissions; consequently, an FGD system has been included in all power plant estimates.

4.2.3 Ash Content (%)

A high ash content causes increased slag production in the boiler and requires additional coal-pulverizing capacity as well as expanded ash-handling and disposal facilities. In addition, a low sodium content in the ash may cause significantly increased precipitator costs. The coal mined in Alabama has the highest ash content, 27.0%, and that from North Dakota the lowest, 5.5%. The Illinois coal for the base plant has a content of 16.0% which is close to the average percentage of all the coals.

Table 4-1

SITE SCREENING

No.	Location Site	State	Ambient Air Quality Standards: Site Attainment Status	Ambient Air Quality Standards: Adjacent Areas Free Of Nonattainment Status	Prevention of Significant Deterioration: No PSD Class I Areas within 50 mi.	Prevention of Significant Deterioration: Could site comply PSD Class II?	Move Site to Achieve Air Quality Regulations: AAQS	Move Site to Achieve Air Quality Regulations: PSD	Subjective Ratings: Good	Subjective Ratings: Average	Subjective Ratings: Poor
1	Kenosha (Bit)	WI	Attainment	No-NA area to site for particulates	Yes	Possibly not (old plants nearby)	Yes-West ~25 mi	Yes-West ~25 mi		X	
2	Kenosha (Subbit)	WI	Attainment	"	Yes	"	"	"		X	
3	Hermiston	OR	Attainment	Yes	Yes	Yes	-	-	X		
4	Bethlehem	PA	Nonattainment for particulates	No-NA areas around Site for particulate, SO_2	Yes	Possibly not	Yes-West(?)	Unknown			X
5	Albany	GA	Attainment	Yes	Yes	Yes	-	-	X		
6	Delta	UT	Attainment	Yes	Yes	Yes-however-high terrain must be examined	-	West ~25 mi	X		
7	Freeport	TX	Attainment	No-NA area east for particulates	Yes	Yes	No	-		X	
8	Freeport	TX	Attainment	Same	Yes	Yes	No	-		X	
9	Fordyce	AR	Attainment	Yes	Yes	Yes	-	-	X		
10	Panora	IA	Attainment	No-NA area east for particulates	Yes	Yes	Yes-West ~25 mi	-		X	
11	Velva	ND	Attainment	Yes	Yes	Yes	-		X		

Table 4-1

SITE SCREENING

(cont'd)

No.	Location Site	State	Ambient Air Quality Standards: Site Attainment Status	Ambient Air Quality Standards: Adjacent Areas Free Of Nonattainment Status	Prevention of Significant Deterioration: No PSD Class I Areas within 50 mi.	Prevention of Significant Deterioration: Could site comply PSD Class II?	Move Site to Achieve Air Quality Regulations: AAOS	Move Site to Achieve Air Quality Regulations: PSD	Subjective Ratings: Good	Subjective Ratings: Average	Subjective Ratings: Poor
12	Quincy	MA	Nonattainment for particulates	No-NA areas around site for particulates	Yes	Possibly not	No	No			X
13	Dade	FL	Attainment	No-NA area to SW of site for particulates	Yes	Yes	Yes-North ~25 mi	-		X	
14	Mesquite	NM	Attainment	Yes	Yes	-	-	-	X		
15	Glassford	IL	Nonattainment for particulates SO_2	No	Yes	Possibly not	Yes-SW ~25 mi	-		X	

Table 4-2

SELECTED SITES AND COAL SOURCES

	Power Plant Locations			Coal Sources			
	Region	State	Nearest Town	Type	State	County	Seam
1.	East Central	Wisconsin	Kenosha	Bituminous	Illinois	St. Clair	No. 6
2.	East Central	Wisconsin	Kenosha	Subbituminous	Wyoming	Campbell	Smith) Roland)
3.	West	Oregon	Hermiston	Subbituminous	Wyoming	Campbell	Smith) Roland)
4.	Northeast	Pennsylvania	Bethlehem	Bituminous	W. Virginia	Harrison	Pittsburgh
5.	Southeast	Georgia	Albany	Bituminous	Kentucky	Hopkins	No. 9
6.	West	Utah	Delta	Bituminous	Utah	Carbon	Gilson) Rock Canyon) Sunnyside)
7.	South Central	Texas	Freeport	Subbituminous	Montana	Rosebud	Rosebud) McKay)
8.	South Central	Texas	Freeport	Lignite	Texas	Milam	Wilcox
9.	South Central	Arkansas	Fordyce	Lignite	Arkansas	Dallas	Wilcox
10.	West Central	Iowa	Panora	Bituminous	Iowa	Mahaska	Lower Ford
11.	West Central	N. Dakota	Velva	Lignite	N. Dakota	Ward	Coteau
12.	Northeast	Massachusetts	Quincy	Bituminous	W. Virginia	Logan	Cedar Grove
13.	Southeast	Florida	Dade City	Bituminous	Alabama	Walker	American) Mary Lee)
14.	West	N. Mexico	Mesquite	Bituminous	N. Mexico	San Juan	Lemon) Purple) Azure) Gold) Scarlet)
15.	East Central	Illinois	Glassford	Bituminous	Illinois	Macoupin	No. 6

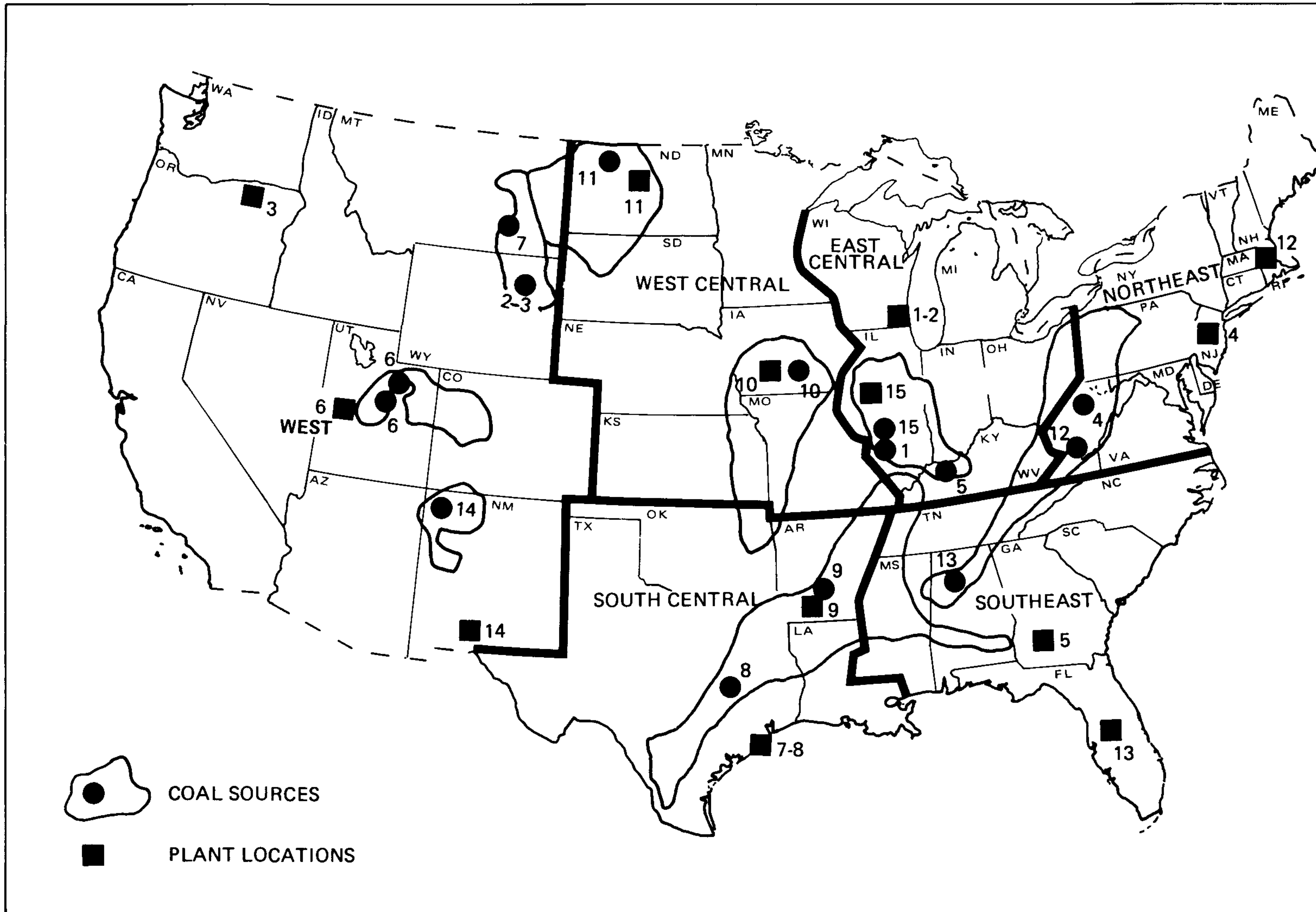


Figure 4-2. Power Plant Locations and Coal Sources

4.2.4 Moisture Content (%)

The lignite and subbituminous coals in the west have a moisture content of approximately 30% which requires higher temperature primary air to the coal pulverizers to remove the excess moisture. This is not required for the bituminous coal of as that of the Illinois coal of the base plant.

4.2.5 Selected Coal Analysis

The proximate and ultimate analysis of the selected coals are shown in Table 4-3 together with their heating value and ash-softening temperature.

Table 4-3

SELECTED COAL ANALYSES

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
STATE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
COAL TYPE	Bituminous	Subbituminous	Subbituminous	Bituminous	Bituminous	Bituminous	Subbituminous	Lignite	Lignite	Bituminous	Lignite	Bituminous	Bituminous	Bituminous	Bituminous
Proximate Analysis %															
Moisture (as received)	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
Volatile Matter	33.0	31.1	30.9	34.5	37.7	29.6	27.5	33.2	29.2	35.7	26.3	30.6	24.2	29.5	35.4
Fixed Carbon	39.0	32.1	32.8	42.5	45.9	38.0	38.0	26.8	15.0	33.5	29.5	46.8	40.3	32.0	35.5
Ash	16.0	6.4	5.9	15.0	8.2	22.9	9.0	9.0	18.1	15.1	5.5	16.0	27.0	19.5	16.5
Ultimate Analysis %															
Ash	16.00	6.40	5.78	14.97	8.17	22.90	9.04	9.0	18.12	15.12	5.51	16.04	27.03	19.50	16.50
Sulfur	4.00	0.48	0.32	3.38	3.40	0.64	0.60	0.99	0.44	6.90	0.24	0.85	1.26	0.52	3.39
Hydrogen	3.70	3.40	3.44	4.40	4.59	3.82	3.34	3.20	2.87	3.65	2.75	4.24	3.66	3.65	4.00
Carbon	57.60	47.87	47.48	63.27	66.55	53.59	50.40	39.76	31.03	50.87	39.49	66.39	52.69	46.70	53.81
Nitrogen	0.90	0.62	0.67	1.25	1.47	1.07	0.74	1.24	0.50	1.06	0.60	1.23	1.11	1.04	1.08
Oxygen	5.80	10.83	11.81	4.73	7.62	8.48	10.41	14.81	9.34	6.72	12.75	4.65	5.75	9.59	8.64
Moisture	12.00	30.40	30.50	8.00	8.20	9.50	25.47	31.00	37.70	15.68	38.66	6.60	8.50	19.00	12.58
Na_2O in Ash; %	0.6	1.3	1.1	0.5	0.2	0.8	0.3	0.3	0.2	0.2	4.0	0.3	1.7	2.7	0.5
Heating Value, Btu/lb (as received)	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
Ash Softening Temperature (Fahrenheit)	2,030	2,190	2,210	2,140	2,150	2,300	2,200	2,100	2,300	2,010	2,470	2,210	2,700	2,500	2,040

Section 5

PLANT DESCRIPTIONS

This section describes the power plants and provides the technical data for the 15 base plants and 15 alternate plants at the locations shown in Table 4-2. The data are developed from Bechtel's current experience in the design and construction of coal-fired power plants. A simplified flow diagram of the power plants is shown in Figure 5-1.

Particular emphasis has been placed on data for pollution control facilities, especially the FGD processes, because these relatively new systems are not yet as standardized in concept and design.

5.0.1 PLANT OPERATION DATA

Table 5-1 for the base cases (subcritical design) and Table 5-2 for the alternate cases (supercritical design) provide a summary of the plant performance data. The net electric power output of each plant will be 1000 MW. This figure is used as the comparison base for each of the 15 plants. Boiler efficiencies are affected by variations in the coal moisture content. The FGD equipment also increases the amount of auxiliary power required for plant service and reduces the amount of steam available for power generation.

Turbine-generators rated at 500 MW and seven extraction points as standard are available from the manufacturers. Consequently a heat cycle with seven feedwater heaters has been assumed with turbine throttle steam conditions of 2400 psig and 1000°F and reheat to 1000°F.

Review of one of the major manufacturer's heat balances for a similar unit indicates that the cycle heat rates are as follows:

Load, MW	% of Max. Guaranteed Load	Condenser Back Pressure Inches, Hg	Heat Rate Btu/kWh
514.5	100	2.0	7914
386.8	75	2.0	7939

Based on these data, it was assumed that at 90% average load and with condenser back pressure of 2.0-in. Hg, the heat rate will be about 7924 Btu/kWh. This figure was accepted for all energy conversion calculations in subcritical cases. Typical

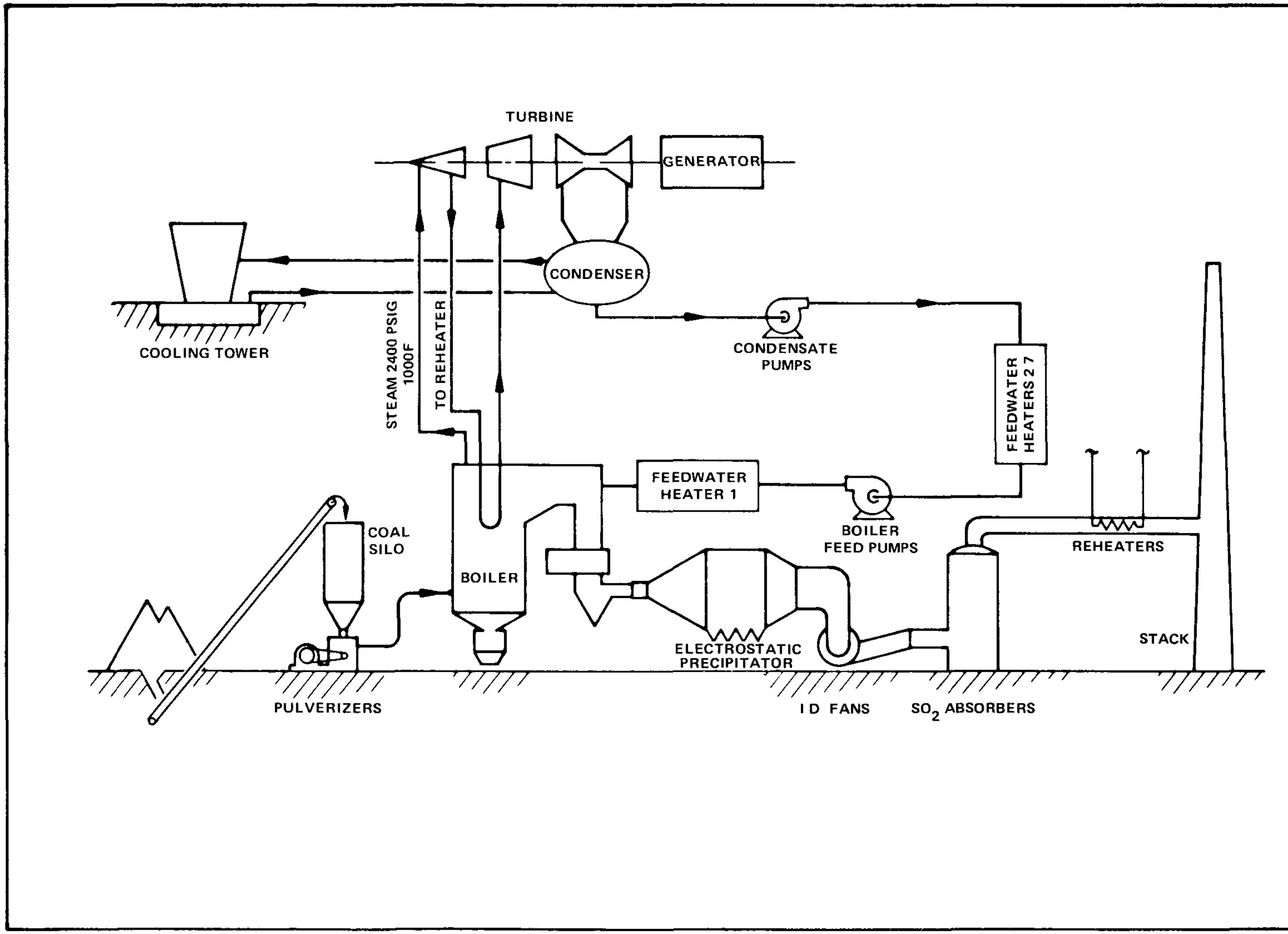


Figure 5-1. Flow Diagram of Power Plant Process

Table 5-1

PLANT OPERATION DATA - BASE PLANTS
Turbine Throttle Steam 2400 psig

PLANT NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION		Great Lakes	Great Lakes	Western	Northeastern	Southeastern	Western	South Central	South Central	South Central	West Central	West Central	Northeastern	Southeastern	Western	Great Lakes
SOURCE OF COAL		Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
COAL HEATING VALUE - Btu/lb		10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE - %		12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT, MW		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NUMBER OF UNITS		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT, EACH, MW		500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
DATA FOR EACH UNIT																
ANNUAL AVERAGE PERFORMANCE @ 70% LOAD FACTOR*																
Avg. Steam Cycle Heat Rate	Btu/kWh	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924	7,924
Avg. Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Avg. Gross Heat Rate	Btu/kWh	9,035	9,355	9,344	8,974	8,974	9,005	9,235	9,422	9,759	9,108	9,617	8,944	8,974	9,171	9,056
Avg. Penalty For Scrubber Gas Reheat	Btu/kWh	180	-	-	179	179	-	-	-	-	182	-	-	-	-	181
Avg. Adjusted Gross Heat Rate	Btu/kWh	9,215	9,555	9,344	9,153	9,153	9,005	9,235	9,422	9,759	9,290	9,617	8,944	8,974	9,171	9,237
Avg. Allowance for Auxiliaries	Btu/kWh	677	712	710	648	637	716	694	727	847	685	783	647	677	736	671
Avg. Net Heat Rate	Btu/kWh	9,892	10,067	10,054	9,801	9,790	9,721	9,929	10,149	10,606	9,975	10,400	9,591	9,651	9,907	9,908
Avg. Heat Input to Boiler x 10^6	Btu/Hr	4,451	4,530	4,524	4,410	4,406	4,374	4,468	4,567	4,773	4,489	4,680	4,316	4,343	4,458	4,459
Avg. Coal Burn Rate	Tons/Hr	220	282	278	192	182	227	261	309	412	238	351	185	230	270	226
Annual Coal Consumption x 10^3	Tons/Yr	1,502	1,925	1,892	1,305	1,237	1,545	1,777	2,103	2,809	1,618	2,391	1,259	1,566	1,841	1,540
PERFORMANCE AT FULL LOAD																
Steam Cycle Heat Rate	Btu/kWh	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/kWh	9,024	9,344	9,333	8,963	8,963	8,993	9,224	9,410	9,746	9,097	9,604	8,932	8,963	9,160	9,045
Net Heat Rate	Btu/kWh	9,853	10,029	10,017	9,764	9,750	9,682	9,891	10,109	10,558	9,937	10,359	9,553	9,614	9,869	9,871
Rated Heat Input to Boiler	10^6 Btu/Hr	4,927	5,015	5,009	4,882	4,875	4,841	4,946	5,505	5,279	4,969	5,180	4,777	4,807	4,935	4,936
Rated Coal Burn Rate	Ton/Hr	244	313	307	212	201	251	289	342	456	263	388	204	254	299	250
Turb.-Gen. Gross Output	MW	531	531	532	530	529	534	531	533	537	531	534	530	531	534	531

*Based on 80-100% Load (90% average) x 77.8% Operating Time.

Table 5-2

PLANT OPERATION DATA - ALTERNATE PLANTS
Turbine Throttle Steam 3500 psig

PLANT NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION		Great Lakes	Great Lakes	Western	Northeastern	Southeastern	Western	South Central	South Central	South Central	West Central	West Central	Northeastern	Southeastern	Western	Great Lakes
SOURCE OF COAL		Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
COAL HEATING VALUE - Btu/lb		10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE - %		12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT, MW		1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NUMBER OF UNITS		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT, EACH, MW		500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
DATA FOR EACH UNIT																
ANNUAL AVERAGE PERFORMANCE @ 70% LOAD FACTOR*																
Avg. Steam Cycle Heat Rate	Btu/kWh	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705	7,705
Avg. Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Avg. Gross Heat Rate	Btu/kWh	8,786	9,097	9,086	8,726	8,726	8,756	8,980	9,162	9,489	8,856	9351	8,696	8,726	8,918	8,806
Avg. Penalty For Scrubber Gas Reheat	Btu/kWh	175	-	-	173	173	-	-	-	-	176	-	-	-	-	175
Avg. Adjusted Gross Heat Rate	Btu/kWh	8,961	9,097	9,086	8,899	8,899	8,756	8,980	9,162	9,489	9,032	9,351	8,696	8,726	8,918	8,981
Avg. Allowance for Auxiliaries	Btu/kWh	602	635	634	574	564	639	618	650	763	610	702	573	602	657	597
Avg. Net Heat Rate	Btu/kWh	9,563	9,732	9,720	9,473	9,463	9,395	9,598	9,812	10,252	9,642	10,053	9,269	9,328	9,575	9,578
Avg. Heat Input to Boiler x 10^6	Btu/Hr	4,303	4,379	4,374	4,263	4,258	4,228	4,319	4,415	4,613	4,339	4,524	4,171	4,198	4,309	4,310
Avg. Coal Burn Rate	Tons/Hr	213	273	268	185	176	219	252	298	398	230	339	179	222	261	219
Annual Coal Consumption x 10^3	Tons/Yr	1,452	1,861	1,829	1,262	1,196	1,493	1,717	2,033	2,715	1,565	2,311	1,217	1,514	1,780	1,490
PERFORMANCE AT FULL LOAD																
Steaam Cycle Heat Rate	Btu/kWh	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661
Boiler Efficiency	%	87.7	83.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/kWh	8,735	9,045	9,034	8,676	8,676	8,706	8,929	9,109	9,435	8,806	9,297	8,647	8,676	8,867	8,755
Net Heat Rate	Btu/kWh	9,452	9,648	9,636	9,393	9,379	9,313	9,515	9,725	10,157	9,560	9,965	9,190	9,247	9,492	9,496
RAted Heat Input to Boiler	10^6 Btu/Hr	4,726	4,824	4,818	4,697	4,690	4,657	4,758	4,863	5,079	4,780	4,983	4,595	4,624	4,746	4,748
Rated Coal Burn Rate	Tons/Hr	234	301	296	204	193	241	278	329	439	253	374	197	245	288	241
Turb.-Gen. Gross Output	MW	528	528	528	527	526	530	528	529	533	528	531	527	528	530	528

*Based on 80-100% Load (90% average) x 77.8% Operating Time.

steam flow rate diagrams and tables are shown in Appendix C. It is acknowledged that under hot and humid conditions performance efficiency would change and the condenser back pressure actually would vary. However, this report did not take into consideration such a variable in the projection of capital cost.

5.0.2 PRINCIPAL PLANT SYSTEMS

Principal plant systems, except the FGD (See Tables 5-3 and 5-4), are listed in Tables 5-5 and 5-6. Coal will be received in open gondolas built for rotary dump service or, for Plant No. 5, in open top hopper bottom cars. The coal dead storage pile consists of a long-term reserve storage of 60 days. The live storage pile capacity can supply two units at full load during a two-day weekend or 64 hours between successive deliveries.

Electrostatic precipitator design gas flow per unit, total surface collection area, and specific collection areas (SCA) are given in Table 5-5. Cleaning the flue gases from boilers burning Powder River coal requires a precipitator of special design with an SCA of 750 rather than 400, and a collection area approximately 80% larger than those required for the eastern coals. Power plants are fully enclosed at all locations.

5.0.3 FLUE GAS DESULFURIZATION

5.0.3.1 Process Selection

The 1979 NSPS and the relevant state standards are summarized in Section 3.

FGD installations are required to meet the emission standards with the typically available coals. For this study, a calcium-based FGD system is selected using lime or limestone. Selection of alkali is influenced by local availability and delivered cost to the site under consideration.

Regenerable systems with sulfur recovery were not selected because they are generally in a less advanced state of technical development, are more complex, and are strongly influenced by local markets for the end product.

The spray tower type absorbers used in this study maximize system reliability through simplicity of design, and their energy requirements in pumping and fan losses tend to be lower than other configurations.

The operating parameters in Table 5-3 are compatible with the required SO_2 removal efficiency.

5.0.3.2 FGD Process Layout and Design

The FGD unit will be located between the induced draft fans and the stack. Four identical 33-1/3% capacity absorber trains will be installed in parallel for each of the two units. Each train will consist of a spray tower absorber along with recirculating and wash tray slurry systems, a treated gas reheater where applicable, and associated ductwork. Alkali storage and makeup facilities, wash tray circuit, slurry dewatering, and waste stabilization systems are common to the four absorber trains. The stabilized sludge disposal building is common to both units.

Figures 5-2 and 5-3 are typical of the process flows for both limestone and lime systems.

Absorber trains operate under positive pressure, and each train normally treats one-third of the flue gas under full load operation with the fourth train as spare. A fly ash free bypass, capable of handling the entire flue gas stream discharged from the electrostatic precipitators will be furnished to maintain uninterrupted power generation during major emergencies of the entire FGD system.

FGD systems are assumed to be operated in a closed-loop mode without need for handling liquid wastes.

