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PFB
COAL FIRED COMBINED CYCLE DEVELOPMENT PROGRAM

COMMERCIAL PLANT ECONOMIC ANALYSIS (TASK 1.6)

Prepared for the

UNITED STATES DEPARTMENT OF ENERGY

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GENERAL ELECTRIC

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EXECUTIVE SUMMARY AND CONCLUSIONS

The General Electric Company was awarded, in 1976, a prime DOE Contract No. EX-76-C-01-2357, --- "CFCC Development Program." The objectives of this program are to evaluate the Coal Fired Combined Cycle (CFCC) power plant conceptual design and to conduct supporting development programs for pressurized fluidized bed (PFB) technology advancement in combustion/steam generator, gas turbine and hot gas cleanup technologies.

The Coal-Fired Combined Cycle (CFCC) is the unique power plant concept developed under the leadership of the General Electric Company to provide a direct coal-burning gas turbine and steam turbine combined cycle power plant. The advantages of the combined cycle for higher efficiency and the potential of the pressurized fluidized bed (PFB) combustor improvements in emissions could offer a new and attractive option to the electric utility industry after its successful development. The CFCC approach provides for cooling the fluid bed combustor through the use of steam tubes in the bed, which supply a steam turbine generator. The partially cooled combustion gases exiting from the combustor drive a gas turbine generator after passing through a hot gas cleanup train. This approach has been undergoing evaluation and development since January 1974 by a study team representing the General Electric Company, the Foster Wheeler Development Corporation, the Exxon Research and Engineering Company, and the coal Utilization Research Laboratory of the National Coal Board (U.K.).

The Conceptual CFCC Commercial Plant has been defined in CFCC Task 1.2 Report No. FE-2357-28. This design, being conceptual in nature, has not been improved through the formal cost reduction iteration/design program. An economic analysis of this baseline plant is provided in this report.

> Based on the economic analysis results, the General Electric Company believes that the combustion of coal by the pressurized fluidized bed process is one of the most effective and efficient means for the utilization of coal with respect to both environmental considerations and the cost of electricity.

CFCC PLANT COST ESTIMATES

The CFCC plant installed capital cost and cost of electricity estimate range was determined by the three different costing procedures, namely, the ECAS method, (originally used in a DOE sponsored study on Energy Conversion Alternatives in 1975-76), the Stearns-Rogers Engineering (SRE) method, and our GE Installation & Service Engineering (I&SE) method. In these estimates, major component costs as obtained from equipment vendors are the same; only the direct materials cost, direct labor cost, and indirect cost have been estimated by the various analyses. Independent estimates of CFCC direct materials costs, direct labor cost, and indirect cost were obtained to provide a basis of comparison. The point to note is that the range of installed capital cost is an indicator of degree of "differences in costing methodology," not as an "accuracy indication." Accuracy is a function of the degree of design detail.

	ECAS	SRE	I&SE
CFCC Plant Installed Cost ($/kw - 1984)	1023	964	925
CFCC Cost of Electricity - 80% Capacity Factor (mils/kwhr - 1984)	40.5	39.0	38.0

The assessment of plant cost at any point during the design process is imprecise in nature. Variations in component cost, labor estimates, materials, A&E services, fees, etc., add to the uncertainty. In cost of electricity estimates, additional variations could be introduced through differences in feedstock cost assumptions, O&M costs, and fixed charge rate. In the CFCC study, component cost, feedstock, O&M, and fixed charged rates were invarient among the estimates.

> Cost estimates for advanced plants are imprecise and vary with cost model, and methodology applied. The CFCC plant installed cost varied 10% and cost of electricity varied 6% using several estimating methods.

COMPARISON OF CFCC WITH ECAS-PFB

The most comprehensive cost analysis of advanced generation options performed to date was the Energy Conversion Alternatives Study, performed in 1975-76 under DOE sponsorship. Hence, any new cost estimate tends to be compared to the ECAS baseline. However, a direct comparison of the ECAS-PFB cost estimate with the CFCC cost estimate is difficult.

- The ECAS-PFB was synthesized on the basis of a net 903.8MWe output while the CFCC design is at 658MWe.

- The ECAS-PFB assumed mid-1975 start of construction with five year construction schedule while the CFCC assumed mid-1978 start of the five year period.