Reheat of the saturated absorber exit gases by $50^{\circ}F$ will be provided in cases where high sulfur coals being burned. Steam for this indirect heating will be provided from the steam cycle. In cases of low sulfur coals where portion of the flue gas will bypass the absorbers, reheat will be provided by the bypassed flue gas.

Stabilization of waste solids will be accomplished before transporting the waste sludge to the disposal site. This will include mixing of dewatered FGD reaction products with the dry fly ash removed by the electrostatic precipitators. Since the leaching characteristics of such mixtures vary widely, lime will be used as a fixation additive for environmental acceptability of the throwaway waste product.

Table 5-3

FGD SYSTEM PARAMETERS - BASE PLANTS

PLANT NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PLANT LOCATION		Great Lakes	Great Lakes	Western	Northeast	Southeast	Western	South Central	South Central	South Central	West Central	West Central	Northeastern	Southeastern	Western	East Central
SOURCE COAL		Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
COAL SULFUR, AVG	%	4.0	0.48	0.32	3.38	3.40	0.64	0.60	0.99	0.44	6.90	0.24	0.85	1.26	0.52	3.39
MAX	%	5.2	1.00	0.51	4.73	4.22	0.90	0.90	1.49	0.66	9.66	0.36	1.28	1.76	0.73	4.75
AS SO_2 IN FLUE GAS	%	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
H.H.V.	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
RATED HEAT INPUT TO BOILER	10^6 Btu/hr	4,927	5,015	5,009	4,882	4,875	4,841	4,946	5,055	5,279	4,969	5,180	4,777	4,807	4,935	4,936
ENVIRONMENTAL REGULATIONS		EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA
LOAD FACTOR (YEARLY BASIS)	%	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
FLUE GAS AT FGD. BATTERY LIMIT (285^oF, + 10 in w.g.)	10^3 ACFM	1,806	1,928	1,883	1,725	1,692	1,973	1,809	1,727	1,994	1,813	2,026	1,684	1,686	1,981	1,760
EXCESS AIR AT BATTERY LIMIT	%	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42

DATA FOR EACH UNIT

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
FLUE GAS PER ABSORBER (SATURATED)	10^3 ACFM	509	456	408	486	476	420	399	463	461	511	441	375	438	496	497
FLUE GAS BYPASSED AROUND ABSORBERS(1)	%	NIL	24	24	NIL	NIL	24	24	15	24	NIL	24	24	15	20	NIL
TOTAL BYPASS, HOT	10^3 ACFM	-	463	452	-	-	474	434	261	479	-	486	404	256	404	-
SO_2 POSSIBLE EMISSION (AVG. S. FULL LOAD)	lb/hr	39,026	6,002	3,932	28,673	27,329	6,421	6,925	13,524	9,023	72,559	3,728	6,952	12,819	6,220	33,938
ALLOWABLE EMISSION (AVG. S. FULL LOAD)	lb/hr	3,903	1,801	1,180	2,929	2,925	1,926	2,078	3,033	2,407	5,963	1,118	2,086	2,884	1,678	3,394
REMOVAL (AVG. S. FULL LOAD)	%	90	70	70	89.8	89.3	70	70	77.6	70	91.8	70	70	77.5	73.0	90
NUMBER OF ABSORBER TRAINS INCL. SPARE		4	4	4	4	4	4	4	4	4	4(2)	4	4	4	4	4
ABSORBER TYPE		Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower	Spray Tower
SUPERFICIAL GAS VEL. (SAT'D, FULL LOAD)	FT/SEC	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
SYSTEM PRESSURE DROP	IN H_2O	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
LIQUID/GAS RATIO (AVG. S./MAX. S.), TOTAL	GAL/MCF	102/120	57/62	56/58	98/112	94/104	59/61	59/61	62/66	57/60	57/78(3)	55/56	61/64	63/68	58/60	92/112
PRESATURATION SPRAYS	GAL/MCF	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
ALKALI/SO_2 STOIC. RATIO (BASIS SO_2 ABS'D)		1.3	1.1	1.1	1.3	1.3	1.1	1.1	1.1	1.1	1.3	1.1	1.1	1.1	1.1	1.3
ABSORBER DELAY TANK RESIDENCE TIME	MIN.	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
ABSORBENT SOLIDS	%	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
DEWATERED SLUDGE SOLIDS	%	50	45	45	50	50	45	45	45	45	50	45	45	45	45	50
STACK GAS REHEAT BY STEAM	^oF	50	-	-	50	50	-	-	-	-	50	-	-	-	-	50
STACK GAS REHEAT WITH BYPASSED GAS AVG. S./MAX. S. BASIS)	^oF	-	33/22	33/34	-	-	36/36	33/30	19/6	31/25	-	32/32	35/20	20/9	27/15	-

(1) Under normal operating conditions. 100% bypass capability provided.
(2) Two absorbers in series per train.
(3) L/G figures are for both absorbers in each train.

Table 5-4

FGD SYSTEM

RAW MATERIALS AND WASTE PRODUCTION SUMMARY - BASE PLANTS

PLANT NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
PLANT LOCATION		Great Lakes	Great Lakes	Western	Northeastern	Southeastern	Western	South Central	South Central	South Central	West Central	West Central	Northeastern	Southeastern	Western	East Central
COAL SOURCE		Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
RAW MATERIALS PER UNIT																
Alkali Type		Limestone	Pebble Lime	Pebble Lime	Limestone	Limestone	Pebble Lime	Pebble Lime	Pebble Lime	Pebble Lime	Limestone	Pebble Lime	Pebble Lime	Pebble Lime	Pebble Lime	Limestone
Storage Capacity, Day Supply Quantity		60	30	30	60	60	30	30	30	30	60	30	30	30	30	60
(Avg. Load, Avg. S.)	Tons	36,100	1,100	750	26,500	25,100	1,200	1,300	2,800	1,500	68,600	700	1,300	2,700	1,250	31,400
Consumption																
(Full Load, Max. S.)	T/D	1,118	121	55	884	748	80	94	222	112	2,347	49	96	192	85	1,048
(Full Load, Avg. S.)	T/D	860	53	35	630	597	57	61	133	71	1,633	33	61	126	54	748
(Avg. Load, Avg. S.)	T/Yr	219,800	13,500	8,900	161,000	152,600	14,600	15,600	34,000	18,100	417,000	8,400	15,700	32,300	13,800	191,200
WASTE PER UNIT																
Stabilized Sludge																
(Full Load, Max. S.)	Tons/Hr	152.6	43.5	27.0	122.6	95.0	65.0	42.4	74.7	93.2	285.7	28.6	48.5	98.4	66.9	148.3
(Full Load, Max. S.)	Cu. Yd./D	4,521	1,289	800	3,633	2,815	1,926	1,256	2,213	2,762	8,465	847	1,437	2,916	1,982	4,394
(Full Load, Avg. S.)	Tons/Hr	124.7	28.2	22.3	94.8	78.6	59.8	35.0	54.9	83.0	208.6	24.9	40.6	83.8	59.9	115.5
(Avg. Load, Avg. S.)	Cu. Yd./Yr	944,300	213,500	168,700	717,900	595,200	452,800	265,000	415,700	628,500	1,579,600	188,600	307,400	634,600	453,600	874,600
Moisture Content[1]																
(Full Load, Avg. S.)	%	37	23	19	36	41	12	21	29	10	41	16	18	18	12	35

[1]Water of hydration is not included.

Table 5-5

PRINCIPAL PLANT SYSTEMS - BASE PLANT

(Excluding FGD Systems)

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL TYPE	Bituminous	Subbituminous	Subbituminous	Bituminous	Bituminous	Bituminous	Subbituminous	Lignite	Lignite	Bituminous	Lignite	Bituminous	Bituminous	Bituminous	Bituminous
COAL HANDLING SYSTEM ARRANGEMENT	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)
RAIL CAR TYPE GONDOLA	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Hopper Bottom	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump
COAL DEAD STORAGE PILE, TONS/UNIT (60-Day)	250,000	325,000	320,000	220,000	210,000	260,000	300,000	355,000	470,000	270,000	400,000	215,000	265,000	310,000	255,000
COAL LIVE STORAGE PILE, TONS/UNIT (3-Day)	15,000	20,000	20,000	13,000	13,000	15,000	18,000	22,000	28,000	16,000	25,000	13,000	16,000	18,000	15,000
Precipitators, Specific Collection Area - Sq. Ft/1000 ACFM	400	600	600	380	325	750	675	700	750	400	340	700	750	750	415
Gas Flow - ACFM	2,092,000	2,260,000	2,213,000	2,000,000	1,966,000	2,348,000	2,113,000	2,023,000	2,334,000	2,102,000	2,373,000	1,974,000	1,979,000	2,328,000	2,046,000
Total Surface - SF	837,000	1,355,000	1,328,000	760,000	639,000	1,761,000	1,426,000	1,416,000	1,750,000	841,000	807,000	1,382,000	1,484,000	1,746,000	850,000
Bottom Ash Pond Area, Acres	15	8	7	12	6	23	10	12	32	15	8	12	27	22	16
Cooling Tower Blowdown Disposal After Treatment (Assume Detaining Pond 3 Acres)	To Lake	To Lake	To Irrigation	To River	To River	To River	To Coast	To Coast	To River	To River	To River	To Coast	To Lake	To River	To River
Coal Yard Drainage	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond

Table 5-6

PRINCIPAL PLANT SYSTEMS - ALTERNATE PLANT

(Excluding FGD Systems)

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL TYPE	Bituminous	Subbituminous	Subbituminous	Bituminous	Bituminous	Bituminous	Subbituminous	Lignite	Lignite	Bituminous	Lignite	Bituminous	Bituminous	Bituminous	Bituminous
COAL HANDLING SYSTEM ARRANGEMENT	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)	(Per Dwg)
RAIL CAR TYPE GONDOLA	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Hopper Bottom	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump	Rotary Dump
COAL DEAD STORAGE PILE, TONS/UNIT (60-Day)	250,000	320,000	315,000	215,000	205,000	260,000	300,000	350,000	465,000	265,000	400,000	210,000	260,000	305,000	250,000
COAL LIVE STORAGE PILE, TONS/UNIT (3-Day)	15,000	20,000	20,000	13,000	13,000	16,000	18,000	20,000	28,000	16,000	25,000	13,000	16,000	18,000	15,000
Precipitators, Specific Collection Area - Sq. Ft/1000 ACFM	400	600	600	380	325	750	675	700	750	400	340	700	750	750	415
Gas Flow - ACFM	2,025,000	2,188,000	2,742,000	1,936,000	1,903,000	2,273,000	2,045,000	1,958,000	2,260,000	2,035,000	2,297,000	1,911,000	1,916,000	2,254,000	1,981,000
Total Surface - SF	810,000	1,313,000	1,286,000	736,000	619,000	1,705,000	1,380,000	1,371,000	1,694,000	814,000	781,000	1,338,000	1,437,000	1,690,000	823,000
Bottom Ash Pond Area, Acres	15	8	7	12	6	23	10	12	32	15	8	12	27	22	16
Cooling Tower Blowdown Disposal After Treatment (Assume Detaining Pond 3 Acres)	To Lake	To Lake	To Irrigation	To River	To River	To River	To Coast	To Coast	To River	To River	To River	To Coast	To Lake	To River	To River
Coal Yard Drainage	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond	To Pond

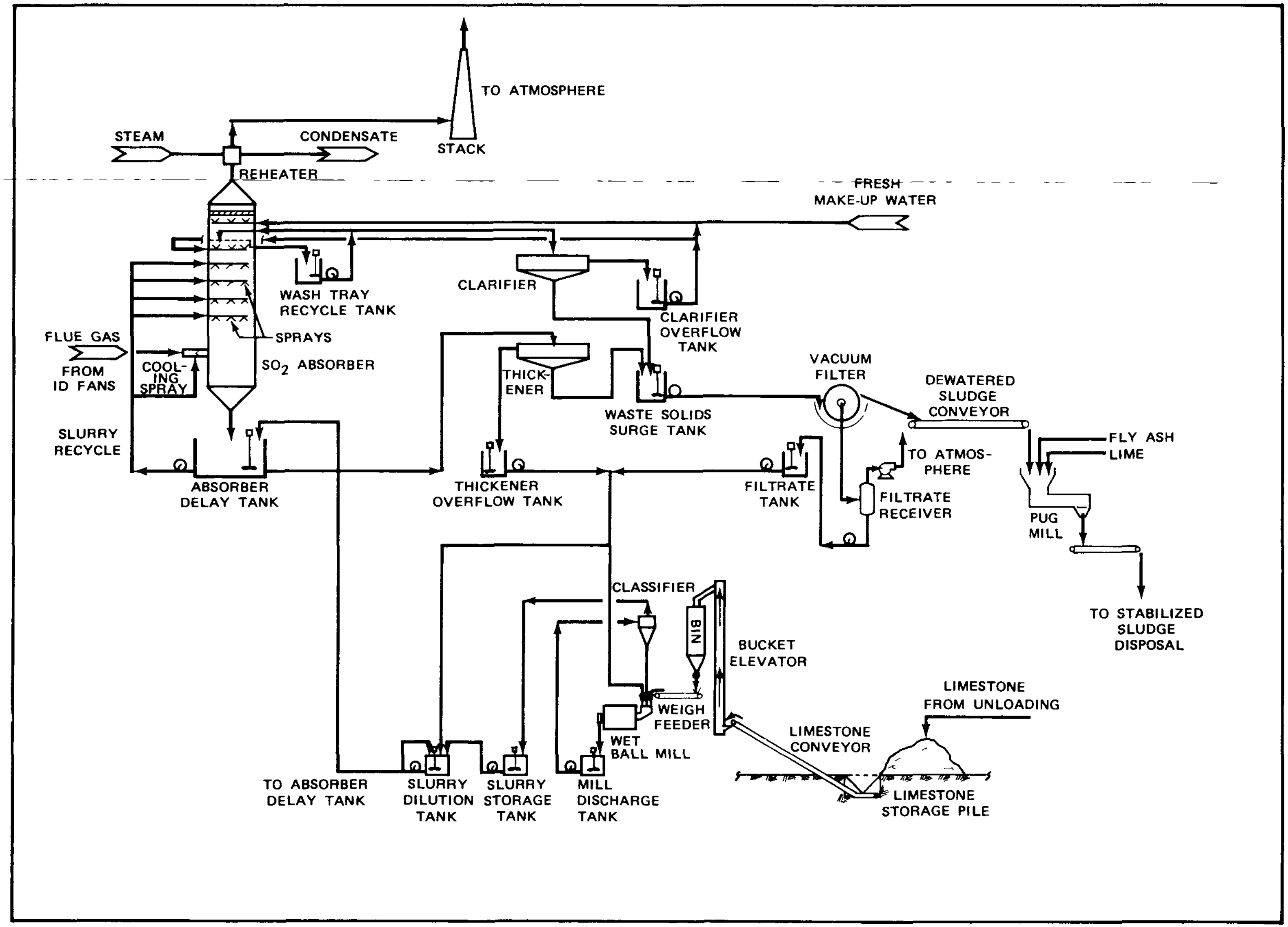


Figure 5-2. Flue Gas Desulfurization - Limestone Process Flow Diagram

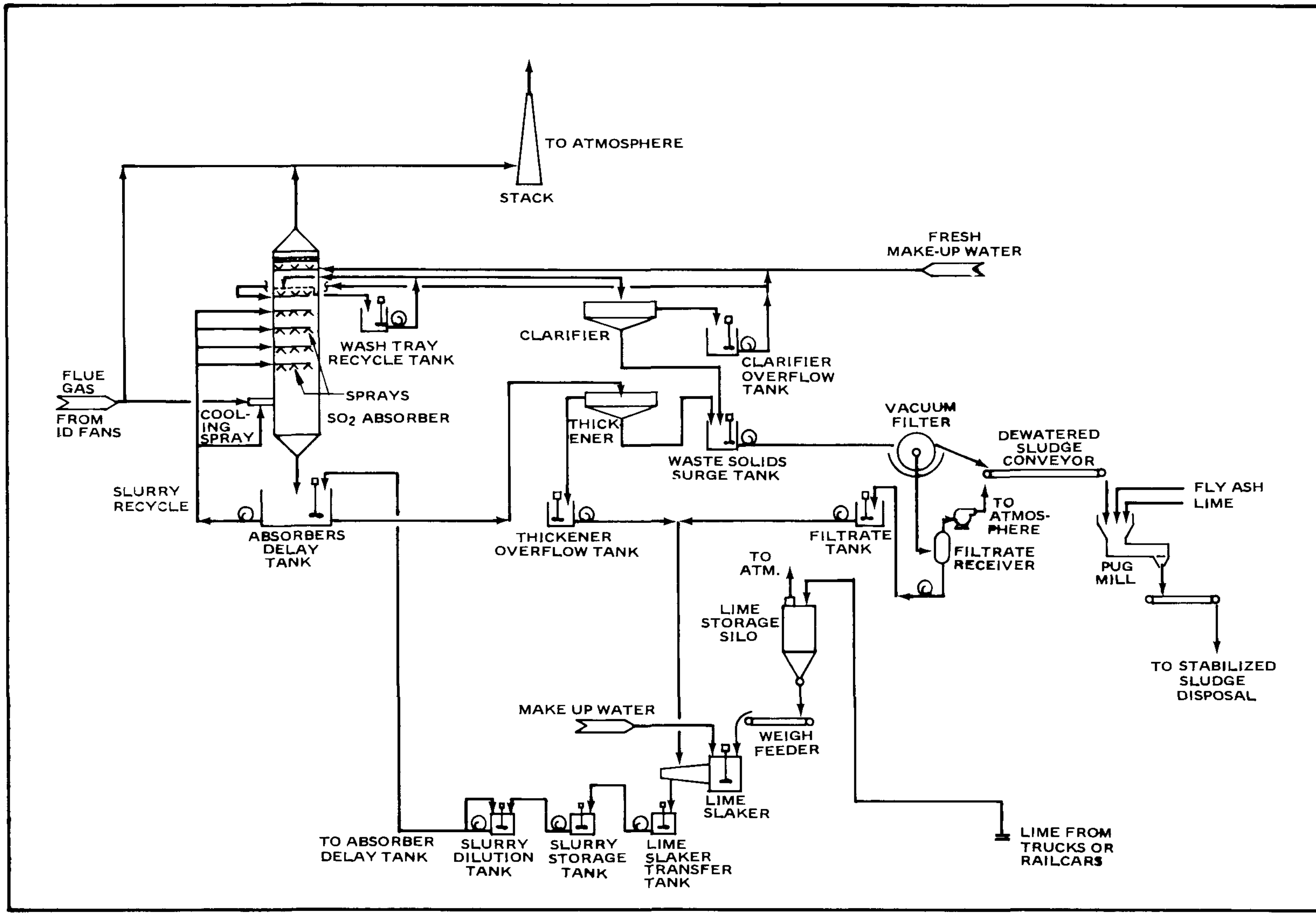


Figure 5-3. Flue Gas Desulfurization - Lime Process Flow Diagram

Table 5-3 lists the design parameters for the proposed FGD systems. Table 5-4 summarizes the raw materials and solids production.

Other criteria are discussed in Sections 5.1.5, 5.2.5, and 5.3.1.

5.0.4 Liquid Wastes and Disposal

Liquid wastes from the power plant are from the following sources:

1. Raw water clarifier/filter system waste.
2. Demineralizer regeneration waste (neutralized).
3. Cooling tower blowdown.
4. Building floor and roof drains.
5. Coal yard drainage.
6. Yard rainfall runoff (uncontaminated).
7. Sanitary wastes.
8. Switchyard drains.

It is proposed that these wastes be disposed of as follows:

Item 1 to an SO_2 sludge thickener.

Items 2, 3, and 4 to a separate pond having a clay lining. The quality of each flow will be monitored by instruments. The pond water will be treated for pH, and the decanted overflow will be allowed to reenter the river, lake, or sea. The quality of effluent will be monitored.

Item 5 to a separate pond having a clay lining. The pond water will be monitored for pH, and the decanted overflow will be allowed to runoff in the river, lake, or sea. The effluent quality will be monitored.

Item 6 to the river, lake, or sea.

Item 7 to primary and secondary treatment facilities. The effluent will be allowed to runoff into the river. The effluent will be monitored for suspended solids and bacteria.

Item 8 to an oil separator and pond, and into the river, lake, or sea after treatment.

The above methods are in line with current federal regulations. Approval of appropriate federal, state, and local authorities will be necessary prior to implementation.

5.0.5 Solid Wastes and Disposal

Solid wastes from the FGD will be combined with fly ash and lime as fixative additive. For this estimate, the material is assumed to be suitable for landfill disposal using truck-handling and placement. This presumes that groundwater contamination by leaching is held to the necessary level by the sludge treatment and placement procedures. Land requirements for sludge disposal were assumed to be approximately 600 acres in the case of limestone systems and 200 acres in the case of lime systems. Any variance due to different types of coals used at specific plant sites were not considered in the capital cost projection.

Bottom ash disposal will be to a small, three acre, bottom ash pond from which the ash may be periodically removed by dragline and trucked to an offsite disposal area.

5.0.6 Electrical Systems

Electrical system and equipment are unit system design. The generator connects through disconnect links to the main transformer with an isolated phase bus. A tap with disconnect links from the isolated phase bus will be furnished for connection to the unit auxiliary transformer.

Synchronizing, metering, relaying, and control of the generator and line OCBs, load control of the generating unit, and control of the 4160- and 480-volt station electrical systems are provided in the control room.

The unit auxiliary transformer provides an auxiliary system power at 4160 volts and is backed by the station auxiliary transformer fed from a 115-kV overhead line.

In addition, an emergency engine-driven generator provides standby 480-volt power to the vital services system.

4160-volt switchgear bus sections, fed from the unit auxiliary transformer, supply power for the station auxiliary system main auxiliary motors and the 480-volt load center transformers. The 480-volt system includes motor control centers located in equipment areas.

The switchyard services the two generating units, two startup transformers, three transmission lines, and an emergency supply line of lower voltage (115 kV). A single aluminum bus-single breaker scheme with bus sectionalizing breakers of 345 kV will be furnished. The switchyard will be equipped with circuit breakers, disconnect switches, line traps, potential devices, and lightning arresters. Also included are foundations, control building, supporting structures, and take-off towers.

5.1 PLANT NO. 1 - GREAT LAKES LOCATION - ILLINOIS COAL (BASE DESIGN)

The two unit 1000-MW plant will be considered typical of a coal-fired power plant in the Great Lakes region. It will be fueled with the high sulfur (4.0%), high Btu/lb (10,100) bituminous coal mined in Illinois. It will be designed to satisfy EPA standards. An electrostatic precipitator of standard design with an SCA of 400 and a total surface area of 670,000 sq ft will be furnished to remove the fly ash from the flue gas. A limestone slurry FGD system will complete the cleaning of the flue gas. A more detailed description of the FGD and other environmental quality control follows in Section 5.1.5.

A detailed description of the plant is provided in this section and, for the purpose of the study, will be considered as the base design. The other plants will be described by comparison to this plant.

5.1.1 General Plant Description

The plant is assumed to be located in Wisconsin, near Kenosha, approximately six miles from Lake Michigan (Figure 4-2). This site, typical of the region, is 600 ft above sea level in Seismic Zone 1. Land area required for the plant will be about 800 acres which will accommodate a future plant extension of the same power output (not including land for a sludge disposal site for a second unit).

A one-mile road and a two-mile railroad spur are assumed to be required for access to the plant.

Soil conditions are assumed to be such that friction piles approximately 100 ft long will be required for the design of all foundations.

The following codes will govern the plant design:

- ASME Boiler and Pressure Vessel Code.
- ANSI Power Piping Code.
- National Electrical Code.
- NFPA Code.
- OSHA Regulations.
- EPA Federal Standards.
- Uniform Building Code.
- Local Regulatory Agency Guidelines.

5.1.2 Plant Systems and Major Equipment

Each of the two units wil be self-contained with only minimum interconnections as may be required by the common systems listed below.

Each steam cycle will include a boiler, turbine-generator, condenser, seven regenerative feedwater heater stages (including a deaerator), and two steam-turbine boiler feed pumps. Systems furnished for each unit and designed for power plant service will include:

- Boiler system.
- Turbine-generator system.
- Condensate system.
- Feedwater system.
- Extraction steam system.
- Main steam and reheat system.
- Circulating water and cooling tower system.
- Raw water system.
- Demineralized water system.
- Chemical treatment system.

- Ash-handling system.
- Process waste water disposal system.
- Bearing cooling water system.
- Compressed air system.
- Lube oil-handling system.
- Sampling system.
- Air quality control system.

Common systems will be:

- Coal-handling system.
- Auxiliary boiler system.
- Raw water supply system.
- Fire protection system.
- Plant rain runoff system.
- Light oil supply system.
- Heating and ventilating system.
- Domestic water system.
- Plant waste disposal system.

Table 5-7 is a listing of the principal mechanical equipment and Table 5-8 shows the base plant data for each unit.

Each boiler will be of a balanced draft, direct-fired, pulverized coal design equipped with six mills, each capable of pulverizing 50 tons of coal per hour. Regenerative air heaters will be used to lower the exit gas temperature to 285°F. The boiler will deliver superheated steam at 2650 psig and 1000°F for conservatism of design and for plant reliability. The boiler reheater will also be designed for an outlet temperature of 1000°F.

Each turbine will be a tandem-compound unit with high-, intermediate-, and low-pressure sections with a total gross rating of 531 MW. Generators will be 3600 rpm hydrogen-cooled units designed for 624 MVA at 0.85 power factor.

Table 5-7

BASE PLANT MECHANICAL EQUIPMENT
DATA FOR EACH UNIT

TYPE OF PLANT	Coal-fired
RATED CAPACITY - NET/GROSS VWO (MW)	500/531

STEAM GENERATOR

Type	Balanced draft, direct fired, pulverized coal
Main steam - (10^3 lb/hr)	4,000
- (psig/^oF)	2650/1000
Reheat - (10^3 lb/hr)	3,300
- (^oF)	1,000
Efficiency - (%)	89.1

FUEL

Type	Bituminous
Heating value - (Btu/lb)	10,100
Maximum burn rate - (TPH)	244

TURBINE GENERATOR

Frame size	TC4F - 26" LSB
Maximum output - (MW)	531
Generator rating - (MVA/PF)	624/0.85
Exhaust	2.0" Hg

AUXILIARY BOILER
(Common to both units)

No./type/fuel	1/package/No. 2 oil
Design rating - (10^3 lb/hr	150
psig/^oF	150/500

FANS

Force draft - (No./driver)	2/motor
Primary air - (No./driver)	2/motor
Induced draft - (No./driver)	4/motor

COAL-HANDLING FACILITIES
(Common to both units)

Type	Rotary dump
Unloading rate - (No. belts/TPH)	1/3,000
Reclaiming rate - (No. belts/TPH)	2/600

ASH-HANDLING FACILITIES

Bottom ash unloading - TPH	20
Storage	Dewatering pond
Fly ash unloading - TPH	50
Storage	Silo

Table 5-7

BASE PLANT MECHANICAL EQUIPMENT (Cont'd)
DATA FOR EACH UNIT

CONDENSER

Shells	2
Surface - (SF)	200,000

FEEDWATER HEATERS

Number of shells	7 stages 6 closed, 1 open (incl. 4-1/2 capacity shells)

BOILER FEEDWATER PUMPS

Number/driver	2/turbine
Total HP - (both)	19,000
Flow ea - GPM/%	5,500/50

CIRCULATING WATER

Total flow - (GPM)	180,000
Cooling source	Cooling towers
Ambient temp./degree rise - (^{o}F)	60/30
No. pumps/HP	2/2,200

PRECIPITATOR

Type	Electrostatic
Efficiency - %	99.5
Flue gas flow - (10^3 ACFM @ ^{o}F)	2,250 @ 2850
SCA	400

MAIN POWER TRANSFORMERS

Number/type (ea/No. phases)	3/1 (1 - spare)
MVA/temp. rise	624/65^{o}F
Voltage - kV/kV	24/345

SWITCHYARD

Breakers - No.	6
Size - kV	345

Table 5-8

BASE PLANT DATA

DATA FOR EACH UNIT

AREAS & VOLUMES

Main Building

Operating Deck Height		45 ft.
Roof Height:	Turbine Bay	120 ft.
	Coal Bay	180 ft.
	Boiler	250 ft.
Area:	Turbine Bay	43,000 SF
	Coal Bay	7,000 SF
	Boiler	15,000 SF
	Auxiliary	15,000 SF
	TOTAL	80,000 SF
Volume:	Turbine Bay	3,000,000 CF
	Coal Bay	1,200,000 CF
	Boiler	3,800,000 CF
	Auxiliary Areas	2,000,000 CF
	TOTAL	10,000,000 CF

Water from the condenser will be cooled in mechanical draft cooling towers. The makeup water for cooling towers, boilers, and other plant needs will be obtained from Lake Michigan. A water intake structure complete with traveling screens and other auxiliaries will be furnished to obtain the water. A six-mile, 26-inch diameter pipeline will bring water to an 8-day supply, 500 acre-ft surge pond located near the plant.

5.1.3 Plant Arrangement

The plant arrangement is described below and shown in Figure 5-4. Both boilers and turbines will be enclosed with siding supported on steel frames.

Turbine-generators will be arranged with their shafts in line and perpendicular to the boiler centerlines. Condensers and low-pressure feedwater heaters will be located below the turbine and low-pressure exhausts with their axes perpendicular to the turbine shaft.

The turbine bay at the operating level will be free of auxiliary equipment and piping, thereby allowing a maximum of laydown space and presenting an unencumbered appearance.

Intermediate- and high-pressure feedwater heaters will be located at floor level in an auxiliary bay between the turbine-generator bay and coal bay. The deaerator will be placed above the feedwater heaters.

The two-unit control room will be located centrally between the units with the plant supervisor's office and a conference room located adjacent to the rear of the control room and at the same elevation. A testing laboratory incorporating the water and steam sample stations, analyzing equipment, and a coal sample room will be located in the area between units. Steam and water sample coolers will be placed to the rear of the terminal room and at the same elevation. The instrument repair shop will be adjacent to the conference room.

An electrical relay room and cable-spreading space will be furnished immediately below the control room complex.

Located on the ground floor and readily accessible by elevator or stairway from the control room will be the following equipment items: intermediate- and high-pressure boiler feedwater pumps, gland steam condenser, condensate pumps, hot

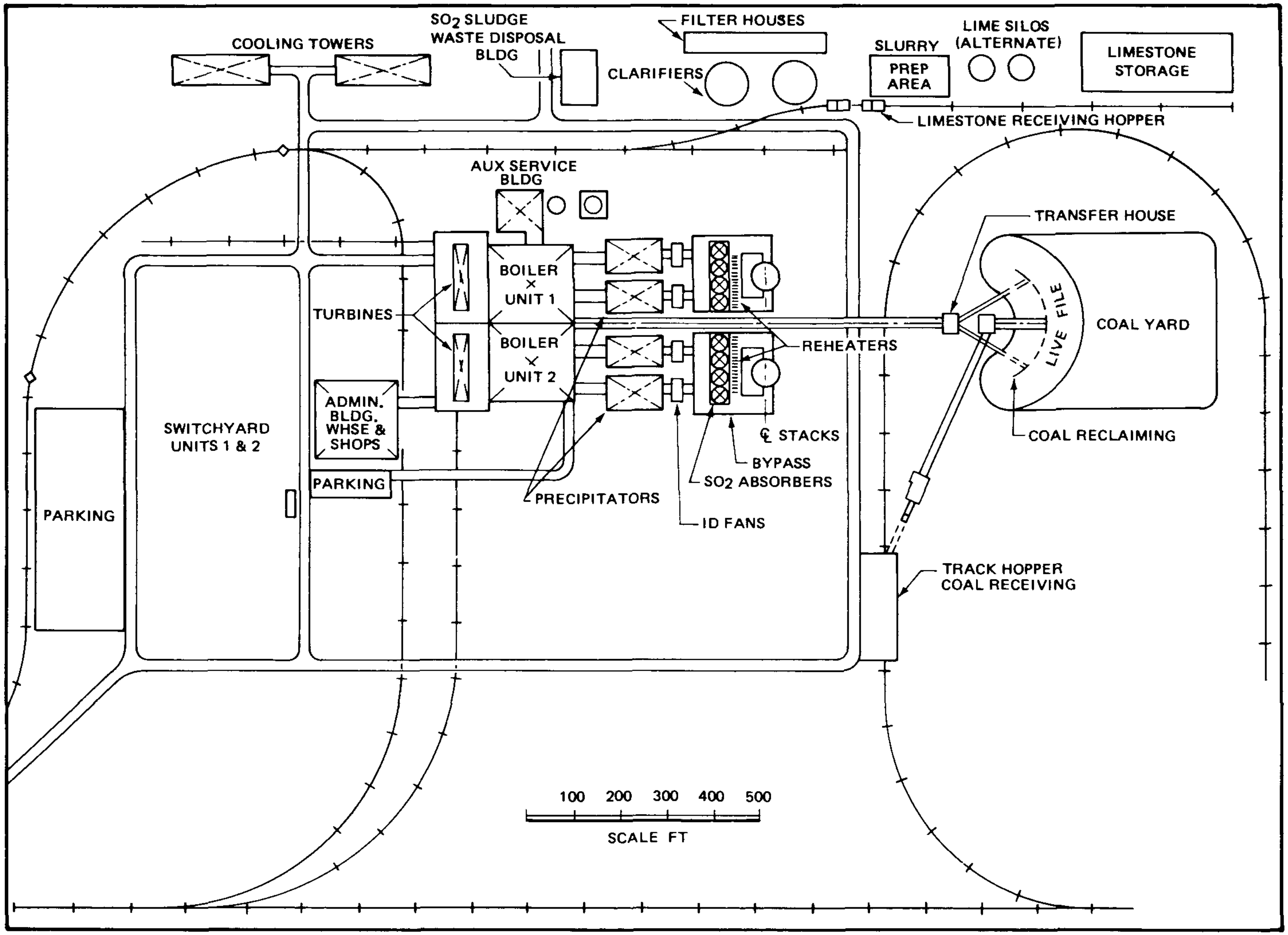


Figure 5-4. Plot Plan for Base Plant Design

water air preheater pumps, vacuum pumps, low- and high-pressure raw water pumps, coal pulverizers, demineralizers, air compressors, auxiliary cooling water heat exchangers and pumps, 6900-volt unit, and common buses.

A lubricating oil storage room, batch tanks, and associated equipment will also be furnished. A 250-volt battery room, a 125-volt battery room, and a vital services emergency generator will be located on the ground floor.

The boiler will be arranged with air preheaters inside and hot water air preheating coils outside the building. Forced draft fans and primary air fans will be outside the building. Induced draft fans will be located between the precipitators and the FGD system.

Coal will be brought into the building on reclaim conveyors that will enter along the line of symmetry between units. It will be distributed to the unit storage silos from a centrally located common surge bin by two sets of twin cascading conveyors.

The turbine bay will be 100-ft wide and will be served by two 85-ton turbine room cranes which could be coupled together to provide simultaneous lifting of heavy loads. Each crane will have a 30-ton auxiliary hook which could be dropped to the ground floor through an open hatchway above the railroad tracks and adjacent laydown area at the corner of the building. Hook lift above the operating floor will be 39 ft, adequate for maintaining the turbine-generator. Rail and truck access will be provided at one end of the turbine building.

Hoistways established on each side of the boiler for lowering boiler parts will be served by a permanently mounted five-ton hoist which could handle the heaviest anticipated load during boiler maintenance periods.

On the ground floor, major maintenance aisleways will be established along the coal pulverizer bay, at the rear of the boiler, and along the wall of the turbine bay. The maintenance aisleway will be along the line of symmetry between the units. Minimum head room in maintenance aisleways throughout the plant will be maintained 8 ft above the finished floor. Forklift access will be provided to most major pieces of equipment by aisleways 9-ft wide by 9-ft high. Heavy lifts not served by forklifts will be by monorail. In general, floor areas served by forklifts will be concrete construction. Some traffic areas will have grating or checker plate flooring. Walkways will have a 2-ft 6-in. minimum width.

A passenger elevator serving both units will be located adjoining the line of symmetry that divides the units. Landings will be established at all plant floors and major boiler platforms. A freight elevator will be furnished in Unit 2.

Acid and caustic storage tanks for demineralizer regeneration will be furnished together with acid and caustic supply pumps.

The water treatment facility will be capable of supplying the requirements of all the units.

An administration building and shop will be furnished for plant management.

5.1.4 Coal-Handling System

The coal-handling system will be as shown in Figure 5-5. Coal will be received in unit trains consisting of 100-ton uncovered gondolas and unloaded by rotary dumper at a rate of 2,960,000 tons per year. This will be the approximate rate to sustain two boiler units operating over a yearly basis at a 70% load factor with a nominal rating of 530-MW each.

The track hopper for receiving the coal will consist of six hoppers with a total usable capacity of 350 tons. The system will be capable of receiving, unloading, and stacking out coal from the unit trains at a rate of about 3000 tons per hour.

The coal storage pile will consist of a long-term reserve storage of 60-days supply (about 500,000 tons) for the two units. A surcharge at one end of the long-term storage pile will provide a live storage capacity to operate two units full load during a 2-day weekend or 64 hours between successive deliveries.

For reliability, the reclaim system from the live coal storage pile to the common surge bin in the powerhouse for Units 1 and 2 would consist of duplicate parallel systems each rated at about 250% of the full-load burn rate of each unit. At this rating, the coal-handling system of each unit will be designed to handle coal at a rate of about 600 tons per hour or 1200 tons per hour for both units.

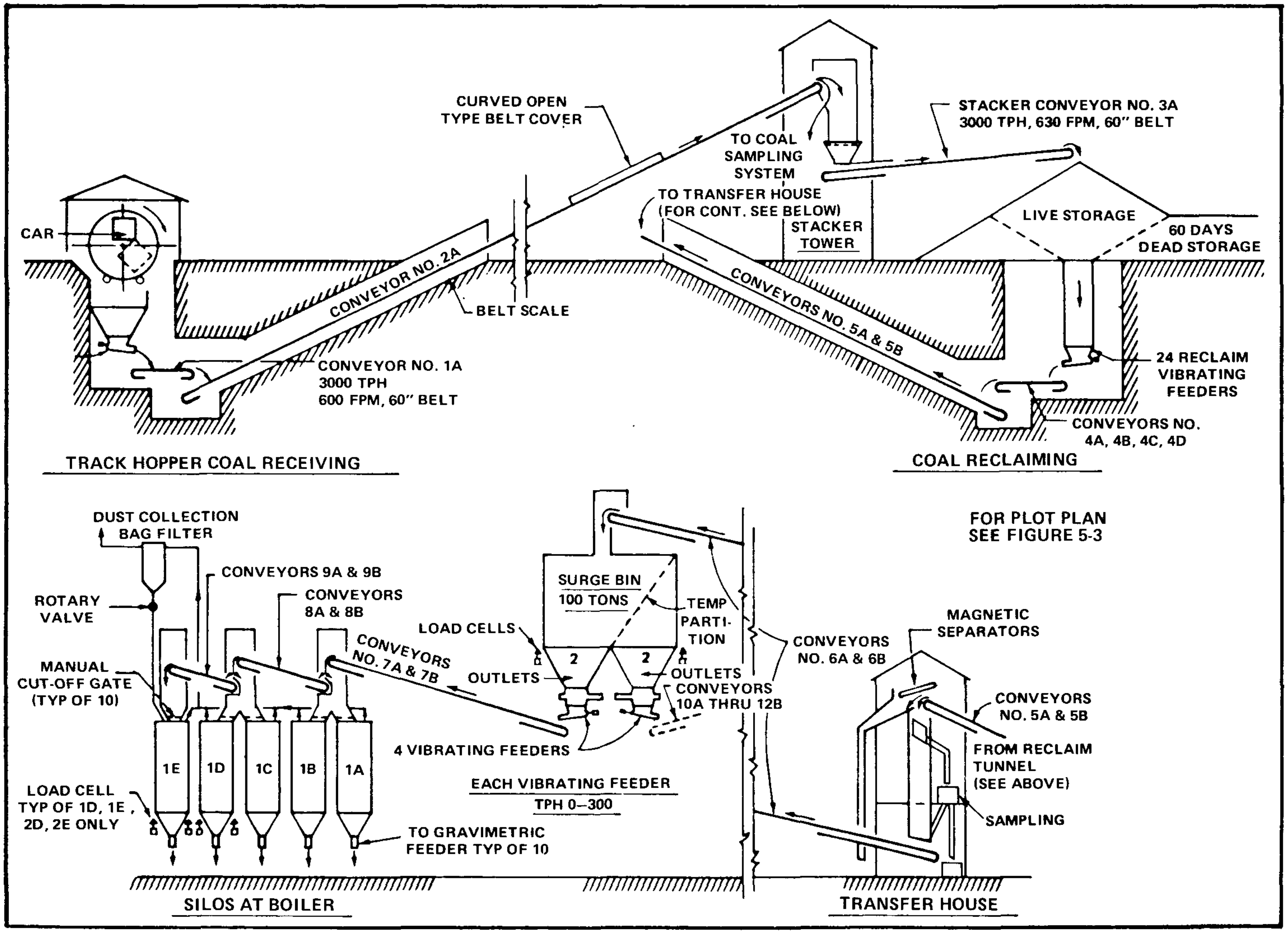


Figure 5-5. Coal-Handling System

Coal from the live storage pile will be drawn down through openings discharging to four collecting conveyors in a reclaim tunnel. Each would be 30-in. wide and travel at a speed of 500 ft/min with a capacity or 600 tons per hour.

Coal will be transferred to two parallel conveyors, 30-in. wide, which will convey the coal to a 100-ton capacity surge bin in the powerhouse.

The surge bin in the powerhouse will have four outlets at the bottom; two for each unit. Assuming that Unit 1 will be put into operation one year before Unit 2, a temporary partition wall will be furnished to eliminate a dead pocket formation in the surge bin until coal is delivered to Unit 2. Coal will be fed from the surge bin from the two outlets to two vibratory feeders. These vibratory feeders will feed onto conveyors and will form two parallel cascade systems to fill the five silos in the front of each boiler unit.

5.1.5 Flue Gas Desulfurization

Process Description. The absorption of SO_2 from flue gases by a limestone slurry involves the reactions of SO_2 with limestone ($CaCO_3$) to form calcium sulfite ($CaCO_3$) with some oxidation of the sulfite to form calcium sulfate ($CaSO_4$). The overall reactions can be represented as follows:

$$SO_2 + CaCO_3 + 1/2\ H_2O \rightarrow CaSO_3 \cdot 1/2\ H_2O + CO_2 \tag{5-1}$$

$$SO_2 + 1/2\ O_2 + CaCO_3 + 2\ H_2O \rightarrow CaSO_4 \cdot 2\ H_2O + CO_2 \tag{5-2}$$

The SO_2 is absorbed during a short residence time contact with absorbent slurry. A reaction vessel or hold tank provides the necessary residence time for dissolution of the alkaline absorbent and for precipitation of the calcium sulfite and sulfate crystals. The hold tank effluent is recycled to the scrubber to absorb additional SO_2. A slipstream from the hold tank is sent to a thickener to remove the precipitated solids from the system. The sludge stream produced by the thickener is dewatered prior to disposal. A simplified flow diagram of the limestone slurry process incorporating sludge stabilization by blending with fly ash and lime is shown in Figure 5-2.

A summary of the basic process design parameters for the limestone slurry FGD system is presented in Table 5-3. The corresponding raw material requirements and waste production rates are presented in Table 5-4.

Description of Major Process Subsystems

Slurry Preparation. Limestone is received by rail in uncovered bottom dump rail cars. Limestone storage consists of an uncovered reserve storage pile and a short-term storage bin. Limestone is ground in wet ball mills and diluted with recycled process waste water to produce slurry for makeup to the absorption section. Limestone requirements are listed in Table 5-4.

SO_2 Absorption. Flue gas from the boiler and electrostatic precipitators at 285°F and -16-in. w.g. static pressure is discharged by two induced draft fans at +10-in. w.g. pressure into a plenum from which it is distributed among the operating absorber trains. Gas entering the absorber trains is cooled and saturated by slurry sprays located in specially designed duct sections (presaturators) just upstream of the absorber inlets.

Flue gas enters the vertical, rubber-lined, carbon steel absorbers near the bottom and rises at a superficial velocity of 8.5 ft/s countercurrent to the absorbent slurry which is sprayed downward through banks of nozzles.

The FGD system would comply with the specified emission standards at 4.0% average and 5.2% maximum coal sulfur levels with 5% credit for SO_2 capture by fly ash and bottom ash. The corresponding liquid-to-gas ratios are 102 and 120 gallons per 1000 cf (saturated) respectively. Overall SO_2 removal rate is 90% as specified in the 1979 NSPS. In case of extended coal sulfur excursion above the design maximum level of 5.2%, a 30% increase in SO_2 removal capacity can be realized by commissioning the spare absorber module and operating all four of the installed absorption trains.

Entrained slurry droplets are removed from the flue gas by a wash tray system and chevron mist eliminators. Solids captured in the wash trays are separated from the tray water stream in a clarifier common to all absorber trains. The clarifier underflow stream is added to the waste sludge stream and the clarified water is returned to the wash trays. Makeup water is added through the mist eliminator wash sprays. The flue gas leaving the absorbers is reheated 50°F in convection heaters using 150 psig steam from the power plant boiler before entering the chimney.

Slurry Handling and Concentration. Absorbent slurry from each absorber will be discharged into a reaction vessel where crystallization of some of the calcium salts takes place. Rubber-lined constant-speed pumps recirculate the slurry to the absorber and presaturator spray nozzles. Limestone slurry makeup will be added to the reaction vessels to maintain a stoichiometric ratio of 1.3 based on sulfur removed. Concentration of absorbent slurry solids will be maintained at 15% wt by variation of the spent absorbent withdrawal rate.

The slurry discharged from the individual absorber trains will be combined in a single thickener for solids concentration. Clarified liquor overflows from the thickener and will be returned to the reaction vessels. Thickener underflow will be pumped from a surge tank to a rotary vacuum filter system. Filtrate will be returned to the limestone slurry preparation area. The filter cake containing 45-50% wt solids will be discharged by conveyor to the waste sludge stabilization system. The design parameters of the FGD system are summarized in Table 5-3.

Waste Sludge Stabilization System. All plant fly ash will be conveyed to and mixed in a pug mill with the dewatered sludge from the vacuum filters. Dry lime will be added for stabilization at the rate of 2% wt of the combined weight of dewatered sludge and dry fly ash producing a mixture of at least 70% weight solids. Two parallel full capacity pug mills and stabilized sludge conveyors will be furnished. Waste product production is shown in Table 5-4.

5.2 PLANT NO. 2 - GREAT LAKES LOCATION - WYOMING COAL

This two-unit 1000-MW power plant will be at the same location as Plant No. 1, near Kenosha, Wisconsin, and will be subject to the same environmental standards. However, this plant would be fired with coal from the Powder River Basin of Wyoming rather than with Illinois coal.

Since coals from that Basin have a lower Btu value and a lower sulfur content than the Illinois coal, this change has major impact on the design of the steam generators, coal- and ash-handling facilities, the precipitators, and FGD systems. (See Table 4-3 for detailed coal analysis of two Powder River coals.)

5.2.1 General Plant Description

Plant layout and design and site facilities will be the same as those for Plant 1 described in the previous section other than changes caused by use of the Wyoming coal. Turbine-generators will be the same and have identical ratings for each turbine-generator 530 MW, 624 MVA for each unit as in Plant No. 1. Condensers and auxiliary systems will also be the same. Land area required for the plant will be about 400 acres. General site data are described in Table 5-9.

Table 5-9

SITE DATA

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
REGION	Great Lakes	Great Lakes	Western	Northeastern	Southeastern	Western	South Central	South Central	South Central	West Central	West Central	Northeastern	Southeastern	Western	East Central
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
NEAREST TOWN	Kenosha	Kenosha	Hermiston	Bethlehem	Albany	Delta	Freeport	Freeport	Fordyce	Panora	Velva	Quincy	Dade City	Mesquite	Glassford
COAL TYPE	Bituminous	Subbituminous	Subbituminous	Bituminous	Bituminous	Bituminous	Subbituminous	Lignite	Lignite	Bituminous	Lignite	Bituminous	Bituminous	Bituminous	Bituminous
COAL SOURCE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
Road - miles	1	1	15	2	5	1	2	2	2	2	2	2	3	2	2
Railway - miles	2	2	8	4	5	3	5	5	40	15	3	3	2	2	5
Distance from major water - miles	6	6	20	2	5	2	2	2	11	11	3	2	2	2	3
Elevation above sea level - feet	600	600	700	300	200	4,700	100	100	800	1,000	1,400	100	100	3,000	700
Seismic Zone	1	1	2	1	1	3	0	0	1	1	1	3	0	1	1
Environmental Regulations	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA
Foundation Type	Piles	Piles	Spread Footings	Spread Footings	Spread Footings	Spread Footings	Piles	Piles	Piles	Piles	Spread Footings	Spread Footings	Piles	Piles	Piles
Intake Structure and Pumping Plant	Yes (Lake Michigan)	Yes (Lake Michigan)	Yes (Columbia R.)	Yes (Delaware R.)	Yes (Reservoir)	Yes (Sevien R.)	Yes (Coast)	Yes (Coast)	Yes (Saline R.)	Yes (Racoon R.)	Yes (Souris R.)	Yes (Coast)	Yes (Lake)	Yes (Rio Grande)	Yes (Illinois R.)
Raw Water Supply Pipeline - miles (Surge Pond 500 acre ft; Surge Pond Pumping Plant)	6	6	13	5	4	2	2	2	11	11	3	2	1	2	3
Raw Water Treatment Plant	None	None	None	2 clarifiers & gravity filters	None	None	None	None	None	None	None	None	None	None	None
Cooling Tower Type	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft	Mechanical Draft

5.2.2 Steam Generators

Steam generators will remain the balanced draft direct-fired pulverized coal design delivering superheated steam at 2650 psig and 1000°F. Exit gas temperature is 285°F. However, the steam generators will be designed for the Wyoming coal. Btu value is approximately 30% lower, ash content 65% lower, and sulfur content 90% lower. Moisture content is 250% higher.

Changes in design requirements include additional air preheating surface to provide hot air for drying the coal in the pulverizers, necessary because of the high moisture content (30%).

Powder River coal also has more unfavorable slagging characteristics and, therefore, the furnaces will be larger and additional soot-blowers will be installed.

5.2.3 Coal-Handling Systems

Coal-handling systems for receiving, storing, reclaiming, and distributing the Wyoming coal will be similar to the systems for the Illinois coal. However, the facilities will be designed for handling the 30% higher tonnage of required coal. Storage piles will also be proportionately larger.

5.2.4 Precipitators

Where the precipitators for Plant No. 1 are standard design with an SCA of 400 and a total collection surface of 900,000 sq ft, precipitators for this plant will be quite a different design in order to clean the flue gas produced from burning western coal. The SCA will be 750 and the total collection surface 1,775,000 sq ft, about 100% more. In addition, the precipitator will not be standard design but rather a special design for the more extreme duty.

5.2.5 Flue Gas Desulfurization

Plant No. 2 burns coal with a sulfur content of 0.48%. The FGD system required by Plant No. 2 will differ from Plant No. 1 in that the alkali for the absorption of SO_2 will be quicklime instead of limestone.

Process Description. The lime slurry process is very similar to the limestone slurry process (Section 5.1.5) in process chemistry, equipment design, and operating problems. The descriptions provided in this section make reference to those provided in Section 5.1.5 and serve to highlight the differences between the lime and limestone processes.

The overall reactions occuring in the lime slurry process are:

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3 \cdot 1/2\ H_2O \qquad (5\text{-}3)$$

$$SO_2 + 1/2\ O_2 + CaO + 2\ H_2O \rightarrow CaSO_4 \cdot 2\ H_2O \qquad (5\text{-}4)$$

A simplified flow diagram of the lime slurry process is shown in Figure 5-2.

A summary of the basic process design parameters for the lime slurry FDG system is presented in Table 5-3. The corresponding raw material and waste production are presented in Table 5-4.

Description of Major Process Subsystems

Slurry Preparation. Pebble lime will be delivered by either covered truck or rail car and pneumatically unloaded into storage silos. Lime is slaked with makeup water, diluted with recycled process water, and stored for use as absorbent makeup. All material-handling rates and storage volumes will be smaller than the corresponding values for the limestone slurry system because of the lower coal sulfur concentration and lower lime molecular weight, higher reactivity, and reduced stoichiometric ratio associated with the lime slurry process (1.1 versus 1.3 for limestone).

SO_2 Absorption. The SO_2 absorption section for the lime slurry system will be similar to the limestone slurry system with three major exceptions:

(1) The spray tower-type absorbers will be sized for the lower flue gas volume as the NSPS June 1979 requirements for overall SO_2 removal rate is 70% in case of low sulfur western coals allowing 24% of the flue gas to be bypassed.

(2) The absorbent recycle slurry pumping system will be sized for the lower liquid-to-gas ratio (L/G) permitted by the more reactive lime absorbent. The liquid-to-gas ratios are 57 and 62 gallons per 1000 cf (saturated) of flue gas for average and maximum sulfur conditions respectively.

(3) Flue gas reheat will be accomplished by mixing the cooler scrubbed gas with the hot bypassed gas. In case of average sulfur, the gas leaves the absorber at a temperature of 133°F and will be reheated to about 168°F to enter the stack.

Slurry Handling and Concentration and Waste Product Stabilization. These sections are similar to, but smaller than, the corresponding sections of the limestone slurry system. The absorbent slurry makeup system is sized to handle the smaller makeup rate associated with the lower molecular weight of lime and stoichiometric ratios, the sludge dewatering equipment is sized for lower sludge production, and the sludge blending and storage equipment is sized for the lower sludge solids production rate.

Development Status. The status of the development of the lime system is similar to that of the limestone slurry FGD process due to their chemical and mechanical similarities. (See Section 5.1.5.) The decision to use either the lime or limestone process depends on local economic factors related to the delivered cost of alkali, sludge disposal costs, and relative capital costs.

5.3 PLANT NO. 3 - WESTERN LOCATION - WYOMING COAL

This two-unit 1000-MW power plant will be considered typical of a coal-fired power plant in the western region of the United States. It will be the same as Plant No. 2 described in the previous section except for its location.

Plant 3 will be fueled with the low Btu (8150/lb), low sulfur (0.32%), high moisture (30%), and low ash (6%) subbituminous coal mined in the Powder River region of Wyoming and Montana. Coal would be rail delivered by unit train in open gondola cars built for rotary dump service, the same as Plant No. 2.

5.3.1 Environmental Requirements

Some coal mines in the Powder River Basin can produce and selectively ship coals with low sulfur contents. However, as with Plant No. 2, a lime slurry FGD system has been assumed necessary to conform to the new EPA NSPS.

System parameters and raw material and solids production for the lime slurry process are given in Tables 5-3 and 5-4.

5.3.2 General Site Description

A plant location has been selected near Hermiston, Oregon where both makeup water and rail access are readily available. At this location, the Columbia River will be the source of raw water supply for plant makeup use.

Site data assumed for this location are given in Table 5-9 to reflect typical requirements in the west. A river intake and pumping plant will supply raw water from the Columbia River to a 500 acre-ft surge pond through a 13-mile, 26-in. diameter pipeline.

The plant site will be 700 ft above sea level in Seismic Zone 2. Foundation conditions are such that the plant can be supported on spread footings, without piles, on rock strata close to the surface.

5.3.3 General Plant Description

Plant arrangement and plant equipment types will be similar to those described for Plant No. 2, other than changes resulting from the use of the Powder River region coal.

5.3.4 Liquid Waste Disposal

Disposal of liquid wastes at this site will be the same as described for Plant No. 2 except that the monitored overflow from the pond will be diluted and used for irrigation rather than allowed to runoff into the river.

Sources of waste will be the demineralized regeneration waste (neutralized), cooling tower blowdown, building floor and roof drains, coal yard drainage, uncontaminated yard rainfall runoff, and sanitary waste effluent after primary and secondary treatment.

This disposal method meets the current federal regulations. However, approval of appropriate federal, state, and local authorities will be necessary prior to implementation.

5.4 PLANT NO. 4 - NORTHEAST LOCATION - WEST VIRGINIA COAL

This two-unit 1000-MW power plant will be considered typical of a coal-fired power plant in the northeast region of the United States. It will be fueled with the high sulfur (3.4%), high Btu (13,280) bituminous coal mined in West Virginia and rail-delivered by unit train to the plant. It will be designed to satisfy the new EPA standards. For purposes of this study, the plant will be located near Bethlehem, Pennsylvania.

5.4.1 General Site Description

The plant site is 300 ft above sea level in Seismic Zone 1. The Delaware River will be the source of raw water supply for plant makeup. A river intake structure and pumping plant will supply the raw water to a 500 acre-ft surge pond through a five-mile, 26-in. diameter pipeline.

A two-mile road and four-mile railroad spur are assumed to be required for access to the plant. Foundation conditions are assumed to be good bearing soil or rock and the plant will be supported on spread footings without piles.

5.4.2 General Plant Description

Plant arrangement and plant equipment types will be identical to those described for Plant No. 1 except for changes resulting from the differences in the coal.

The West Virginia coal has 30% higher Btu value than the Illinois coal with 50% less ash, 67% less moisture, and 15% less sulfur (complete analysis of both coals is given in Table 4-3). Such differences affect the design, but not the type, of steam generators, electrostatic precipitators, FGD facilities, coal- and ash-handling facilities. Similar equipment to that in Plant 1 will be furnished designed for this specific coal. See Table 5-5 for comparison data.

5.5 PLANT NO. 5 - SOUTHEAST LOCATION - KENTUCKY COAL

This plant will be considered typical of a coal-fired power plant in the southeast region of the United States. Like the other plants in this study, it will be a two-unit 1000-MW power plant and, at its assumed location near Albany, Georgia, will be fueled with coal mined in Kentucky and rail-delivered by unit train. It will be designed to satisfy all EPA emission standards.

5.5.1 General Site Description

The plant site is 200 ft above sea level in Seismic Zone 1.

The Flint River nearby will be the source of raw water supply for plant makeup. An intake structure and pumping plant on the existing reservoir northeast of Albany will supply the means to pump the raw water to a 500 acre-ft surge pond near the plant through a four-mile, 26-in. diameter pipeline.

A five-mile access road and railroad spur of the same length are assumed to be required for plant access.

Good bearing soil or rock is expected at the site and spread footings will be the type of foundation used to support the plant.

5.5.2 General Plant Description

This plant's arrangement and equipment will be the same or similar to those described for Plant No. 1. The only differences are those brought about by the type of coal being burned. Kentucky coal has 20% higher Btu value than the Illinois coal with only 50% of the ash, 15% less sulfur, and two-thirds the moisture. See Table 4-3 for complete analysis of both coals.

Plant equipment such as the steam generators, electrostatic precipitators, FGD facilities, coal-handling and ash-handling systems will be designed specifically for this coal. The type of equipment and performance conditions will be the same as those for Plant No. 1. See Table 5-5 for comparison data.

5.5.3 Coal-Receiving Facility

The coal will be received in open bottom dump cars rather than gondola cars built for rotary dump service. A less expensive track hopper without rotary dump equipment will be required.

5.6 PLANT NO. 6 - WEST LOCATION - UTAH COAL

The plant will be considered typical of a two-unit 1000-MW coal-fired power plant in the western region of the United States located in the state of Utah. It will be fueled with coal mined in Carbon County, Utah which will be rail-delivered by unit train to the plant. The coal has a Btu value of 9650/lb, a sulfur content of 0.64%, and a moisture content of 9.6%.

5.6.1 General Site Description

The plant will be located near Delta, Utah at an elevation of 4700 ft and in Seismic Zone 3. The raw water supply will be from the River Sevien and will require a 2-mile, 26-in. diameter makeup pipeline together with a river intake structure and pumping plant.

Foundation conditions are assumed to be competent soil or rock and the plant will be supported on spread footings.

The plant will require a one-mile access road and a three-mile railroad access spur.

5.6.2 General Plant Description

The arrangement and equipment of the plant will essentially be the same as Plant No. 1 with two significant exceptions.

The altitude of the plant will require that the size of the steam generators and fans be significantly increased over those in Plant No. 1 and that the precipitator be approximately 225% larger than that for Plant No. 1 due to the 99.85% collection efficiency and the higher ash content of the coal.

5.6.3 Flue Gas Desulfurization

The lime system for absorption of SO_2 will be used in the FGD system and will be similar to that described for Plant No. 2.

5.7 PLANT NO. 7 - SOUTH CENTRAL LOCATION - MONTANA COAL

Plant No. 7 is considered representative of a two-unit 1000-MW coal-fired power plant in the south central region of the United States. The fuel will be a subbituminous coal mined in Rosebud County, Montana and delivered by unit rail car to the rotary dump system at the plant. The coal has a Btu value of 8570/lb, a sulfur content of 0.60%, and an ash content of 9%.

5.7.1 General Site Description

The location of the plant will be on the Texas Gulf Coast approximately 40 miles south of Galveston, Texas at an elevation of 100 ft and in Seismic Zone 0.

An intake structure and pumping plant on the coast will provide raw water through a two-mile, 26-in. diameter pipeline to a 500 acre-ft surge pond near the plant.

Soil conditions at the site are assumed to necessitate the use of 100-ft friction piles for all foundations.

Access to the site will be provided by a two-mile access road and a five-mile railroad access spur.

5.7.2 General Plant Description

Plant arrangement and equipment types will be identical to Plant No. 1 except for the changes required by the differences in the coal.

The Montana coal has a 15% lower Btu value than Illinois coal with 43% less ash, 112% more moisture, and 85% less sulphur. These variations will influence the design but not the type of equipment that will be used. The sulfur content is much lower than the Illinois coal and the FGD installation would use the lime slurry process instead of the limestone slurry process of Plant No. 1.

5.8 PLANT NO. 8 - SOUTH CENTRAL LOCATION - TEXAS COAL

Plant No. 8 will be the same as Plant No. 7 except that it will be designed to burn lignite coal mined in Milam County, Texas. It will be at the same location on the Gulf Coast and subject to the same environmental standards.

The lignite coal has a low Btu value of 7400/lb, a sulfur content of 0.99%, an ash content of 9.0%, and a high moisture content of 31.0%.

5.8.1 General Plant Description

The different characteristics of the lignite coal will require several plant design changes from the Plant No. 7 design.

The low heating value of the lignite coal will require that the capacity of the coal-handling system be increased by approximately 20% to accommodate the increased consumption. The capacity of the steam generators will also need to be increased and, even though the ash content of the lignite coal is slightly less than that of the Montana coal, the increased consumption would require an increase in the ash-handling capacity by approximately 20%.

The sulfur content of the lignite is 65% higher than the Montana coal which, combined with the increased coal consumption, causes sulfur production to be approximately twice that of Plant No. 7. The capacity of the lime slurry FGD installation will reflect the increased sulfur production and removal requirements.

5.9 PLANT NO. 9 - SOUTH CENTRAL LOCATION - ARKANSAS COAL

This plant will be typical of a two-unit 1000-MW coal-fired power plant in the south central United States. It will be fueled by lignite coal mined in Dallas County, Arkansas which will be transported in unit rail cars to a rotary dump system at the plant.

The coal has a very low heating value of 5790 Btu/lb, a sulfur content of 0.44%, an ash content of 18.1%, and a high moisture content of 37.7%.

5.9.1 General Site Description

The plant will be located near Fordyce, Arkansas approximately 70 miles south of Little Rock at an elevation of 800 ft and in Seismic Zone 1.

The raw water supply will be from the Saline River where an intake structure and pumping plant will be constructed. The water will be delivered to a 500 acre-ft surge pond through an eleven-mile, 26-in. diameter pipeline.

Soil conditions are assumed to be adequate to support the plant on spread footing foundations with some minor caisson construction.

A two-mile road and a forty-mile railroad spur will be required to provide access to the site.

5.9.2 General Plant Description

Plant arrangement and types of equipment will be the same as described for Plant No. 1 but the use of lignite coal will cause significant changes in equipment size.

The Arkansas lignite has a 43% lower Btu value than the Illinois coal with 6% less ash, 214% more moisture, and 89% less sulfur.

The low heating value will require that the volume of lignite be almost twice that of the Plant No. 1 coal. This will require that the coal-handling system and the steam generators be designed to operate with this increased fuel volume. In addition, the high moisture content will necessitate increased capacity in the air heating equipment and the ash content will require a large ash pond.

The FGD installation will use a lime absorption system to remove SO_2.

The ash-handling system will be essentially the same as that for Plant No. 1 as the increased fuel consumption is offset by the comparatively low ash content of the lignite.

5.10 PLANT NO. 10 - WEST CENTRAL LOCATION - IOWA COAL

This plant will be representative of a two-unit 1000-MW coal-fired power plant in the west central region of the United States. The fuel supply will be bituminous coal mined in Mahaska County, Iowa and will be transported by rail to the rotary dump system at the plant by unit rail cars.

The coal has a Btu value of 9450/lb, a sulfur content of 6.9%, an ash content of 15.2%, and a moisture content of 15.7%.

5.10.1 General Site Description

The location of the plant will be near Panora, Iowa approximately 40 miles west of Des Moines at an elevation of 1000 ft and in Seismic Zone 1.

The plant will require a two-mile access road and a 15-mile railroad access spur.

The allowable bearing pressure for the foundations is assumed to be insufficient to support the plant on spread footings, therefore, 100 ft friction piles will be used for all foundations.

The raw water supply will be obtained from the Raccoon River where an intake structure and pumping plant will be located. The water will be pumped 11 miles through a 26-in. pipeline to a 500 acre-ft surge pond at the plant.

5.10.2 General Plant Description

The Iowa coal and the Illinois coal have almost the same characteristics which will require both the plant arrangement and the plant equipment in the two plants to be very similar.

The Iowa coal has a 6% lower Btu value with 6% less ash, 31% more moisture, and 72% more sulfur.

The only significant difference between the two plants is the amount of SO_2 extracted by the FGD installation. Both plants will use limestone slurry to remove the SO_2 emissions but the installation for Plant No. 10 will remove approximately twice as much SO_2 as Plant No. 1. To comply with the SO_2 emission regulations, each absorber train will consist of two identical absorbers in series. Each of the two absorbers will be equipped with mechanical mist eliminators, separate reaction tanks, and slurry recycle systems. Presaturation of the hot flue gas streams will be performed before the first absorbers. A wash tray system will be furnished for the second absorbers only. Limestone slurry makeup will be added to each of the two reaction vessels in each train for stoichiometric ratio control. The balance of Plant No. 10 FGD system will be similar to Plant No. 1.

5.11 PLANT NO. 11 - WEST CENTRAL LOCATION - NORTH DAKOTA COAL

Plant No. 11 will be located in the same region as Plant No. 10 but will burn lignite coal instead of bituminous coal. The lignite will be mined in Ward County, North Dakota and transported by unit rail cars to the rotary dump system at the plant.

The lignite has a Btu value of 6670/lb, a sulfur content of 0.24%, an ash content of 5.5%, and a moisture content of 38.7%.

5.11.1 General Site Description

The plant will be located near Velva, North Dakota approximately 15 miles southeast of Minot in Seismic Zone 1 and at an elevation of 1400 ft.

Access to the site will require the construction of a two-mile road and a three-mile railroad spur.

Soil conditions are assumed to be suitable for supporting the plant on spread footings.

The makeup water supply will be obtained from the Souris River where an intake structure and pumping plant will be constructed to deliver water through a three-mile, 26-in. diameter pipeline.

5.11.2 General Plant Description

The characteristics of the North Dakota coal are typical of lignite and will require several sizing changes from the plant equipment designed for Plant No. 1.

The lignite has a 34% lower Btu value than the Illinois coal, with 94% less sulfur, 66% less ash, and 222% more moisture.

The lower heat value of the lignite will require that the coal-handling system be increased by approximately 60% over the size used for Plant No. 1 to accommodate the increased fuel consumption.

The capacity of the steam generators will also be increased to handle the larger coal throughput and the air heating equipment will be increased to compensate for the high moisture content of the lignite. Lime slurry will be used to remove the SO_2 emissions in the FGD system.

5.12 PLANT NO. 12 - NORTHWEST LOCATION - WEST VIRGINIA COAL

This two-unit 1000-MW plant is considered representative of a coal-fired power plant located in the northeast region of the United States, designed to meet the 1979 promulgated EPA standards.

It will be fueled with bituminous coal mined in Logan County, West Virginia and delivered to the plant rotary dump system by means of unit rail cars.

The West Virginia coal has a Btu value of 11,680/lb, a sulfur content of 0.85%, an ash content of 16%, and a moisture content of 6.6%.

5.12.1 General Site Description

The location of the plant will be approximately five miles east of Quincy, Massachusetts at an elevation of 100 ft and in Seismic Zone 3.

A three-mile road and a two-mile railroad spur are assumed to be required for access to the plant.

Soil conditions are assumed to be adequate to support the plant on spread footings.

The source of the raw water supply for plant makeup will be city water through a two-mile, 26-in. diameter pipeline.

5.12.2 General Plant Description

Plant arrangement and plant equipment types will be the same as described for Plant No. 1 except for changes resulting from the differences in the coal.

West Virginia coal has a 16% higher Btu value than the Illinois coal with 45% less moisture, 79% less sulfur, and the same ash content. These characteristics make the West Virginia coal a more efficient fuel and this will be reflected in the design of the plant.

Less fuel will be needed to operate the steam generators and this will also enable a smaller coal-handling system to be used and a less expensive FGD installation. Lime slurry will be used in the FGD system to remove SO_2 emissions.

5.13 PLANT NO. 13 - SOUTHEAST LOCATION - ALABAMA COAL

Plant No. 13 is representative of a two-unit 1000-MW coal-fired power plant in the southeast region of the United States. The fuel will be bituminous coal mined in Walker County, Alabama and delivered by rail to the rotary dump system at the plant.

The coal has a Btu value of 9450/lb, a sulfur content of 1.26%, a moisture content of 8.5%, and a high ash content of 27%.

5.13.1 General Site Description

The plant will be situated approximately three miles outside Dade City, Florida at an elevation of 100 ft and in Seismic Zone 0.

A three-mile road and a two-mile railroad spur will provide access to the plant.

The area around Dade City is generally swampland and it is assumed that soil conditions are such that the plant will require 100 ft friction piles for all foundations.

The raw water supply will be obtained from a local lake where an intake structure and pumping plant will be constructed. A one-mile, 26-in. diameter pipeline will deliver water to a 250 acre-ft surge pond at the plant.

5.13.2 General Plant Description

The characteristics of the Alabama coal are quite similar to the Illinois coal used for Plant No. 1. It has a 6% lower Btu value, with 68% less sulfur, 29% less moisture, and 69% more ash.

The coal-handling system will be approximately the same as that for Plant No. 1 due to the similar heat values but the design of the steam generators will be considerably modified because of the high ash content of the Alabama coal.

Lime will be used for the absorption SO_2 emission control. The FGD system will be similar to that for Plant No. 2.

5.14 PLANT NO. 14 - WEST LOCATION - NEW MEXICO COAL

This plant will be typical of a two-unit 1000-MW coal-fired power plant in the western region of the United States and is designed to meet current EPA standards.

It will be fueled with bituminous coal mined in San Juan County, New Mexico and transported by unit rail cars to the plant where it will be rotary dumped and stockpiled.

The New Mexico coal has a Btu value of 8250/lb, a sulfur content of 0.52%, an ash content of 19.5%, and a moisture content of 19%.

5.14.1 General Site Description

The proposed site of the plant will be near Mesquite, New Mexico approximately 30 miles northwest of El Paso, 3000 ft above sea level, and in Seismic Zone 1.

A two-mile rail spur will be constructed to connect the plant to the main railroad line and a two-mile access road will also be provided.

Soil conditions at the site are assumed to be such that the plant's foundations will be partly on spread footings and partly on piles.

The source of the raw water supply will be the nearby Rio Grande River where an intake structure and pumping plant will be constructed. The water will be pumped through a two-mile, 26-in. diameter pipeline to a 500 acre-ft surge pond at the site.

5.14.2 General Plant Description

The most significant differences between the New Mexico coal and the Illinois coal of Plant No. 1 are the heating value and the sulfur content. The Btu value is 18% lower with 22% more ash, 58% more moisture, and 87% less sulfur.

This heating value combined with the comparatively high elevation of the plant site will cause an appreciable increase in the size of the steam-generating installation. The coal-handling and the ash-handling systems will also be slightly larger. The low sulfur content will cause a significant decrease in the FGD installation.

Plant No. 14 will have a lime slurry FGD system process.

5.15 PLANT NO. 15 - EAST CENTRAL LOCATION - ILLINOIS COAL

Plant No. 15 will have many similarities to Plant No. 1. It will be located in the Great Lakes region and will use an Illinois coal similar to that used for Plant No. 1. It will also have the same two-unit 1000-MW plant.

The fuel will be a bituminous coal mined in Macoupin County, Illinois which will be delivered to the plant rotary dump system in uncovered gondola rail cars. It has a heating value of 9860 Btu/lb, a sulfur content of 3.39%, an ash content of 16.5%, and a moisture content of 12.58%.

5.15.1 General Site Description

The plant will be located at Glassford, Illinois approximately 20 miles southwest of Peoria, 700 ft above sea level.

As with Plant No. 1, it is assumed that the soil conditions are such that friction piles approximately 100 ft long will be required for all foundations.

Access will be provided by a two-mile road and a five-mile railroad spur.

The Illinois River will provide the raw water supply which will require the construction of an intake structure, a pumping plant, a three-mile, 26-in. diameter pipeline, and a surge pond with 500 acre-ft capacity.

5.15.2 General Plant Description

This Illinois coal has a Btu value that is 2% less than that of Plant No. 1, with 15% less sulfur, 3% more ash, and 5% more moisture. The characteristics of the two coals are so similar that no significant design differences in the plant will be required.

5.16 PLANT ALTERNATIVE DESIGN

The plants described in subsections 5.1 through 5.15 will be designed for high efficiency in base load operation without excessive efficiency loss in cycling operation. They will employ steam conditions of 2400 psi and 1000°F at turbine inlet with a single reheat to 1000°F.

Alternate designs and capital cost estimates have been prepared for plants having a maximum efficiency at 80-100% of design capacity and turbine steam pressure of 3500 psig. The increased turbine pressure will allow the plants to reduce fuel consumption by approximately 3%. This will enable the coal- and ash-handling systems to be reduced and a smaller precipitator to be utilized. The costs of the steam generators will be slightly higher, and there will be some increase in pipe wall thicknesses and sizing due to the higher pressure. The circulating water system will be of reduced capacity and lower cost to reflect the lower heat rejection requirements of the more efficient supercritical system. The FGD cost will also be reduced due to the lower gas production caused by the smaller fuel consumption.

Section 6

CAPITAL COST ESTIMATES

Capital cost estimates have been prepared for 15 subcritical and 15 supercritical power plant designs. Each plant's estimate reflects the required scope and the labor costs at each plant's specific location.

Project schedules for engineering, licensing, and construction of the plants are assumed to have the same durations even though the schedules for the actual plants might be different.

The basis and qualifications of the estimates are summarized below:

6.1 ESTIMATE BASIS

The estimates have been uniformly prepared to provide consistent economic comparisons and are based on cost information available from Bechtel's current projects and knowledge of present-day coal-fired power plant costs.

6.2 GENERAL SCOPE DEFINITION

The general scope definition of each estimate is for a complete plant located on the assumed site. The general scope is for a typical plant and switchyard without any special site requirements other than the scope and design features described in other sections of the report. Cost-sensitive baseline plant data are summarized in the tables in Section 5.

Each plant is designed to comply with all current federal, state, and local requirements known and defined as of June 11, 1979 to meet the current 1979 NSPS for particulate and SO_2 emissions.

6.3 OTHER OWNER'S COSTS

In addition to the process plant investment, there are other costs required to complete the project. These other Owner's costs have been estimated according to the economic criteria established by EPRI (Appendix A) and consist of the following items:

6.3.1 Preproduction Costs

These are the expenditures incurred for the initial training of plant operators, preoperational testing and major modifications to plant equipment, inefficient use of materials such as coal at startup, and miscellaneous administrative and support labor.

6.3.2 Inventory Capital

The capitalized inventory costs of coal and consumable supplies are included. The criteria establish these costs as being equivalent to one month's supply of coal and consumables at full plant operation.

6.3.3 Initial Catalyst and Chemicals Charge

The costs of the initial catalyst charge or chemicals contained within the process equipment.

6.3.4 Allowance for Funds During Construction

The allowance for funds during construction (AFDC) is defined as "The net cost of borrowed funds used for construction purposes and a reasonable rate on other funds when so used." AFDC rates are the weighted average cost of money used for construction generated from internal sources as well as externally generated cash. An allowance of 16.6% has been added to the estimates representing two years at 8% compounded. The two years is the time from the center of gravity of expenditures to commercial operation of the units. The 8% is the weighted average cost of money used for project financing.

6.3.5 Land

The cost of the land required for the construction of the power plant and its related facilities is included at $5000 per acre.

6.4 EXCLUDED OWNER'S COSTS

The following Owner's costs are excluded from the estimates:

6.4.1 Owner's Engineering and Home Office Costs

Owner's management, engineering, finance and accounting, procurement, and other Home Office Services directly associated with the project.

6.4.2 Transmission and Distribution

Facilities beyond the switchyard for delivery of electricity from the new plant to consumers.

6.5 SCHEDULE AND RESOURCES

All estimates are based on a standard project schedule for two-unit construction of 58 months from start of engineering to commercial operation for the first unit and 70 months to commercial operation for the second unit. Construction is scheduled on a standard work week with casual overtime included but without scheduled overtime.

The estimates and schedules assume availability of materials and permanent plant equipment on present day lead times and availability of manual and nonmanual personnel in numbers and skills as required for the engineering and construction.

6.6 LABOR AND LABOR-RELATED COSTS

All estimates reflect the costs of labor, labor-related factors, and wage rates expected at the 13 plant locations.

No incentives to attract and hold labor with the skills and in the numbers needed are assumed to be required except for Plant No. 3 located at Hermiston, Oregon and Plant No. 6 located near Delta, Utah. These sites are remote from population centers and incentives are assumed to be required to attract and hold the craftsmen. These incentives, which include travel allowances, a construction camp for single workers, trailer courts and other living accommodations, recreational facilities, food subsidies, free transportation, and the like, are assumed to add 15% to the labor cost at these sites.

6.7 PRICE LEVEL

The estimates in Tables 6-1, 6-2, 6-3, and 6-4 are at July 1, 1978 price levels and include equipment, materials, freight, labor, engineering, and other home office services. Escalation of costs beyond this date is excluded. The above price level reflects a commercial operation date of July 1, 1980 for all cases.

6.8 DISTRIBUTION OF COSTS BETWEEN UNITS

The distribution shown below is based on two assumptions. The first assumption is that, regardless of their ultimate use and benefit to both units, certain necessary facilities and services are provided for the first unit so that it can be built and operated without consideration of the second unit.

Examples include site grading and drainage, fencing, roads, railroads, temporary construction facilities, administration buildings, and warehouses. Other examples include station crane, startup steam generators, auxiliary and startup transformers, air compressors, coal receiving and storage and, for the FGDs, the stabilized sludge disposal building.

The second assumption is that the second unit, although engineered and constructed with the first unit, is completed one year later and its center of gravity of expenditures is one year later than for the first unit. Therefore, the costs of the second unit are subject to an additional year of 6% escalation.

		2x500 MW		2x1000 MW	
UNITS		1st	2nd	1st	2nd
For 7-1-78 price level estimates in Tables 6-1, 6-2, 6-3, and 6-4	%	54	46	52	48
For escalated price level estimates in Tables 6-5 and 6-6		52.5	47.5	50	50

6.9 ESCALATION

Estimates in Tables 6-1, 6-2, 6-3, and 6-4 are at the July 1, 1978 price level for all costs including materials and equipment, freight and manual labor, non-manual labor, engineering, and other home office services.

Escalation (defined as a change in cost of labor and materials resulting from wage changes for field and shop labor, changes in other production costs, or changes in market demand conditions which are reflected in the price of a finished product or service) of costs beyond this date has been added. Future escalation is, at best, a judgment number which can change rapidly due to many factors.

In Tables 6-5 and 6-6 the estimates have been escalated at the rate of 6% per year based on EPRI Technical Assessment Guide and compounded annually to the center of gravities of expenditures in order to provide estimates for plant completions and commercial operations in 1985, 1990, and 1995.

Table 6-1

BASE PLANTS-TURBINE THROTTLE STEAM 2400 PSIG
ORDER-OF-MAGNITUDE ESTIMATE SUMMARIES
$ MILLION

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE NEAR	Kenosha	Kenosha	Hermiston	Bethlehem	Albany	Delta	Freeport	Freeport	Fordyce	Panora	Velva	Quincy	Dade	Mesquite	Glassford
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL SOURCE - STATE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
EMISSION STANDARDS	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	N.Mexico	EPA
PLANT MW NET - 2 EQUAL SIZE UNITS	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500
ITEM															
10 Concrete	$19.1	$19.8	$26.5	$23.0	$16.6	$22.9	$19.8	$20.0	$20.0	$19.8	$20.2	$23.0	$16.6	$19.8	$19.1
20 Civil/Structural/Architectural															
21,22,24 Structural & Misc. Iron & Steel	17.4	17.9	28.1	19.9	13.9	21.1	17.9	18.2	18.2	17.9	18.4	19.8	13.9	17.9	17.4
25 Architectural & Finish	8.7	9.0	14.1	9.8	7.0	10.5	9.0	9.2	9.2	9.0	9.3	9.8	7.0	9.0	8.7
26 Earthwork	17.4	17.9	28.1	19.8	13.9	21.1	17.9	18.3	18.3	17.9	18.4	19.8	13.9	17.9	17.4
27 Piles and Caissons	8.8	9.2	-	-	-	-	9.2	9.3	9.3	9.2	9.4	-	8.8	9.2	8.8
28 Site Improvements	11.1	11.6	17.9	12.7	9.1	17.2	16.9	17.2	35.0	28.7	14.6	14.2	14.8	14.3	15.6
30 Steam Generators	107.0	114.4	123.6	107.2	106.3	121.4	107.8	121.0	129.3	109.1	134.5	107.2	109.1	115.9	107.9
41 Turbine Generators	55.2	55.2	57.4	56.9	54.0	57.4	55.2	56.1	56.0	55.2	56.3	56.9	54.0	55.2	55.2
42 Main Condenser & Auxiliaries	4.5	4.7	5.0	4.7	4.5	4.7	4.7	4.9	4.9	4.7	5.0	4.7	4.5	4.7	4.5
43 Rotating Equipment, Ex. T/G	14.2	14.5	15.2	14.6	13.6	14.9	14.5	17.0	17.0	14.5	17.2	14.6	13.6	14.5	14.2
44 Heaters & Exchangers	4.1	4.2	4.4	4.3	3.9	4.3	4.1	4.5	4.5	4.1	4.7	4.3	3.9	4.2	4.0
45 Tanks, Drums & Vessels	1.7	1.7	1.8	1.7	1.5	1.7	1.7	1.9	1.9	1.7	1.9	1.7	1.5	1.7	1.7
46 Water Treatment/Chemical Feed	2.8	2.7	2.8	3.4	2.6	3.0	2.7	2.8	2.8	2.7	2.9	3.4	2.6	2.7	2.8
47.0 Coal/Ash/FGD Equipment															
47.1 Coal Unloading Equipment	4.0	4.2	4.7	4.0	2.5	4.4	4.2	8.7	9.3	4.2	9.4	4.0	2.5	4.2	4.0
47.2 Coal Reclaiming Equipment	3.4	3.7	4.1	3.3	1.9	3.7	3.7	-	-	3.7	-	3.4	1.9	3.7	3.4
47.3 Ash Handling Equipment	5.1	4.9	4.9	5.0	4.8	5.8	4.9	5.5	6.7	5.1	4.9	5.0	5.6	5.3	5.1
47.4 Electrostatic Precipitators	29.0	50.1	52.3	27.7	23.7	76.4	52.8	57.7	64.7	29.1	33.5	51.1	54.6	63.0	28.9
47.6 FGD Removal Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47.8 Stack (Incl. Lining, Lights, Etc.)	5.1	5.1	6.2	5.9	4.5	6.2	5.1	5.1	5.2	5.1	5.2	5.9	4.5	5.1	5.1
48 Other Mechanical Equipment Incl. Insulation & Lagging	9.1	9.7	11.5	10.0	7.8	10.6	9.7	8.0	8.9	9.7	9.0	10.0	7.8	9.7	8.5
49 Heating, Ventilating, and Air Conditioning	2.7	2.8	3.0	2.8	2.4	2.9	2.8	2.9	2.9	2.8	2.9	2.8	2.4	2.8	2.7
50 Piping	45.8	47.2	53.0	48.7	42.0	51.4	47.1	43.8	43.6	47.2	43.8	48.7	42.0	47.2	45.8
60 Control & Instrumentation	11.4	11.9	13.2	12.3	10.5	12.8	11.8	11.4	11.3	11.8	11.4	12.3	10.5	11.8	11.4
70 Electrical Equipment (Switchgear/Transformers/MCCs/ Fixtures)	11.4	11.7	13.4	12.7	10.4	13.1	11.6	11.6	11.6	11.6	11.8	12.7	10.4	11.6	11.4

Table 6-1

BASE PLANTS-TURBINE THROTTLE STEAM 2400 PSIG
ORDER-OF-MAGNITUDE ESTIMATE SUMMARIES (Cont'd)
$ MILLIONS

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE NEAR	Kenosha	Kenosha	Hermiston	Bethlehem	Albany	Delta	Freeport	Freeport	Fordyce	Panora	Velva	Quincy	Dade	Mesquite	Glassford
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL SOURCE - STATE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
EMISSION STANDARDS	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	N.Mexico	EPA
PLANT MW NET - 2 EQUAL SIZE UNITS	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500
ITEM															
80 Electrical Bulk Materials															
81,82,83 Cable Tray & Conduit	12.2	12.0	14.0	13.2	11.0	14.0	12.2	10.4	10.4	12.2	10.5	13.2	11.0	12.2	12.2
84,85,86 Wire & Cable	13.6	14.1	15.9	15.0	12.4	15.6	13.9	11.1	11.1	13.9	11.2	15.0	12.4	13.9	13.6
- Switchyard	11.4	11.4	13.4	12.9	10.3	13.4	11.4	13.2	13.2	11.4	13.8	12.9	10.3	11.4	11.4
Subtotal	436.2	471.6	534.5	451.5	391.1	530.5	472.6	489.8	525.3	462.3	480.2	476.4	447.5	488.9	440.8
Field Distributables	44.6	45.8	58.4	63.9	49.7	54.6	44.0	41.9	49.2	44.4	47.0	57.1	40.5	45.1	44.4
Field Cost	480.8	517.4	592.9	515.4	440.8	585.1	516.6	531.7	574.5	506.7	527.2	533.5	488.0	534.0	485.2
Engineering and Home Offices Services Including Fees	38.5	41.4	47.4	41.2	35.3	46.8	41.3	42.5	46.0	40.5	42.2	42.7	39.0	42.7	38.8
Project Contingency	77.9	83.8	96.0	83.5	71.4	94.8	83.7	86.1	93.1	82.1	85.4	86.4	79.1	86.5	78.6
Plant Investment - Power Plant	597.2	642.6	736.3	640.1	547.5	726.7	641.6	660.3	713.6	629.3	654.8	662.6	606.1	663.2	602.6
Plant Investment - FGD	124.1	81.9	84.4	118.2	117.2	83.4	77.4	91.0	83.2	169.2	73.7	86.2	88.9	79.6	118.9
Total Plant Investment	721.3	724.5	820.7	758.3	664.7	810.1	719.0	751.3	796.8	798.5	728.5	748.8	695.0	742.8	721.5
Owner's Cost															
Preproduction Costs	21.9	20.7	22.7	22.6	20.6	22.5	20.7	21.2	23.8	23.6	20.9	21.1	20.0	21.1	21.9
Inventory Capital	7.8	7.7	7.7	7.7	7.7	7.4	7.6	7.8	8.1	7.9	7.9	7.4	7.4	7.5	7.8
Initial Catalyst and Chemicals Charge	0.9	0.3	0.3	0.9	0.9	0.3	0.3	0.3	0.2	0.9	0.3	0.3	0.3	0.3	0.9
Allowance for Funds during Construction	119.7	120.3	136.2	125.9	110.3	134.5	119.4	124.7	132.3	132.6	120.9	124.3	115.4	123.3	119.8
Land	4.0	2.0	2.0	4.0	4.0	2.0	2.0	2.0	2.0	4.0	2.0	2.0	2.0	2.0	4.0
Total Owner's Cost	154.3	151.0	168.9	161.1	143.5	166.7	150.0	156.0	166.4	169.0	152.0	155.1	145.1	154.2	154.4
Total Capital Requirement	875.6	875.5	989.6	919.4	808.2	976.8	869.0	907.3	963.2	967.5	880.5	903.9	840.1	897.0	875.9
Total Capital Requirement Excluding Switchyard	856.7	856.6	967.4	897.9	791.1	954.6	850.1	885.4	941.3	948.6	857.6	882.4	823.0	878.1	857.0

NOTE: The estimate reflects mid-1978 price levels and mid-1980 commercial operation.

Table 6-2

ALTERNATE PLANTS-TURBINE THROTTLE STEAM 3500 PSIG
ORDER-OF-MAGNITUDE ESTIMATE SUMMARIES - ALTERNATE PLANTS
$ MILLIONS

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE NEAR	Kenosha	Kenosha	Hermiston	Bethlehem	Albany	Delta	Freeport	Freeport	Fordyce	Panora	Velva	Quincy	Dade	Mesquite	Glassford
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL SOURCE - STATE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
EMISSION STANDARDS	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	N.Mexico	EPA
PLANT MW NET - 2 EQUAL SIZE UNITS	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500
ITEM															
10 Concrete	$19.1	$19.8	$26.5	$23.0	$16.6	$22.9	$19.8	$20.0	$20.0	$19.8	$20.2	$23.0	$16.6	$19.8	$19.1
20 Civil/Structural/Architectural															
21,22,24 Structural & Misc. Iron & Steel	17.4	17.9	28.1	19.9	13.9	21.1	17.9	18.2	18.2	17.9	18.4	19.8	13.9	17.9	17.4
25 Architectural & Finish	8.7	9.0	14.1	9.8	7.0	10.4	9.0	9.2	9.2	9.0	9.3	9.8	7.0	9.0	8.7
26 Earthwork	17.4	17.9	28.1	19.8	13.9	21.1	17.9	18.3	18.3	17.9	18.4	19.8	13.9	17.9	17.4
27 Piles and Caissons	8.8	9.2	-	-	-	-	9.2	9.3	9.3	9.2	9.4	-	8.8	9.2	8.8
28 Site Improvements	11.1	11.6	17.9	12.7	9.1	17.2	16.9	17.2	35.0	28.7	14.6	14.2	14.8	14.3	15.6
30 Steam Generators	111.2	116.7	128.4	111.5	111.4	126.0	111.9	125.8	134.4	113.4	139.9	111.5	113.4	120.5	112.0
41 Turbine Generators	55.2	55.2	57.4	56.9	54.0	57.4	55.2	56.1	56.0	55.2	56.3	56.9	54.0	55.2	55.2
42 Main Condenser & Auxiliaries	4.5	4.7	5.0	4.7	4.5	4.7	4.7	4.9	4.9	4.8	5.0	4.8	4.5	4.8	4.5
43 Rotating Equipment, Ex. T/G	14.2	14.5	15.2	14.6	13.6	14.9	14.5	17.0	17.0	14.5	17.2	14.6	13.6	14.5	14.2
44 Heaters & Exchangers	4.1	4.2	4.4	4.3	3.9	4.2	4.1	4.5	4.5	4.1	4.7	4.3	3.9	4.2	4.0
45 Tanks, Drums & Vessels	1.7	1.7	1.8	1.7	1.5	1.8	1.7	1.9	1.9	1.7	1.9	1.7	1.5	1.7	1.7
46 Water Treatment/Chemical Feed	2.8	2.7	2.8	3.4	2.6	2.8	2.7	2.8	2.8	2.7	2.9	3.4	2.6	2.7	2.8
47.0 Coal/Ash/FGD Equipment															
47.1 Coal Unloading Equipment	3.7	3.9	4.7	3.8	2.7	4.1	3.9	8.7	9.3	3.9	9.4	3.7	2.4	4.7	4.0
47.2 Coal Reclaiming Equipment	3.4	3.7	3.8	3.3	1.9	3.7	3.7	-	-	3.7	-	3.4	1.9	3.7	3.1
47.3 Ash Handling Equipment	5.0	4.9	4.9	4.9	4.7	5.8	4.8	5.5	6.7	5.1	4.9	4.9	5.5	5.4	5.1
47.4 Electrostatic Precipitators	28.1	48.6	47.6	27.0	22.9	78.7	51.2	56.2	62.3	28.2	33.4	49.5	53.3	71.0	29.0
47.6 FGD Removal Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47.8 Stack (Incl. Lining, Lights, Etc.)	5.1	5.1	6.2	5.9	4.5	6.2	5.1	5.1	5.2	5.1	5.2	5.9	4.5	5.1	5.1
48 Other Mechanical Equipment Incl. Insulation & Lagging	9.1	9.7	11.5	10.0	7.8	10.6	9.7	8.0	8.9	9.7	9.0	10.0	7.8	9.7	8.5
49 Heating, Ventilating, and Air Conditioning	2.7	2.8	3.0	2.8	2.4	2.9	2.8	2.9	2.9	2.8	2.9	2.8	2.4	2.8	2.7
50 Piping	48.1	44.9	55.3	51.0	44.3	54.0	49.5	45.9	45.9	49.5	45.9	51.0	44.3	49.5	48.1
60 Control & Instrumentation	11.4	11.7	13.2	12.3	10.5	12.8	11.8	11.4	11.3	11.8	11.4	12.3	10.5	11.8	11.4
70 Electrical Equipment (Switchgear/Transformers/MCCs/Fixtures)	11.4	11.9	13.4	12.7	10.4	13.1	11.6	15.6	11.6	11.6	11.8	12.7	10.4	11.6	11.4

Table 6-2

ALTERNATE PLANTS-TURBINE THROTTLE STEAM 3500 PSIG
ORDER-OF-MAGNITUDE ESTIMATE SUMMARIES (Cont'd)
$ MILLIONS

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE NEAR	Kenosha	Kenosha	Hermiston	Bethlehem	Albany	Delta	Freeport	Freeport	Fordyce	Panora	Velva	Quincy	Dade	Mesquite	Glassford
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL SOURCE - STATE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
EMISSION STANDARDS	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	N.Mexico	EPA
PLANT MW NET - 2 EQUAL SIZE UNITS	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500
ITEM															
80 Electrical Bulk Materials															
81,82,83 Cable Tray & Conduit	12.2	12.0	14.0	13.2	11.0	14.0	12.2	10.4	10.4	12.2	10.5	13.2	11.0	12.2	12.2
84,85,86 Wire & Cable	13.6	14.1	15.9	15.0	12.4	15.6	13.9	11.1	11.1	13.9	11.2	15.0	12.4	13.9	13.6
- Switchyard	11.4	11.4	13.4	12.9	10.3	13.4	11.4	13.2	13.2	11.4	13.8	12.9	10.3	11.4	11.4
Subtotal	441.4	469.8	536.6	457.1	397.8	539.4	477.1	499.2	530.3	467.8	487.6	481.1	443.2	504.5	447.0
Field Distributables	45.2	45.7	58.6	64.7	50.5	55.5	44.4	42.7	49.7	44.9	47.8	57.7	40.8	46.5	45.0
Field Cost	486.6	515.5	595.2	521.8	448.3	594.9	521.5	541.9	580.0	512.7	535.4	538.8	484.0	551.0	492.0
Engineering and Home Office Services Including Fees	38.9	41.2	47.6	41.7	35.9	47.6	41.7	43.4	46.4	41.0	42.8	43.1	38.7	44.1	39.4
Project Contingency	78.8	83.5	96.4	84.5	72.6	96.4	84.5	87.8	94.0	83.1	86.7	87.3	78.4	89.3	79.7
Plant Investment - Power Plant	604.3	640.2	739.2	648.0	556.8	738.9	647.7	673.1	720.4	636.8	664.9	669.2	601.1	684.4	611.1
Plant Investment - FGD	121.1	79.9	82.8	116.1	115.0	81.9	75.6	89.2	80.9	166.3	72.0	84.3	87.0	77.7	116.6
Total Plant Investment	725.4	720.1	822.0	764.1	671.8	820.8	723.3	762.3	801.3	803.1	736.9	753.5	688.1	762.1	727.7
Owner's Cost															
Preproduction Costs	22.1	20.9	23.0	22.8	20.9	23.0	21.1	21.7	22.9	23.7	21.5	21.5	20.2	21.8	22.2
Inventory Capital	7.6	7.4	7.5	7.5	7.6	7.2	7.4	7.6	7.8	7.7	7.6	7.2	7.2	7.3	7.6
Initial Catalyst and Chemicals Charge	0.9	0.3	0.3	0.9	0.9	0.3	0.3	0.3	0.2	0.9	0.3	0.3	0.3	0.3	0.9
Allowance for Funds during Construction	120.4	119.5	136.5	126.8	111.5	136.3	120.1	126.5	133.0	133.3	122.3	125.1	114.2	126.5	120.8
Land	4.0	2.0	2.0	4.0	4.0	2.0	2.0	2.0	2.0	4.0	2.0	2.0	2.0	2.0	4.0
Total Owner's Cost	155.0	150.1	169.3	162.0	144.9	168.8	150.9	158.1	165.9	169.6	153.7	156.1	143.9	157.9	155.5
Total Capital Requirement	880.4	870.2	991.3	926.1	816.7	989.6	874.2	920.4	967.2	972.7	890.6	909.6	832.0	920.0	883.2
Total Capital Requirement Excluding Switchyard	861.5	851.3	969.1	904.6	799.6	967.4	855.3	898.5	945.3	953.8	867.7	888.1	814.9	901.1	864.3

NOTE: The estimate reflects mid-1978 price levels and mid-1980 commercial operation.

Table 6-3

FLUE GAS DESULFURIZATION FOR BASE PLANTS
ORDER-OF-MAGNITUDE ESTIMATE SUMMARIES
$ MILLIONS

(Subcritical Design)

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE NEAR	Kenosha	Kenosha	Hermiston	Bethlehem	Albany	Delta	Freeport	Freeport	Fordyce	Panora	Velva	Quincy	Dade	Mesquite	Glassford
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL SOURCE - STATE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
EMISSION STANDARDS	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	N.Mexico	EPA
PLANT MW NET - 2 EQUAL SIZE UNITS	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500
ALKALI TYPE	Limestone	Lime	Lime	Limestone	Limestone	Lime	Lime	Lime	Lime	Limestone	Lime	Lime	Lime	Lime	Limestone
FLUE GAS FLOW 10^3 ACFM	1,832	1,979	1,932	1,754	1,722	2,031	1,858	1,778	2,038	1,841	2,068	1,735	1,739	2,021	1,756
FLUE GAS THRU ABSORBERS	100%	76%	76%	100%	100%	76%	76%	85%	76%	100%	76%	76%	85%	80%	100%
Raw Material Receiving and Storage	3.9	2.4	2.7	3.5	3.5	2.8	2.9	4.2	2.8	5.4	1.7	2.9	4.0	2.6	3.6
Feed Preparation and Storage	6.2	2.3	2.5	5.6	5.6	2.7	2.8	4.1	2.7	8.6	1.6	2.8	3.9	2.5	5.6
Flue Gas Treatment	50.6	42.3	44.7	49.4	48.8	41.6	37.9	41.4	40.9	76.7	40.1	40.7	40.5	39.9	49.7
Flue Gas Reheat	4.2			4.1	4.0					4.2					4.1
Waste Separation	13.1	3.8	2.7	11.8	11.9	4.2	4.2	6.8	4.8	18.2	2.1	6.3	6.7	4.1	11.9
Waste Disposal	4.3	1.5	1.4	3.9	3.9	2.0	1.6	2.6	1.8	6.0	0.8	3.0	2.6	1.5	3.9
Flue Gas Supply	4.7	5.1	5.2	4.6	4.5	5.3	4.9	4.8	5.4	4.7	5.3	4.7	4.7	5.2	4.6
Total Process Capital	87.0	57.4	59.2	82.9	82.2	58.6	54.3	63.9	58.4	123.8	51.6	60.4	62.4	55.8	83.4
General Facilities	10.9	7.2	7.4	10.4	10.3	7.3	6.8	8.0	7.3	12.2	6.5	7.6	7.8	7.0	10.4
Engineering and Home Office Services Including Fees	10.9	7.2	7.4	10.4	10.3	7.3	6.8	8.0	7.3	12.2	6.5	7.6	7.8	7.0	10.4
Process Plant and General Facilities	108.2	71.8	74.0	103.7	102.8	73.2	67.9	79.8	73.0	148.2	64.6	75.6	78.0	69.8	114.2
Project Contingency	10.9	7.2	7.4	10.4	10.3	7.3	6.8	8.0	7.3	14.8	6.5	7.6	7.8	7.0	10.4
Process Contingency	4.4	2.9	3.0	4.1	4.1	2.9	2.7	3.2	2.9	6.2	2.6	3.0	3.1	2.8	4.3
Total FGD Investment	124.1	81.9	84.4	118.2	117.2	83.4	77.4	91.0	83.2	169.2	73.7	86.2	88.9	79.6	118.9

Table 6-4

FLUE GAS DESULFURIZATION FOR ALTERNATE PLANTS
ORDER-OF-MAGNITUDE ESTIMATE SUMMARIES
$ MILLIONS

(Supercritical Design)

PLANT NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE NEAR	Kenosha	Kenosha	Hermiston	Bethlehem	Albany	Delta	Freeport	Freeport	Fordyce	Panora	Velva	Quincy	Dade	Mesquite	Glassford
STATE	Wisconsin	Wisconsin	Oregon	Pennsylvania	Georgia	Utah	Texas	Texas	Arkansas	Iowa	N.Dakota	Massachusetts	Florida	N.Mexico	Illinois
COAL SOURCE - STATE	Illinois	Wyoming	Wyoming	W.Virginia	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Virginia	Alabama	N.Mexico	Illinois
EMISSION STANDARDS	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	EPA	N.Mexico	EPA
PLANT MW NET - 2 EQUAL SIZE UNITS	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500	2x500
ALKALI TYPE	Limestone	Lime	Lime	Limestone	Limestone	Lime	Lime	Lime	Lime	Limestone	Lime	Lime	Lime	Lime	Limestone
FLUE GAS FLOW 10^3 ACFM	1,832	1,979	1,932	1,754	1,722	2,031	1,858	1,778	2,038	1,841	2,068	1,735	1,739	2,021	1,756
FLUE GAS THRU ABSORBERS	100%	76%	76%	100%	100%	76%	76%	85%	76%	100%	76%	76%	85%	80%	100%
Raw Material Receiving and Storage	3.8	2.3	2.6	3.4	3.4	2.7	2.8	4.1	2.7	5.3	1.7	2.8	3.9	2.5	3.5
Feed Preparation and Storage	6.1	2.2	2.4	5.5	5.5	2.6	2.7	4.0	2.6	8.4	1.6	2.7	3.8	2.4	5.5
Flue Gas Treatment	49.3	41.5	43.9	48.6	48.0	40.8	37.1	40.6	40.1	75.4	39.3	39.9	39.7	39.1	48.9
Flue Gas Reheat	4.1			4.0	3.9					4.1					4.0
Waste Separation	12.9	3.7	2.6	11.6	11.7	4.1	4.1	6.7	4.7	17.9	2.0	6.2	6.6	4.0	11.7
Waste Disposal	4.2	1.4	1.4	3.8	3.8	2.0	1.6	2.6	1.4	5.9	0.8	2.9	2.5	1.5	3.8
Flue Gas Supply	4.6	5.0	5.1	4.5	4.4	5.2	4.8	4.7	5.3	4.6	5.2	4.6	4.6	5.1	4.5
Total Process Capital	85.0	56.1	58.0	81.4	80.7	57.4	53.1	62.7	56.8	121.6	50.6	59.1	61.1	54.6	81.9
General Facilities	10.6	7.0	7.3	10.2	10.1	7.2	6.6	7.8	7.1	12.0	6.3	7.4	7.6	6.8	10.2
Engineering and Home Office Services Including Fees	10.6	7.0	7.3	10.2	10.1	7.2	6.6	7.8	7.1	12.0	6.3	7.4	7.6	6.8	10.2
Process Plant and General Facilities	106.2	70.1	72.6	101.8	100.9	71.8	66.3	78.3	71.0	145.6	63.2	73.9	76.3	68.2	102.3
Project Contingency	10.6	7.0	7.3	10.2	10.1	7.2	6.6	7.8	7.1	14.6	6.3	7.4	7.6	6.8	10.2
Process Contingency	4.3	2.8	2.9	4.1	4.0	2.9	2.7	3.1	2.8	6.1	2.5	3.0	3.1	2.7	4.1
Total FGD Investment	121.1	79.9	82.8	116.1	115.0	81.9	75.	89.2	80.9	166.3	72.0	84.3	87.0	77.7	116.6

Table 6-5

ORDER-OF-MAGNITUDE
CAPITAL COST ESTIMATE SUMMARIES
ESCALATED TO 1985, 1990, AND 1995

BASE PLANTS

Plant Completion In	1980	1985	1990	1995
Unit 1 Commercial Operation	7-1-79	7-1-84	7-1-89	7-1-94
Unit 2 Commercial Operation	7-1-80	7-1-85	7-1-90	7-1-95
C.G. of Expenditures	7-1-78	7-1-83	7-1-88	7-1-93
Escalation at 6% per year compounded	-	33.8%	79.1%	139.7%
Plant No.		In Million $ or $/kW		
1	876	1,172	1,569	2,100
2	876	1,172	1,569	2,100
3	990	1,325	1,773	2,373
4	919	1,230	1,646	2,203
5	808	1,081	1,447	1,937
6	977	1,307	1,750	2,342
7	869	1,163	1,556	2,083
8	907	1,214	1,624	2,174
9	963	1,288	1,725	2,308
10	968	1,295	1,734	2,320
11	881	1,179	1,578	2,112
12	904	1,210	1,619	2,167
13	840	1,124	1,504	2,013
14	897	1,200	1,607	2,150
15	876	1,172	1,569	2,100

Table 6-6

ORDER-OF-MAGNITUDE
CAPITAL COST ESTIMATE SUMMARIES
ESCALATED TO 1985, 1990, AND 1995

ALTERNATE PLANTS

Plant Completion In	1980	1985	1990	1995
Unit 1 Commercial Operation	7-1-79	7-1-84	7-1-89	7-1-94
Unit 2 Commercial Operation	7-1-80	7-1-85	7-1-90	7-1-95
C.G. of Expenditures	7-1-78	7-1-83	7-1-88	7-1-93
Escalation at 6% per year compounded	-	33.8%	79.1%	139.7%
Plant No.		In Million $ or $/kW		
1	880	1,177	1,576	2,109
2	870	1,164	1,558	2,085
3	991	1,326	1,775	2,375
4	926	1,239	1,658	2,220
5	817	1,093	1,463	1,958
6	990	1,325	1,773	2,373
7	874	1,169	1,565	2,095
8	920	1,231	1,648	2,205
9	967	1,294	1,732	2,318
10	973	1,302	1,743	2,332
11	891	1,192	1,596	2,136
12	910	1,218	1,630	2,181
13	832	1,113	1,490	1,994
14	920	1,231	1,648	2,205
15	883	1,181	1,581	2,117

The table below illustrates the assumed basis for this escalation:

Plant Completion	1985	1990	1995
Unit 1 Commercial Operation	7-1-84	7-1-89	7-1-94
Unit 2 Commercial Operation	7-1-85	7-1-90	7-1-95
C.G. of Expenditures	7-1-83	7-1-88	7-1-93
Years from 7-1-78	5	10	15
Compounding factors assuming 6% escalation rate	1.338	1.791	2.397

6.10 CAPITAL COST ESTIMATES FOR TWO 1000-MW UNITS

Capital cost estimates have been prepared for plants having a net output of 2000 MW as shown in Table 6-7. Each plant will consist of two equal size units, each 1060 MW.

The plants satisfy the same conditions as the 1000-MW plants described in Section 5. The plants will be at the same sites, burn the same types of coal, and satisfy the same emissions standards.

Plant arrangements and designs will be similar to those described for the two 500-MW unit plants. The designs will include high efficiency electrostatic precipitators and spray tower absorber FGD facilities.

For the basic plant burning the Illinois coal, each boiler will be a double cavity design with a common middle wall and, like the boilers for the 500-MW units, will be a balanced draft, direct-fired pulverized coal design equipped with 11 mills, each capable of pulverizing 50 tons of coal per hour. Regenerative air heaters will be used to lower the exit gas temperature to 285°F. The boiler will deliver superheated steam at 2650 psig and 1000°F for conservatism of design and for plant reliability. Boiler reheat will also be designed for an outlet steam temperature of 1000°F.

Each turbine-generator will be a tandem-compound six flow machine with high-, intermediate-, and two low-pressure sections with a nominal rating of 1060 MW. Generators will be 3600 rpm hydrogen-cooled units designed for 1248 MVA at 0.85 power factor.

Table 6-7

ORDER-OF-MAGNITUDE
CAPITAL COST ESTIMATE SUMMARIES
PRESENT DAY PRICES (July 1, 1978)
TWO 1000-MW NET UNITS

BASE PLANTS

Plant	Region	Coal Source	$/kW
1	Great Lakes	Illinois	789
2	Great Lakes	Wyoming	789
3	Western	Wyoming	892
4	Northeastern	W. Virginia	828
5	Southeastern	Kentucky	728
6	Western	Utah	881
7	South Central	Montana	783
8	South Central	Texas	817
9	South Central	Arkansas	868
10	West Central	Iowa	872
11	West Central	N. Dakota	794
12	Northeastern	W. Virginia	815
13	Southeastern	Alabama	757
14	Western	N. Mexico	808
15	East Central	Illinois	789

The FGD unit is located between the induced draft fans and the stack. Three or more identical absorber trains will be installed in parallel for each of the two units.

Capital cost estimates given in Table 6-7 and Table 6-8 have been developed by using an exponential factor of 0.85 for the overall cost. This factor is based on data in Bechtel's historical files confirmed by a telephone quotation from a boiler supplier, the book prices for the turbine-generator, and other data. This assumes that the FGD equipment will be developed in sizes appropriate for this unit. The application of the exponential cost factor of 0.85 to estimate the 2x1000-MW power plant costs expressed in $/kW is illustrated by the following computation for Plant No. 1. Subcritical design case.

$$\$875,600,000 \times \left(\frac{2000 \text{ MW}}{1000 \text{ MW}}\right)^{0.85} \times \frac{1}{2,000,000 \text{ kW}} = 789.1 \text{ \$/kW}$$

This exponential factor is based on each 500-MW unit being increased in capacity to a 1000-MW unit and the plant remaining a twin unit facility. A different combination of units, such as 4x500 MW, will require a different exponential factor.

Table 6-8

ORDER-OF-MAGNITUDE
CAPITAL COST ESTIMATE SUMMARIES
ESCALATED TO 1985, 1990 AND 1995
TWO 1000-MW NET UNITS

BASE PLANTS

Plant Completion In	1980	1985	1990	1995
Unit 1 Commercial Operation	7-1-79	7-1-84	7-1-89	7-1-94
Unit 2 Commercial Operation	7-1-80	7-1-85	7-1-90	7-1-95
C.G. of Expenditures	7-1-78	7-1-83	7-1-88	7-1-93
Escalation at 6% per year compounded	-	33.8%	79.1%	139.7%
Plant No.	In $/kW			
1	789	1,056	1,413	1,891
2	789	1,056	1,413	1,891
3	892	1,193	1,598	2,138
4	828	1,108	1,483	1,985
5	728	974	1,304	1,745
6	881	1,179	1,578	2,112
7	783	1,048	1,402	1,877
8	817	1,093	1,463	1,958
9	868	1,161	1,555	2,081
10	872	1,167	1,562	2,090
11	794	1,062	1,422	1,903
12	815	1,090	1,460	1,954
13	757	1,013	1,356	1,815
14	808	1,081	1,447	1,937
15	789	1,056	1,413	1,891

Section 7
COMPARATIVE DATA

This section compares the estimated capital requirements presented in this report with the published costs from industry sources.

While the typical size of the estimated plants at each location is 2X500-MW units, the plants shown in Table 7-1 range from 250 MW to 1250 MW. No attempt has been made to normalize the published data either for size or for any other scope item due to unavailability of detailed information. The remaining differences may be reconciled by the completeness of the scope of each plant including initial site development, administration and service buildings, switchyards, and by the design for high reliability.

Direct comparison of published capital costs with the estimated capital requirements presented in this study should be carefully analyzed before their use.

7.1 PUBLISHED CAPITAL COSTS OF GENERATING UNITS

The results of an analysis of the capital costs of approximately 140 individual coal-fired generating units are shown in Figure 7-1. While this analysis is by no means a complete listing of units for the time period covered, it is comprehensive.

Power plant capital costs plotted in $/kW in Figure 7-1 represent the Owner's total costs of design, procurement, construction, and associated cost of money during construction (AFDC). Capital costs for generating units normally exclude transmission and distribution facilities. In addition to the scope of work performed by the engineer/constructors, capital costs also include land, licensing costs, preproduction and inventory costs, and all other project activities by the Owner such as project management, engineering, procurement, and training.

Table 7-1 shows the sources of the published costs in Figure 7-1. Data were obtained by analysis of financial reports or other publications from more than 100 utilities.

Every attempt has been made to obtain consistent data. Many units were omitted because of questionable scope, completion date, MW rating, etc. Where utility reports specifically excluded AFDC, an allowance for this cost was added.

Table 7-1

PUBLISHED CAPITAL COST OF COAL-FIRED PLANTS
(With FGD Systems)

Ref No.	Unit	State	Utility	MWe	$M	$/kW	Date of Commercial Operation	Data Source
1	Cholla 2	Ariz	APS	250	180	719	78	Prospectus 11-77 plus 15% AFDC
2	Conesville 6	Ohio	OSO	375	122	326	78	Prospectus 9-77
3	Emery 1	Utah	UPL	400	260	650	78	Prospectus 12-77
4	Mill Creek 3	Kty	LGE	425	122	287	78	Prospectus 12-76
5	Gibson 3	Ind	PSI	650	244	375	78	Prospectus 2-78
6	Jeffrey 1	Kans	KPL	680	308	453	78	Prospectus 2-78
7	Martin Lake 2	Tex	TU	750	160	213	78	Prospectus 3-78 plus 15% AFDC
8	Monticello 3	Tex	TU	750	276	368	78	Prospectus 3-78 Plus 15% AFDC
9	Brown 1	Ind	SIGE	250	136	544	79	Prospectus 12-77
10	Coronado 1	Ariz	SRP	350	364	1040	79	Annual Report '77 + 15% AFDC
11	San Juan 3	NM	TGE	466	412	884	79	Prospectus 1-78
12	Bridger 4	Wyo	PPL	500	360	720	79	Prospectus 5-77
13	Pleasants 1	WVa	APS	626	340	543	79	Annual Report 1977
14	Gibson 4	Ind	PSI	650	244	375	79	Prospectus 2-78
15	Martin Lake 3	Tex	TU	750	247	329	79	Prospectus 3-78 plus 15% AFDC
16	Cholla 4	Ariz	APS	350	247	707	80	Prospectus 11-77 plus 15% AFDC

Table 7-1 (cont.)

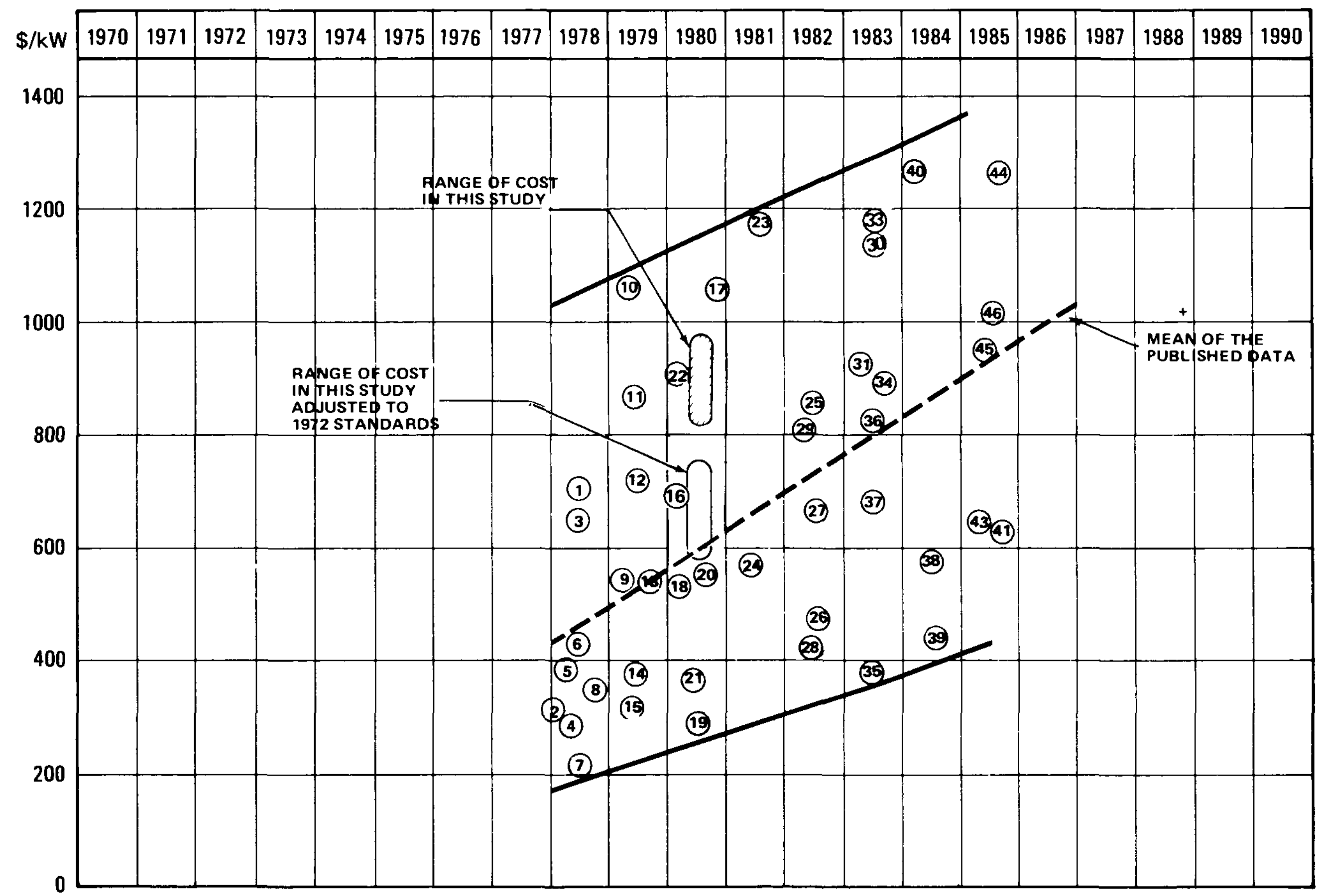
PUBLISHED CAPITAL COST OF COAL-FIRED PLANTS
(With FGD Systems)

Ref No.	Unit	State	Utility	MWe	$M	$/kW	Date of Commercial Operation	Data Source
17	Coronado 2	Ariz	SRP	350	364	1040	80	Annual Report '77 + 15% AFDC
18	Emery 2	Utah	UPL	400	213	533	80	Prospectus 12-77
19	Mill Creek 4	Kty	LGE	495	147	297	80	Prospectus 12-76
20	Pleasants 2	WVa	APS	626	340	543	80	Annual Report 1977
21	Jeffrey 2	Kans	MPS	680	245	361	80	Prospectus 3-78
22	Mansfield 3	Pa	CEI	825	733	889	80	Prospectus 4-78
23	Coyote 1	ND	MDU	410	472	1150	81	Prospectus 3-78 plus 15% AFDC
24	Newton 2	Ill	CIPS	575	333	579	81	Prospectus 12-76
25	Duck Creek 2	Ill	CIL	400	346	865	82	Prospectus 4-78
26	Petersburg 4	Ind	IPL	515	239	465	82	Prospectus 8-77
27	Gibson 5	Ind	PSI	650	447	688	82	Prospectus 2-78
28	Jeffrey 3	Kans	MPS	680	282	415	82	Prospectus 3-78
29	Colstrip 3	Mont	PGE	700	575	821	82	Prospectus 3-78
30	Cholla 5	Ariz	APS	350	398	1136	83	Prospectus 11-77 + 15% AFDC
31	Poston 5	Ohio	OSO	375	353	942	83	Prospectus 9-77
32	Emery 3	Utah	UPL	400	NA	NA	83	Prospectus 12-77

Table 7-1 (cont.)

PUBLISHED CAPITAL COST OF COAL-FIRED PLANTS
(With FGD Systems)

Ref No.	Unit	State	Utility	MWe	$M	$/kW	Date of Commercial Operation	Data Source
33	New Mexico 1	NM	PSNM	500	592	1185	83	Prospectus 2-78 plus 15% AFDC
34	Louisa 1	Iowa	IPL	650	601	925	83	Prospectus 9-77
35	Martin Lake 4	Tex	TU	750	283	378	83	Prospectus 3-78 plus 15% AFDC
36	Colstrip 4	Mont	PGE	700	575	821	83	Prospectus 3-78
37	Sherburne 3	Minn	NSP	800	554	692	83	Prospectus 2-78
38	Fast Bend 2	Kty	CCE	600	353	588	84	Prospectus 10-77
39	Jeffrey 4	Kans	MPS	680	299	440	84	Prospectus 3-78
40	PG&E Coal 1	Cal	PG&E	800	1000	1250	84	WSJ 12-29-77
41	Poston 6	Ohio	OSO	375	250	666	85	Prospectus 9-77
42	Emery 4	Utah	UPL	400	NA	NA	85	Prospectus 12-77
43	Patriot 1	Ind	IPL	650	440	677	85	Prospectus 8-77
44	PG&E Coal 2	Cal	PG&E	800	1000	1250	85	WSJ 12-29-77
45	Dickerson 4	Md	PEP	800	748	935	85	Prospectus 6-77 + 15% AFDC
46	Lake Erie 1	NY	NMP	850	859	1010	85	Prospectus 8-77 + 15% AFDC



* THE COSTS IN THIS STUDY REPRESENT A PLANT MEETING ALL REGULATIONS IN EFFECT IN MID 1978, HOWEVER THE PUBLISHED DATA FOR PLANTS IN COMMERCIAL OPERATION IN 1980 HAVE NOT BEEN REQUIRED TO MEET THESE STANDARDS BUT RATHER 1972 STANDARDS.

** *SEE TABLE 7-1 FOR DESCRIPTION OF THE LISTED PLANTS.* + *LINE REPRESENTS BEST FIT MEAN OF DATA*

Figure 7-1. Published Capital Costs of Coal-Fired U.S. Electrical Generating Units $/Net Capability kW at Initial Operation

The range of costs for the units listed in Table 7-1 is extremely wide due to the large number of variables which exist, particularly in the later projects. Some of these variables include:

- Unit kilowatt rating, design criteria, and philosophy.
- Coal quality and the range of coals to be burned.
- Ash content in the coal.
- Site features and development, type and extent of building enclosures.
- Cooling water systems design.
- First unit or added unit.
- Regulatory requirements for pollution control facilities.
- Wages and productivity of construction labor.
- Escalation.
- Schedule.

The range of $/kW costs developed falls into the upper half of the band of published data. This reflects the conservative design and full scope of plant and services considered as well as the regulatory requirements. The estimates at July 1978 cost levels represent the cost of plants having a 1980 commercial operation date. The plant design includes equipment and systems to meet regulatory requirements in effect in mid-1978. By contrast, plants listed in the published data have a design basis and the regulatory requirements of 1973 to 1976. To provide the means for comparison, the estimates were adjusted to reflect the regulatory requirements in 1972. These adjusted estimates, as shown in Figure 7-1, are approximately in the 50 to 70% range of the published cost which is considered essential for good forward planning purposes.

If a lower capital cost is desired, it may be achieved as follows:

- By deleting custom plant features.
- By reducing scope of coal- and ash-handling facilities, and storage systems.
- By eliminating plant quality features affecting plant availability and reliability.
- By choosing a site with best economic conditions.

- By reducing building areas and volume.
- By adopting a less efficient steam cycle.
- By duplicating an existing plant.
- By reducing the schedule (i.e., time spent on satisfying licensing requirements of federal, state, and local authorities or in construction).
- By changing the assumed escalation rate.

Taking into account the above areas of potential cost savings, it is possible to reduce the costs to the lower portion of the band shown in Figure 7-1.

7.2 COMPONENTS OF THE CAPITAL COSTS

Inspection of the cost estimates for the alternatives shows that there is not a single cost per kilowatt projection for a coal-fired power plant. The alternatives vary by 25%.

Figure 7-2 shows the components that make up the total cost and the variation within each component for the alternatives covered. Construction labor, which represents approximately 20% of the total cost, may vary by 50%. Labor costs are influenced by productivity experienced in different areas, availability of skilled labor, the inducements necessary to attract qualified craftsmen, and the differences in wage rates.

The boiler and turbine-generator equipment costs are approximately 15% of the total costs. The boiler cost is affected by the coal being burned and boiler efficiency is influenced by altitude and site conditions. The turbine-generator cost is affected by the turbine cycle, efficiency, and operating conditions. As shown in Figure 7-2, the costs of the boiler and turbine-generator are the most stable, therefore, least subject to potential cost reductions.

Other equipment and facilities covers all equipment and systems to support the boiler and turbine-generator including the coal- and ash-handling facilities and storage, steam, air, and water and electrical systems. This category includes 20 to 25% of the total capital cost but could vary by ± 30%. The cost of this component is influenced by the following:

- Building size.
- Coal- and ash-handling storage facilities.

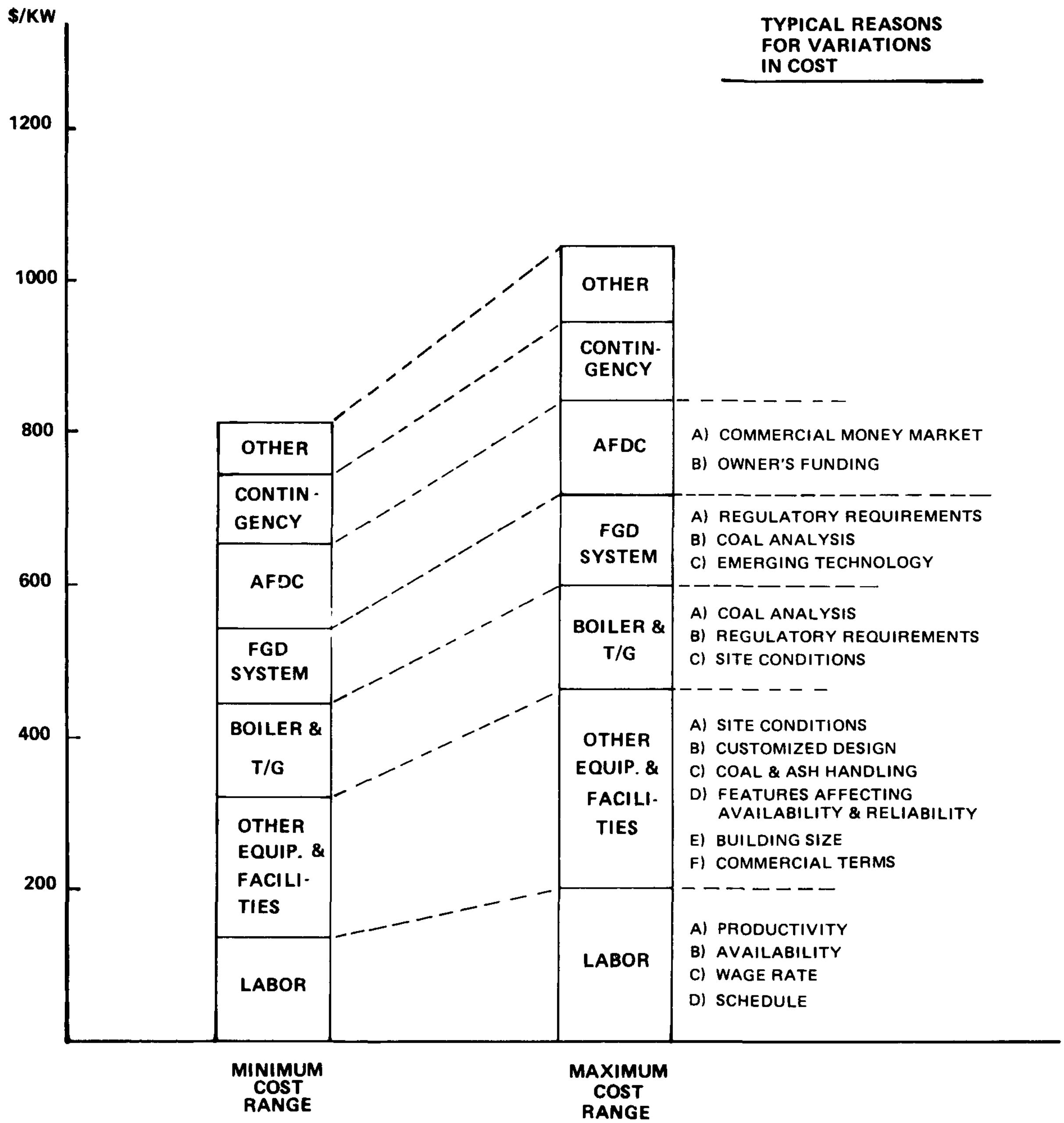


Figure 7-2. Component Costs

- Plant availability and reliability features.
- Site conditions.

Other equipment and facilities is the area of capital cost in which the utility has the most control in optimizing plant operating, maintenance, and capital cost. By reducing equipment ratings, backup systems, building size, etc, it is possible to reduce capital expenditures, but plant availability and reliability will suffer, and operating and maintenance costs may be increased.

The FGD system, approximately 15% of the project cost, is also subject to major capital cost variations for coal analysis, plant location, and the systems operating and maintenance cost. FGD is an emerging technology and particularly in light of the June 1979 NSPS, is subject to large variations in cost.

The contingency included at 15% of the capital cost is to cover additional equipment or other costs that could result when a detailed design is prepared for a definitive project at an actual site.

AFDC is a function of the cost of the above components and the utilities' cost of money and represents 16.6% of the total projected capital cost.

7.3 CONCLUSIONS

Plants with designs different from those presented here can and have been engineered by the various A/Es to meet the utility industry's varied design criteria. Figure 7-1 shows the range of variation.

All areas of plant costs are being influenced by regulatory changes, adding to equipment costs and extending design and construction time. In the early 70's, it was possible to commence construction about 12 months after start of design engineering. Regulatory and environmental considerations have expanded dramatically until it is now necessary to start licensing procedures and associated preliminary engineering as much as 3-1/2 years prior to start of construction.

Section 8

REFERENCES

The following documents and publications were used in the development of this report:

1. EPRI AF 342: - Coal-Fired Power Plant Capital Cost Estimates.

2. New Source Performance Standards of the Environmental Protection Agency - September 1978 (Proposed).

3. Cost data published in the annual financial reports of U.S. utilities.

4. EPRI RP1180-9: - Economic and Design Factors for Flue Gas Desulfurization Technology.

5. Wage rate bulletins for the U.S. construction industry.

Appendix A

ECONOMIC PREMISES

Appendix A

ECONOMIC PREMISES

TOTAL PLANT INVESTMENT

The total plant investment is the sum of:

- Process (or on-site) capital.
- General facilities (or off-site) capital.
- Engineering and home office fees.
- Project contingency.
- Process contingency.

These items are discussed below:

Process Capital

Process capital is the total constructed cost of all on-site processing and generating units including all direct and indirect construction costs. All sales taxes should be included. When possible, the process capital costs should be broken down by major plant section (e.g., fuel storage, combustion system, emission control systems, generators). The specific section breakdown should be agreed upon with the EPRI project manager. Also, if possible, the contractor should provide a breakdown of the total process capital into factory materials, field materials, and field labor.

General Facilities or Off-site Capital

The capital cost of the off-site facilities is to be given explicitly in the report. The off-site facilities include roads, office buildings, shops, laboratories, etc and generally are in the range of 5 to 20% of the on-site capital cost. Fuel, chemical, and byproduct storage systems are to be included in the on-site capital costs and are not part of the off-site facilities. The cost basis for the off-sites will be established by the contractor with the concurrence of the EPRI project manager. Sales taxes should be included where applicable.

Engineering and Home Office Overhead Including Fee

The contractor will include an estimate of the engineering and home office overhead and fee that are considered representative of this type of plant. These fees may be included in the process capital and general facility capital costs if the contractor's cost estimating system incorporates estimates of these fees as a part of the equipment costs. The capital cost summary tables must indicate where these fees have been included (10 to 15% of the process capital is typical for these fees).

Project Contingency

A capital cost contingency factor should be developed by the contractor for each major section of the plant. This is a project contingency factor that is intended to cover additional equipment or other costs that would result from a more detailed design of a definitive project at an actual site. Table A-1 presents guidelines for relating the project contingency to the level of design/estimating effort. Thus, by specifying the project contingency, the level of design/estimating effort can be defined. The contingency factors developed for each plant section should be explicitly shown in the report.

Process Contingency

This is a capital cost contingency applied to new technology in an effort to quantify the uncertainty in the design and cost of the commercial-scale equipment. The following guidelines are provided to aid in assigning process contingency allowances to various sections of the plant.

State of Technology Development	% of Installed Section Cost
New concept with limited data	25% and up
Concept with bench-scale data available	15-25%
Small pilot plant data (e.g., 1 MW size) available	10-15%
A full-size module has been operated (e.g., 20-100 MW)	5-10%
The process is used commercially	0-5%

The process contingency should be shown separately for each major plant section.

TOTAL CAPITAL REQUIREMENT

The total capital requirement for a regulated utility includes all capital necessary to complete the entire project. These items include:

Table A-1

DESIGN AND COST ESTIMATE CLASSIFICATIONS

Item	Design/ Estimate Description	Project Contingency Range	Design Information Required	Cost Estimate Basis		
				Major Equipment	Other Materials	Labor
Class I	Simplified	20% to 30%	General site conditions, geographic locations and plant layout Process flow/operation block diagram Product output capacities	By overall project or section-by-section based on capacity/cost graphs, ratio methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II	Preliminary	15% to 20%	As for Type Class I plus engineering specifics, e.g.: Major equipment specifications Preliminary P&I flow diagrams	Recent purchase costs (including freight) adjusted to current cost index	By ratio to major equipment costs on plant parameters	Labor/material ratios for similar work, adjusted for site conditions and using expected average labor rates
Class III	Detailed	10% to 15%	Complete process design. Engineering design usually 20%-40% complete. Project construction schedule. Contractual conditions and local labor conditions	Firm quotations adjusted for possible price escalation with some critical items committed Pertinent taxes and freight included	Firm unit cost quotes (or current billing costs) based on detailed quantity take-off	Estimated man-hour units (including assessment) using expected labor rate for each job classification
Class IV	Finalized	5% to 10%	As for Class III - with engineering essentially complete	As for Class III - with most items committed	As for Class III - with material on approximately 100% firm basis	As for Class III - some actual field labor productivity may be available

- Total plant investment.
- Preproduction (or startup) costs.
- Inventory capital.
- Initial chemical and catalyst charge.
- Allowance for funds during construction (AFDC).
- Land.

Total Plant Investment

Defined in Item 1 above.

Preproduction Costs

The preproduction costs are intended to cover operator training, equipment check-out, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant startup. The preproduction costs are estimated as follows:

1. One month fixed operating costs (fixed operating costs are operating and maintenance labor, administrative and support labor, and maintenance materials).
2. One month of variable operating costs at full capacity excluding fuel (these variable operating costs include chemicals, water, and other consumables and waste disposal charges).
3. 25% of full capacity fuel cost for one month (this charge covers inefficient operation that occurs during the startup period).
4. 2% of total plant investment (this charge covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity).

Inventory Capital

The value of inventories of fuel, other consumables, and byproducts is capitalized and included in the inventory capital account. The inventory capital is estimated as follows:

1. One month supply of fuel based on full capacity operation.
2. One month supply of other consumables (excluding water) based on full capacity operation.

Initial Catalyst and Chemicals Charge

The initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital) is to be included.

Allowance for Funds During Construction (AFDC)

An AFDC charge is computed based on the time period from the center of gravity (cg) of expenditures until the plant is in commercial operation. The interest rate is 8%/yr. The AFDC is then calculated from the total plant investment (TPI) as shown below:

$$AFDC = (1.08)^{cg} - 1 \quad (TPI)$$

Numerical Example

TPI = \$100

cg = 2 years

$$AFDC = (1.08)^{2} - 1 \quad (100) = \$16.6$$

The cg time period is to be estimated by the contractor. Representative centers of gravities for several types of power plants are shown below:

Type of Plant	Total Design-Construction Time	cg
Pulverized Coal-Fired (1000 MW)	5 years	2 years
Oil-Fired Combined Cycle (500 MW)	3 years	1 year
Combustion Turbine Unit (75 MW)	2 years	0.5 year

Since the AFDC charge is to be expressed in the same year dollars as the total plant investment, cost escalation (inflation) is not included.

Land

Land costs are \$5000/acre.

FIXED OPERATING COSTS

Fixed operating costs include the following:

- Operating labor.
- Maintenance (may also have a variable component).
- Overhead charges.

These items are discussed below.

Operating Labor

The contractor will estimate the number of operating jobs (OJ) that are required to operate the plant. The operating labor charges (OLC) are then computed using the average labor rate (ALR) as follows:

$$\text{OLC} = \frac{(\text{OJ}) \times (\text{ALR}) \times (8760 \text{ hr/yr})}{(\text{Full capacity of plant in kW})}$$

The average labor rate includes payroll burden and is given in Table A-2.

Maintenance Costs

Annual maintenance costs for new technologies are often estimated as a percentage of the installed capital cost of the facilities. The percentage varies widely depending on the nature of the processing conditions and the type of design. Maintenance costs in the ranges shown below are representative.

Type of Processing Conditions	Maintenance % of Process (or off-site) Capital Cost/Yr
Corrosive and abrasive slurries	6.0 - 10.0 (& higher)
Severe (solids, high pressure & temperature)	4.0 - 6.0 (& higher)
Clean (liquids and gases only)	2.0 - 4.0
Off-site facilities & steam/ electrical systems	1.5

The maintenance costs will be developed by the contractor with concurrence of the EPRI project manager. The maintenance costs should be separately expressed as maintenance labor and maintenance materials. A maintenance labor/materials ratio of 40/60 may be used for this breakdown if other information is not available.

Overhead Charges

The only overhead charge included in the power plant studies is a charge for administrative and support labor which is taken as 30% of the operating and maintenance labor.

General and administrative expenses are not included.

VARIABLE OPERATING COSTS

Consumables

Variable operating costs include fuel, water, chemicals, waste disposal, etc. The first year values to use for these items are given in Table A-2.

Table A-2

ECONOMIC VARIABLES (REFERENCE DATE 6-23-78)

Design Capacity Factor

70% for base load, 30% for intermediate load, 10% for peak load

Operating Labor (Mid-1978 $)

First year: $12.50/person hour (This labor rate is based on a direct labor charge of $9.25/hr plus a 35% payroll burden.)

Labor Inflation Rate: 6%/year

Purchased Materials (Delivered Cost), East Central Region

	Mid-1978 $	Price Escalation Rate/Yr (Including Inflation)
Fuel (Coal)	$\$1/10^6$ Btu	6.2%
Water (River)	40¢/1000 gal [b]	6.0%
Lime	$34/ton	6.0%
Limestone	$10/ton	6.0%
Disposal Charges		
Sludge	$5.70/$7.90 per ton[c] (dry basis)	6.0%
Dry, Granular Solids	$4/ton	6.0%
Waste Water	(waste water treating costs to be included in plant capital and O&M)	
Byproduct Credits		
Sulfur Acid	No credit	---
Sulfur	No credit	---
Ammonia	(a)	---(a)

Land Cost

$5000/acre

(a)To be computed.
(b)This is a raw water acquisition charge only. Intake structures, treating, and pumping costs are to be included in plant capital and O&M.
(c)$5.70 per ton for limestone FGD process and $7.90 per ton for lime FGD process.

Appendix B

ESTIMATED DETAIL INFORMATION - WAGE RATES
(MID-1978) $/MH

TABLE B-1

ESTIMATED DETAIL INFORMATION - WAGE RATES (MID-1978) $/MH**

PLANT	LOCATION	BOILERMAKER	MILLWRIGHT	CARPENTER	IRONWORKER	LABORER	PIPEFITTER	ELECTRICIAN	OPERATING ENGINEER	PAINTER	SHEETMETAL WORKER	OTHER CRAFTS
1	Kenosha, WI	14.15	13.00	12.48	14.94	11.20	14.20	14.20	13.05	12.46	13.34	12.63
2	Kenosha, WI	14.15	13.00	12.48	14.94	11.20	14.20	14.20	13.05	12.46	13.34	12.63
3	Hermiston, OR	15.30*	13.12	13.34	14.98	11.63	15.76	15.76*	13.91	11.69	16.26	13.23
4	Bethlehem, PA	15.85	12.26	11.86	14.52	8.76	13.73	13.73	15.01	10.88	14.80	11.79
5	Albany, GA	12.05	12.02	9.35	10.82	5.45	10.18	10.18	11.08	6.47	8.75	10.79
6	Delta, UT	14.65	12.20	11.45	13.30	8.62	13.40*	13.40	15.47	11.01	12.60	12.20
7	Freeport, TX	13.02	13.25	13.00	14.38	8.51	13.82	14.34	13.06	12.25	12.66	12.56
8	Freeport, TX	13.02	13.25	13.00	14.38	8.51	13.82	14.34	13.06	12.25	12.66	12.56
9	Fordyce, AR	12.35	10.43	9.93	11.00	7.21	11.28	11.31	10.95	10.20*	11.75	10.64
10	Panora, IA	14.15	11.88	11.53	12.21	9.24	13.80	14.11	12.11	11.20	12.80*	11.88
11	Velva, ND	14.15	11.88*	9.23	12.27	7.39	13.45	11.30	10.15	8.55	11.90	11.14
12	Quincy, MS	14.05	12.90	12.72	13.30	9.70	14.55	14.71	13.58	12.35	14.06	12.77
13	Dade City, FL	13.00	11.27	10.80	11.58	8.30	12.86	12.99	11.45	10.20	12.06*	11.58
14	Mesquite, NM	12.74	13.60	12.85	13.05	8.41	14.20	12.99	11.40	9.42	13.81	11.70
15	Glassford, IL	13.40	13.41	12.91	13.55	11.75	14.26	13.94	13.47	12.15	13.47	13.39

* Estimated
**Including fringe benefits

Appendix C

TYPICAL PLANT HEAT BALANCES

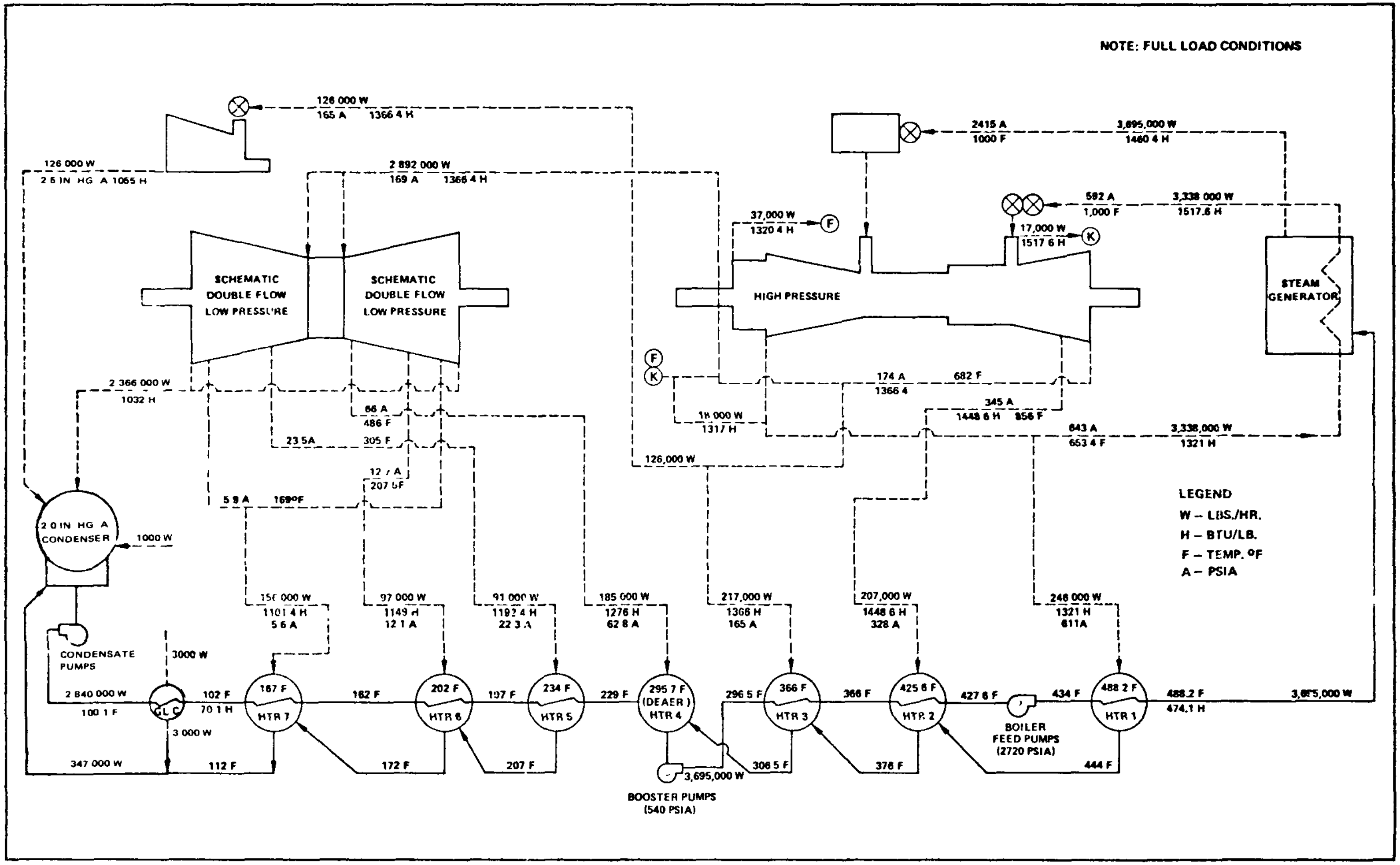


Figure C-1. Representative Steam Flow Rates and Conditions - Base Case (subcritical design)

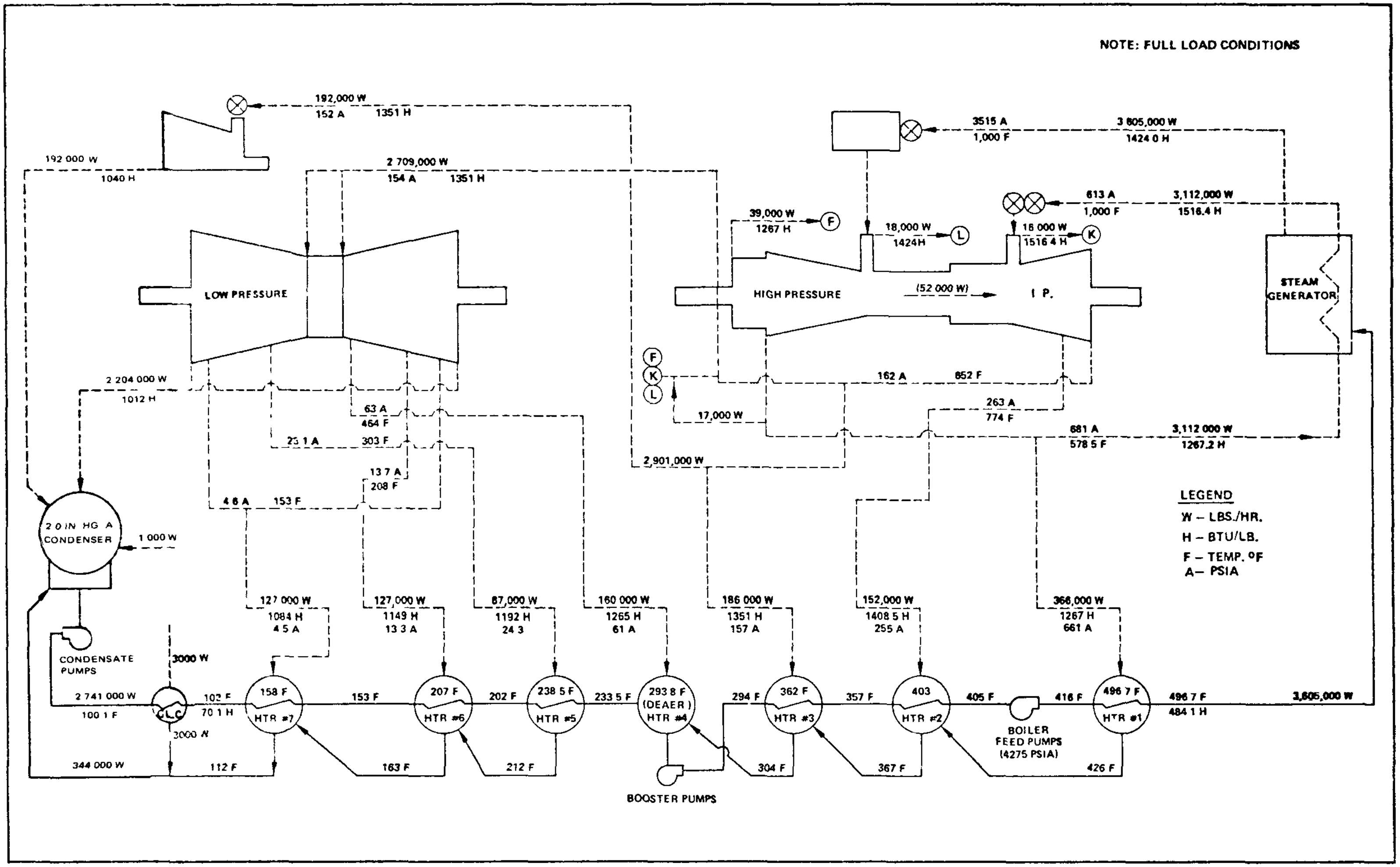


Figure C-2. Representative Steam Flow Rates and Conditions - Alternate Case (supercritical design)

Table C-1
PLANT HEAT BALANCES
BASE CYCLE - 100% LOAD

Subcritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Va.	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat RAte	Btu/kWh	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914	7,914
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/kWh	9,024	9,344	9,333	8,963	8,963	8,993	9,224	9,410	9,746	9,097	9,604	8,932	8,963	9,160	9,045
Allowance for Auxiliaries	Btu/kWh	829	685	684	801	787	689	667	699	812	840	755	621	651	709	826
Stack Gas Reheat	Btu/kWh	180	-	-	179	179	-	-	-	-	182	-	-	-	-	181
Boiler Fans	Btu/kWh	230	257	254	219	218	260	239	242	284	236	283	216	218	263	228
Coal Handling & Pulverizers	Btu/kWh	39	46	52	33	32	47	48	61	85	39	74	37	46	55	37
Other Boiler Auxiliaries(1)	Btu/kWh	186	182	178	176	164	192	181	193	233	187	192	176	193	197	184
Condensate & Booster Pumps*	Btu/kWh	60	62	62	60	60	60	61	63	65	61	64	59	60	61	60
Cooling Tower & Circ.Wtr.Pumps	Btu/kWh	114	118	118	114	114	110	118	120	124	115	121	114	114	113	116
Miscellaneous	Btu/kWh	20	20	20	20	20	20	20	20	21	20	21	19	20	20	20
Net Heat Rate	Btu/kWh	9,853	10,029	10,017	9,764	9,750	9,682	9,891	10,109	10,558	9,937	10,359	9,553	9,614	9,869	9,871

(1)Assumes combustion air heated by 40°F in steam air heaters

*Boiler feed pumps are turbine-driven

Table C-2
PLANT HEAT BALANCES
BASE CYCLE - 75% LOAD

Subcritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Va.	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat Rate	Btu/kWh	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939	7,939
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/kWh	9,052	9,373	9,362	8,991	8,991	9,022	9,253	9,440	9,777	9,125	9,635	8,961	8,991	9,189	9,073
Allowance for Auxiliaries:	Btu/kWh	900	754	750	867	861	757	734	770	899	909	825	686	716	777	892
Stack Gas Reheat	Btu/kWh	181	-	-	180	180	-	-	-	-	183	-	-	-	-	181
Boiler Fans	Btu/kWh	225	251	246	214	211	254	233	236	277	231	275	210	213	256	223
Coal Handling & Pulverizers	Btu/kWh	41	49	55	35	35	51	51	65	100	42	80	40	49	59	39
Other Boiler Auxiliaries	Btu/kWh	214	208	203	201	198	220	207	220	265	214	219	200	217	224	211
Condensate & Booster Pumps*	Btu/kWh	71	73	73	70	70	70	72	74	76	71	75	70	70	72	71
Cooling Tower & Circ.Wtr.Pumps	Btu/kWh	142	146	146	141	141	136	145	148	153	142	149	140	141	140	141
Miscellaneous	Btu/kWh	26	27	27	26	26	26	26	27	28	26	27	26	26	26	26
Net Heat Rate	Btu/kWh	9,952	10,127	10,112	9,858	9,852	9,779	9,987	10,210	10,676	10,034	10,460	9,647	9,707	9,966	9,965

*Boiler feed pumps are turbine-driven

Table C-3
PLANT HEAT BALANCES
BASE CYCLE - 50% LOAD

Subcritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.VA.	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat Rate	Btu/KWh	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210	8,210
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/KWh	9,316	9,693	9,682	9,298	9,298	9,330	9,569	9,762	10,111	9,437	9,964	9,266	9,298	9,502	9,383
Allowance for Auxiliaries:	Btu/KWh	1,087	942	939	1,050	1,030	963	920	973	1,117	1,100	1,030	862	899	969	1,082
Stack Gas Reheat	Btu/KWh	187	-	-	186	186	-	-	-	-	189	-	-	-	-	188
Boiler Fans	Btu/KWh	255	287	281	244	240	290	265	268	314	262	312	239	242	291	254
Coal Handling & Pulverizers	Btu/KWh	47	56	64	40	40	59	59	75	105	49	92	46	57	67	45
Other Boiler Auxiliaries	Btu/KWh	256	245	241	240	224	281	247	273	323	256	264	239	260	269	253
Condensate & Booster Pumps*	Btu/KWh	85	88	88	85	85	85	87	89	92	86	91	84	85	87	85
Cooling Tower & Circ.Wtr.Pumps	Btu/KWh	217	225	224	216	216	209	222	227	240	218	229	215	216	215	217
Miscellaneous	Btu/KWh	40	41	41	39	39	39	40	41	43	40	42	39	39	40	40
Net Heat Rate	Btu/KWh	10,448	10,635	10,621	10,348	10,328	10,293	10,489	10,735	11,228	10,537	10,994	10,128	10,197	10,471	10,465

*Boiler feed pumps are turbine-driven

Table C-4
PLANT HEAT BALANCES
BASE CYCLE - 25% LOAD

Subcritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Va	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat Rate	Btu/kWh	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430	9,430
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/kWh	10,753	11,133	11,120	10,680	10,680	10,716	10,991	11,213	11,613	10,839	11,444	10,643	10,680	10,914	10,777
Allowance for Auxiliaries:	Btu/kWh	1,820	1,668	1,664	1,748	1,708	1,718	1,635	1,741	1,987	1,841	1,828	1,531	1,596	1,730	1,811
Stack Gas Reheat	Btu/kWh	215	-	-	214	214	-	-	-	-	217	-	-	-	-	216
Boiler Fans	Btu/kWh	490	548	539	467	461	555	510	515	605	504	601	459	465	560	487
Coal Handling & Pulverizers	Btu/kWh	74	86	99	63	62	91	92	117	162	75	143	71	89	105	70
Other Boiler Auxiliaries	Btu/kWh	472	444	438	439	406	520	451	515	607	474	483	438	477	498	470
Condensate & Booster Pumps*	Btu/kWh	183	190	189	182	182	182	187	191	198	185	195	181	182	186	183
Cooling Tower & Circ.Wtr.Pumps	Btu/kWh	296	307	306	294	294	281	303	309	318	296	310	293	294	290	295
Miscellaneous	Btu/kWh	90	93	93	89	89	89	92	94	97	90	96	89	89	91	90
Net Heat Rate	Btu/kWh	12,573	12,801	12,784	12,428	12,388	12,434	12,626	12,954	13,600	12,680	13,272	12,174	12,276	12,644	12,588

*Boiler feed pumps are turbine-driven

Table C-5
PLANT HEAT BALANCES
ALTERNATE CYCLE - 100% LOAD

Supercritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Va.	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat Rate	Btu/kWh	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661	7,661
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat RAte	Btu/kWh	8,735	9,045	9,034	8,676	8,676	8,706	8,929	9,109	9,435	8,806	9,297	8,647	8,676	8,867	8,755
Allowance for Auxiliaries:	Btu/kWh	717	603	602	717	722	607	586	616	722	754	668	543	571	625	741
Stack Gas Reheat	Btu/kWh	175	-	-	173	173	-	-	-	-	176	-	-	-	-	175
Boiler Fans	Btu/kWh	216	241	238	205	204	244	224	227	266	221	265	202	204	246	214
Coal Handling & Pulverizers	Btu/kWh	37	43	49	31	30	44	45	57	80	37	69	35	43	52	35
Other Boiler Auxiliaries(1)	Btu/kWh	107	131	127	126	133	141	130	142	179	136	141	126	142	145	133
Condensate & Booster Pumps*	Btu/kWh	55	57	57	55	55	55	56	58	60	56	59	54	55	56	55
Cooling Tower & Circ.Wtr.Pumps	Btu/kWh	107	111	111	107	107	103	111	112	116	108	113	107	107	106	109
Miscellaneous	Btu/kWh	20	20	20	20	20	20	20	20	21	20	21	19	20	20	20
Net Heat Rate	Btu/kWh	9,452	9,648	9,636	9,393	8,398	9,313	9,515	9,725	10,157	9,560	9,965	9,190	9,247	9,492	9,496

(1)Includes allowance for 40°F temperature of air in steam air heaters

*Boiler feed pumps are turbine-driven

Table C-6
PLANT HEAT BALANCES
ALTERNATE CYCLE - 75% LOAD

Supercritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Va	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat Rate	Btu/kWh	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770	7,770
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat RAte	Btu/kWh	8,859	9,174	9,163	8,800	8,800	8,830	9,056	9,239	9,569	8,931	9,430	8,770	8,800	8,993	8,880
Allowance for Auxiliaries:	Btu/kWh	828	684	681	796	790	686	665	699	824	836	754	618	648	706	821
Stack Gas Reheat	Btu/kWh	177	-	-	176	176	-	-	-	-	179	-	-	-	-	178
Boiler Fans	Btu/kWh	216	241	236	205	202	243	223	226	265	221	264	201	204	245	214
40al Handling & Pulverizers	Btu/kWh	39	47	53	34	34	49	49	62	96	40	77	38	47	57	37
Other Boiler Auxiliaries[1]	Btu/kWh	167	160	156	154	151	172	160	172	216	167	172	153	170	176	164
Condensate & Booster Pumps*	Btu/kWh	67	69	69	66	66	66	68	70	72	67	71	66	66	68	67
Cooling Tower & Circ.Wtr.Pumps	Btu/kWh	136	140	140	135	135	130	139	142	147	136	143	134	135	134	135
Miscellaneous	Btu/kWh	26	27	27	26	26	26	26	27	28	26	27	26	26	26	26
Net Heat Rate	Btu/kWh	9,687	9,858	9,844	9,596	9,590	9,516	9,721	9,938	10,393	9,767	10,184	9,388	9,448	9,699	9,701

*Boiler feed pumps are turbine-driven

Table C-7
PLANT HEAT BALANCES
ALTERNATE CYCLE - 50% LOAD

Supercritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Va.	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat Rate	Btu/kWh	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130	8,130
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/kWh	9,270	9,599	9,587	9,207	9,207	9,239	9,476	9,667	10,012	9,345	9,867	9,176	9,207	9,410	9,291
Allowance for Auxiliaries:	Btu/kWh	1,027	883	880	990	970	903	862	914	1,054	1,040	969	804	841	909	1,022
Stack Gas Reheat	Btu/kWh	185	-	-	184	184	-	-	-	-	187	-	-	-	-	186
Boiler Fans	Btu/kWh	250	281	275	239	235	284	260	263	308	257	306	234	237	285	249
Coal Handling & Pulverizers	Btu/kWh	46	55	63	39	39	58	58	74	103	48	90	45	56	66	44
Other Boiler Auxiliaries	Btu/kWh	212	201	197	196	180	236	203	228	277	212	220	195	216	224	209
Condensate & Booster Pumps*	Btu/kWh	81	84	84	81	81	81	83	85	88	82	87	80	81	83	81
Cooling Tower & Circ.Wtr.Pumps	Btu/kWh	213	221	220	212	212	205	218	223	235	214	224	211	212	211	213
Miscellaneous	Btu/kWh	40	41	41	39	39	39	40	41	43	40	42	39	39	40	40
Net Heat Rate	Btu/kWh	10,297	10,482	10,467	10,197	10,177	10,142	10,338	10,581	11,066	10,385	10,836	9,980	10,048	10,319	10,313

*Boiler feed pumps are turbine-driven

Table C-8
PLANT HEAT BALANCES
ALTERNATE CYCLE - 25% LOAD

Supercritical Design

CASE NO.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
SITE LOCATION																
COAL SOURCE - STATE		Illinois	Wyoming	Wyoming	W. Va.	Kentucky	Utah	Montana	Texas	Arkansas	Iowa	N.Dakota	W.Va.	Alabama	N.Mexico	Illinois
- COUNTY		St. Clair	Campbell	Campbell	Harrison	Hopkins	Carbon	Rosebud	Milam	Dallas	Mahaska	Ward	Logan	Walker	San Juan	No. 6
COAL HEATING VALUE	Btu/lb	10,100	8,020	8,150	11,510	12,130	9,650	8,570	7,400	5,790	9,450	6,670	11,680	9,450	8,250	9,860
COAL MOISTURE VALVE	%	12.0	30.4	30.5	8.0	8.2	9.5	25.5	31.0	37.7	15.7	38.7	6.6	8.5	19.0	12.6
PLANT NET OUTPUT (Rated)	MW	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
NO. OF UNITS	MW	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
UNIT NET OUTPUT (Rated)	MW	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Steam Cycle Heat Rate	Btu/kWh	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240	9,240
Boiler Efficiency	%	87.7	84.7	84.8	88.3	88.3	88.0	85.8	84.1	81.2	87.0	82.4	88.6	88.3	86.4	87.5
Gross Heat Rate	Btu/kWh	10,536	10,909	10,896	10,464	10,464	10,500	10,769	10,987	11,379	10,621	11,214	10,429	10,464	10,694	10,560
Allowance for Auxiliaries:	Btu/kWh	1,665	1,516	1,511	1,595	1,557	1,563	1,484	1,585	1,821	1,685	1,668	1,383	1,445	1,575	1,656
Stack Gas Reheat	Btu/kWh	211	-	-	209	209	-	-	-	-	212	-	-	-	-	211
Boiler Fans	Btu/kWh	470	526	517	448	443	533	490	494	581	484	577	441	446	538	468
Coal Handling & Pulverizers	Btu/kWh	71	83	95	61	60	87	88	112	156	72	137	68	85	101	67
Other Boiler Auxiliaries	Btu/kWh	367	340	334	335	303	413	347	408	496	369	377	334	372	392	365
Condensate & Booster Pumps*	Btu/kWh	172	179	178	171	171	171	176	180	186	174	183	170	171	175	172
Cooling Tower & Circ.Wtr.Pumps	Btu/kWh	284	295	294	282	282	270	291	297	305	284	298	281	282	278	283
Miscellaneous	Btu/kWh	90	93	93	89	89	89	92	94	97	90	96	89	89	91	90
Net Heat Rate	Btu/kWh	12,201	12,425	12,407	12,059	12,021	12,063	12,253	12,572	13,200	12,306	12,882	11,812	11,909	12,269	12,216

*Boiler feed pumps are turbine-driven

Appendix D

FGD SYSTEM PERSPECTIVE

Appendix D

FLUE GAS DESULFURIZATION SYSTEM PERSPECTIVE

Regulatory restrictions on emissions have necessitated continued development of the flue gas treating technologies. Emission control technology is at present the subject of intensive research and development in the United States and in other industrialized nations.

Approximately 100 processes have been examined and of these some 20 to 30 are considered to have more promise. It is outside the scope of this report to discuss the relative merits of the processes. From this report, model designs have been made for some of the most promising processes. These are summarized below. A considerable amount of development work is underway and those reported below have made significant progress. Other processes not yet at this stage of development also show considerable promise. Examples of these are Saarberg-Holter, Dowa, co-current scrubbing, A-I Aqueous Carbonate.

FGD PROCESS SELECTION CRITERIA

The following factors might be selected to identify FGD processes that will eventually see use in coal-fired power plants:

- Development status.
- Process performance.
- Utilities and raw material requirements.
- Process operability and reliability.
- Environmental impact.
- Effect on the power plant design.
- Cost factors.

PROMISING FGD SYSTEMS

Wet Throwaway Processes

Limestone. Wet slurry absorption process producing sludge requiring fixation or stabilization.

This is the most developed of all FGD systems. Its feed material is widely available and the process can accommodate changes in load and sulfur content but the control response is sluggish. A major concern is the need for sludge fixation for acceptable waste disposal. Modifying the process to include forced oxidation can eliminate the need for fixation and addition of magnesia can improve control response.

Lime. Wet slurry absorption process producing sludge requiring fixation or stabilization.

This process is similar to the limestone process in its state of development and application. The increased reactivity of the lime slurry permits higher alkali utilization which reduces the volume of waste produced. The cost of alkali preparation for lime is also less than that for limestone. These factors all tend to reduce the cost of lime scrubbing relative to limestone. For this reason, the lime process has been evaluated for the low sulfur application and the limestone for the high sulfur coal.

Double Alkali. Wet sodium sulfite absorption process using lime to regenerate the spent absorbent to yield a calcium sulfite/sulfate sludge requiring fixation. The dilute mode system has been applied in the United States to an industrial boiler and is considered commercially developed. Its complexity probably will limit its future use to specialized small scale applications. The concentrated mode system is offered by a number of vendors and is considered commercially developed. This particular process was extensively piloted in coal-fired service at a scale of 25 MW. A major 227-MW utility application is nearing completion.

Chiyoda 121. A wet slurry limestone process employing a sparged vessel absorber/ oxidizer to produce gypsum. Tests were initated at the bench and laboratory scale in 1975 and a 23-MW pilot plant at Gulf Power Company's Scholz power plant started up in mid-1978. Some preliminary results are currently being reported by EPRI.

Dry Throwaway Process

Spray Dryer/Fabric Filter (Lime). Producing a combined waste of fly ash and low solubility calcium salts.

All of the components required for this system are commercially available from a number of suppliers. Several significant pilot plant tests on flue gas were conducted during 1977 and 1978. One supplier considers the lime recycle feature proprietary and has applied for a patent on it. The available test data are for low sulfur (to 1.5%) coal. Some testing has been done on flue gas from a utility boiler firing low sulfur coal supplemented by bottled SO_2 to simulate flue gas produced by burning high sulfur coal.

The spray dryer will generally be combined with a downstream baghouse for both particulate and SO_2 removal. Extensive pilot plant testing confirms that the baghouse will remove both fly ash and oxides of sulfur. SO_2 removal as high as 98% has been reported when injection takes place ahead of the air preheater at a gas temperature of $545^{\circ}F$. Work is continuing on this technique. Baghouses have a number of good features when compared to precipitators:

- High collection efficiency.
- High collection efficiency of particles smaller than 3 microns.
- On-line maintenance without reducing load.
- Ability to remove oxides with suitable additions.
- Stepless turndown.
- Turndown from 0 to fan capability.

There are also disadvantages such as pressure drop of 5 in. of water column greater than that of a precipitator and repórted variations in bag life.

Wet Regenerable Processes

Wellman-Lord. Wet sodium sulfite absorption employing steam regeneration to liberate SO_2 for separate conversion to sulfuric acid or sulfur. This process applies SO_2 absorption in a wet medium from which the SO_2 is regenerated in concentrated form by steam stripping. Its chief disadvantages are the large heat consumption for stripping the need for a purge of sodium sulfate salt and the logistics of handling the concentrated SO_2. Conversion to elemental sulfur can also be accomplished using natural gas as a reductant. Improvements in system economics by reduction of system pressure drop and absorbent regeneration heat consumption may also be possible.

Magnesia Slurry. Wet magnesium sulfite hydroxide slurry absorption. The resulting salt is dried and regenerated by calcination. The resulting SO_2 is converted separately to sulfuric acid. This process has been tested at the 120-MW scale on a coal-fired utility boiler. Current testing is aimed at resolving problems in the areas of temperature control in the fluid bed calcine to avoid "dead burning" of regenerated MgO, slaking of regenerated MgO, and control of MgO fugitive losses.

The magnesia slurry process is based on well-understood process technology and uses commercialized equipment in all subsystems. Performance of the prototype plants has been generally satisfactory, demonstrating SO_2 removal capabilities of at least 90%. However, the numerous mechanical problems encountered in the operation of the prototype has kept the magnesia slurry process from attaining full commercialization.

Absorption/Steam Stripping. Wet absorption employing steam stripping regeneration to recover SO_2. Extensive pilot plant testing has been done on smelter tail gas with high SO_2 levels in Sweden, but the process has not yet been applied to utility boiler flue gas.

EPRI/TVA are procuring equipment for a 1-MW pilot plant to be located at the TVA's Colbert steam plant at Muscle Shoals, Alabama.

Capital Cost Estimates

EPRI, under a separate contract, employed Bechtel to prepare cost estimates for eight FGD systems. The referenced document examines the design and economic factors for the processes earlier discussed here.

The basis of the estimates is the 1978 proposed NSPS and is presented in detail in the referenced study. A summary of the capital cost estimates is presented in Figure D-1.

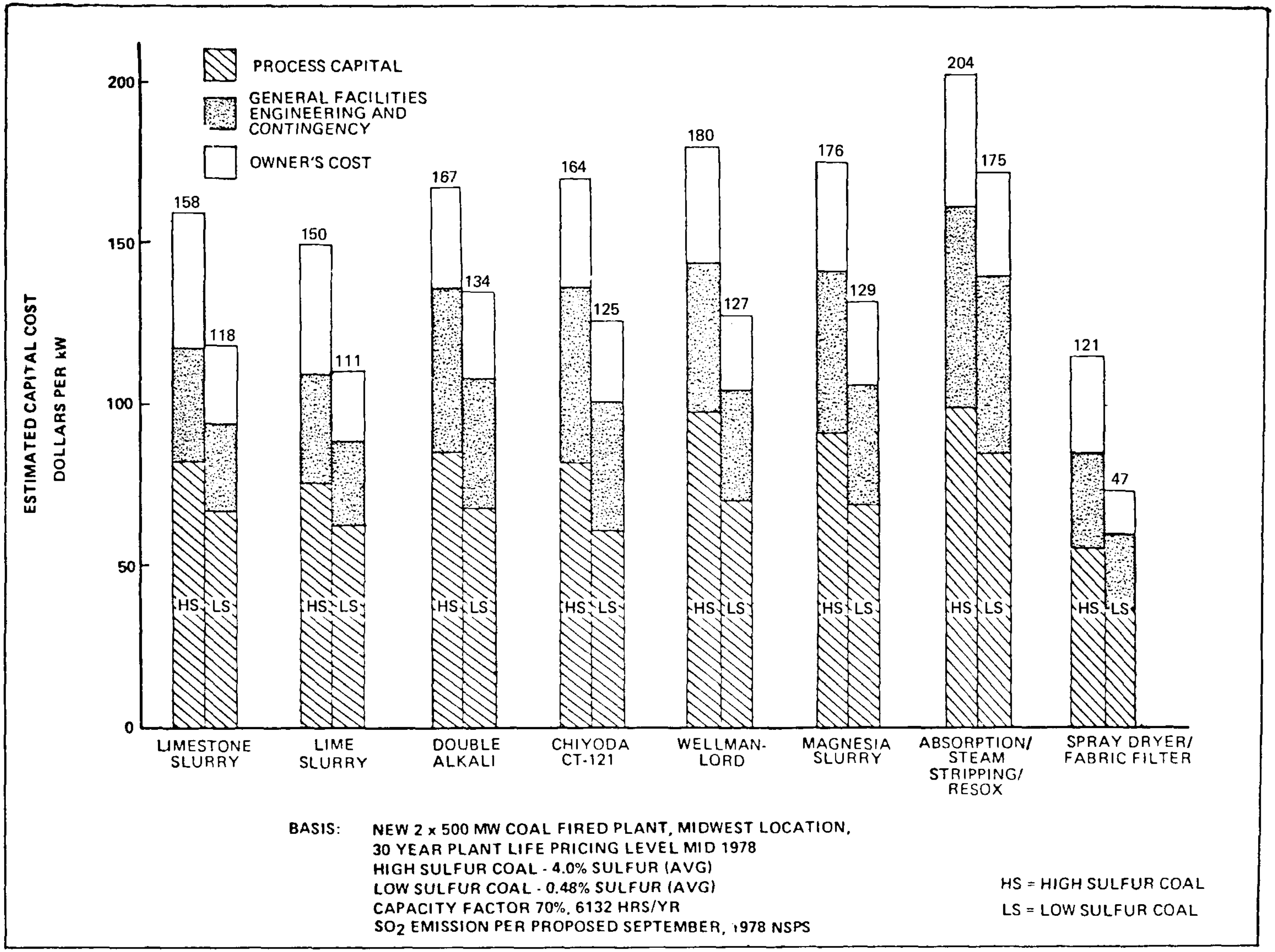
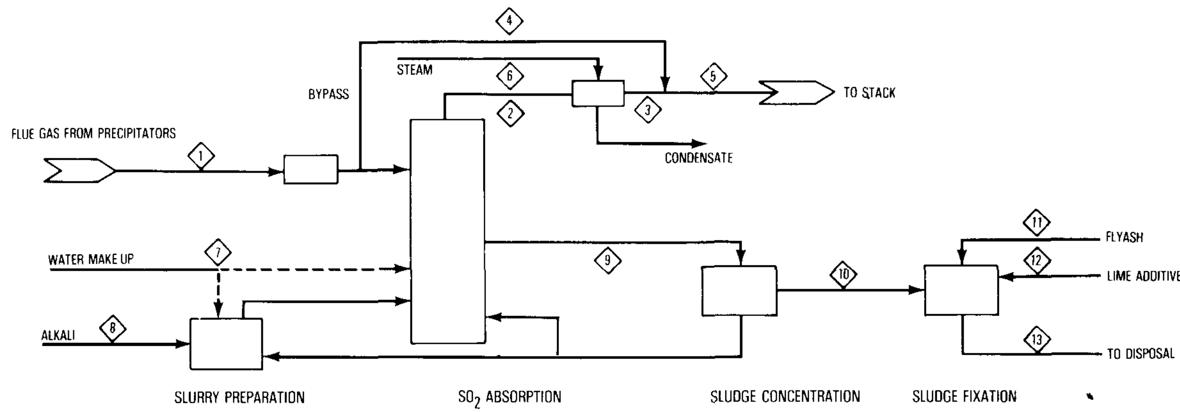


Figure D-1. Flue Gas Desulfurization Estimated Capital Cost

Appendix E

FGD SYSTEM MATERIAL BALANCE



CASE \ STEAM NO.	UNIT SIZE MW	ALKALI TYPE	FLUE GAS FEED MLB/HR ⟨1⟩	FLUE GAS TREATED MLB/HR ⟨2⟩	FLUE GAS REHEATED MLB/HR ⟨3⟩	FLUE GAS BYPASS MLB/HR ⟨4⟩	FLUE GAS STACK MLB/HR ⟨5⟩	REHEAT STEAM MLB/HR ⟨6⟩	MAKE UP WATER MLB/HR ⟨7⟩	ALKALI ADDITION LB/HR ⟨8⟩	SLURRY BLEED MLB/HR ⟨9⟩	DEWATERED SLUDGE MLB/HR ⟨10⟩	FLYASH MLB/HR ⟨11⟩	LIME ADDITIVE MLB/HR ⟨12⟩	FIXED SLUDGE MLB/HR ⟨13⟩	SO_2 CREDIT LB/HR	SO_2 FG FEED LB/HR	SO_2 EMITTED LB/HR
1	500	LIMESTONE	5,888 7	6,106 4	6,112 5	–	6 112 5	95 1	334 3	71 700	607 9	182.2	62 3	4 9	249 3	1,951	37,075	3,903
2	500	LIME	6,186 4	4 875 3	–	1 484 7	6 364 8	–	197 5	4,420	132 0	23 5	31 9	1 1	56 4	300	5,702	1,801
3	500	LIME	6 012 5	4 740 3	–	1 443 0	6 188 0	–	188 0	2,890	86.9	15 4	28 3	0 9	44 6	197	3,735	1,180
4	500	LIMESTONE	5 683 1	5 896 0	5 901 9	–	5,901 9	91 4	301 5	52,500	451 0	135.2	50 7	3 7	189 6	1,434	27,239	2,929
5	500	LIMESTONE	5,597 2	5 807 0	5,812 8	–	5,812 8	91 9	293 8	49,800	426 7	128 0	26 1	3 1	157.2	1,366	25,963	2,925
6	500	LIME	5,538 2	4 367 1	–	1,329 2	5 700 7	–	183 2	4,730	144 7	25 4	91 8	2 3	119 5	321	6,100	1,926
7	500	LIME	5,937 1	4 680 0	–	1 424 9	6 109 6	–	194 5	5,100	152 5	27 1	41 6	1 4	70 0	346	6,579	2,078
8	500	LIME	5,606 9	4,927 4	–	846 6	5,778 9	–	219 5	11 120	330 4	58 6	49 0	2.2	109 8	676	12,848	3,033
9	500	LIME	6,215 1	4,892 6	–	1 491 6	6,389 1	–	199 9	5,900	181 9	31 8	132 0	3 3	166 0	401	7,622	2,407
10	500	LIMESTONE	5 813 0	6,014 3	6,020 3	–	6 020 3	93 5	416 9	136,000	1 195 4	345 6	63 4	8 2	417 2	3,628	68,931	5,960
11	500	LIME	6,259 5	4,933 0	–	1,502 3	6,440 3	–	192 7	2 750	82 9	14 7	34 1	1 0	49 8	186	3,541	1,118
12	500	LIME	5,596 6	4,415 1	–	1,343 2	5,762 7	–	188 2	5 120	153 8	27.2	52 3	1 6	81 1	348	6,604	2,086
13	500	LIME	5,582 3	4,908 1	–	848 5	5 761 5	–	223 2	10,530	309 0	54 5	109 9	3 3	167 7	641	12,178	2,884
14	500	LIME	5,843 9	4,827 5	–	1,192 2	6,024 5	–	201 6	4,790	147 0	25 8	93 2	2 4	121 3	311	5,909	1,678
15	500	LIMESTONE	5,695 4	5,904 2	1,192 2	-	5,910 0	92 3	312 7	62,380	535 5	160 5	65 9	4 5	230 9	1,697	32,241	3,394

Figure E-1. Wet Alkali Scrubbing System - Full Load, Average Coal Sulfur

Table E-1

MATERIAL BALANCE

Plant No.		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
BASE CYCLE - 100% LOAD																
Boiler Makeup Water	10^3 lbs/hr	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Boiler Blowdown	10^3 lbs/hr	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
Cooling Tower Makeup	10^3 lbs/hr	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300	2300
Cooling Tower Blowdown	10^3 lbs/hr*	285	285	285	285	285	285	285	285	285	285	285	285	285	285	285

*Assumes makeup water TDS of 400 ppm varies with actual TDS.

ALTERNATE CYCLE - 100% LOAD																
Boiler Makeup Water	10^3 lbs/hr	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3
Boiler Blowdown	10^3 lbs/hr	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3	<3
Cooling Tower Makeup	10^3 lbs/hr	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230	2230
Cooling Tower Blowdown	10^3 lbs/hr**	275	275	275	275	275	275	275	275	275	275	275	275	275	275	275

**Assumes 400 ppm TDS makeup water to cooling tower.