After modifying the ECAS-PFB reported cost to reflect these changes, direct comparison is possible.

	ECAS-PFB SCALED TO 658 MWe	CFCC, COSTED USING ECAS ASSUMPTIONS	PERCENT VARIANCE
Plant Installed Cost ($/kw - 1984)	925	1023	10
Cost of Electricity - 80% Capacity Factor (mils/kwhr - 1984)	37.2	40.5	8

This respective 10 and 8 percent difference can be traced to the evolving nature of the design concept, and is in addition to variations resulting from the cost model and methodology applied. The ECAS-PFB estimate represents status at the point of a highly conceptual design, the initial estimate - with all the optimistic assumptions involved in early stages of idea generation. The Current CFCC estimate can be considered as indicative of the first output of engineering evaluation to be an all-up system but with no systematic design/cost improvements.

CONVENTIONAL STEAM PLANT COST ESTIMATES

To further assess the variability in plant costs, several sources of cost estimates for conventional steam plants with current regulation stack gas scrubbing were investigated. Although direct comparison is difficult due to the use of different sized plants, different locations, and different times of construction, the application of a constant escalation factor (6.5%) and plant size scaling to all the data improves comparison. The conventional steam plants quoted here have been designed for sulfur control to about 1.2 lbs/10^6 Btu.

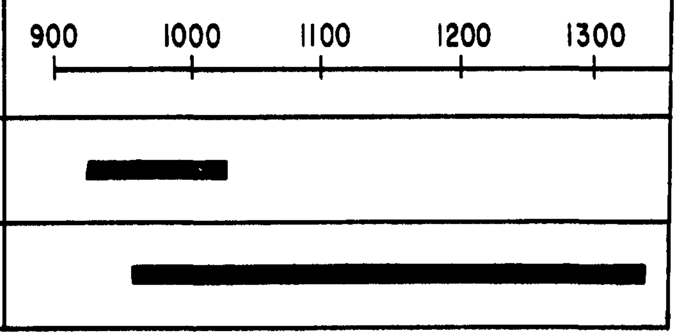
SOURCE	Installed Cost $/kw-1984 658 MWe
Burns & Roe Study	
Eastern	1213
Western	1168
EPRI Technology Assessment Guide	
Southeast	1086
East Central	1266
North East	1333
ECAS Study	40%
250° Stack	1028
175° Stack	958

> Estimated installed costs for conventional steam plants show a variability of up to 40% due to differences in location, design concept and cost estimating methodology

COMPARISON OF CFCC WITH CONVENTIONAL TECHNOLOGY

The CFCC plant has been designed to achieve 85-90% sulfur retention, 0.2 lb/10^6 BTU NO_x and 0.025 lb/10^6 BTU particulate emissions. A comprehensive cost estimate for a conventional pulverized coal plant with similar environmental performance has not been identified. Bearing in mind this environmental advantage for the PFB system, it is seen that the CFCC cost data compare favorably with conventional steam plants.

ENVIRONMENTAL VARIABLES	SO_2	NO_x	PARTICULATES	PLANT INSTALLED COST ($/kW-1984)
CFCC	85-90% (REMOVED)	2#/ 10^6 BTU	.025#/ 10^6 BTU	
CONVENTIONAL STEAM	1.2#/ 10^6 BTU	.6#/ 10^6 BTU	.1#/ 10^6 BTU	



ENVIRONMENTAL VARIABLES	SO_2	NO_x	PARTICULATES	COST OF ELECTRICITY (MILS/kWHR-1984) 35 40 45 50
CFCC	85-90% (REMOVED)	.2#/ 10^6 BTU	.025#/ 10^6 BTU	
CONVENTIONAL STEAM	1.2#/ 10^6 BTU	.6#/ 10^6 BTU	.1#/ 10^6 BTU	

The CFCC cost data compare favorably with existing technology conventional steam plants. Considering the increased costs for conventional plants to achieve the more restrictive New Source Performance Standards, significant cost advantage for the PFB technology is evidenced.

Section I

INTRODUCTION

The Coal-Fired Combined Cycle (CFCC) is the unique power plant concept developed under the leadership of the General Electric Company to provide a direct coal-burning gas turbine and steam turbine combined cycle power plant. The advantages of the combined cycle for higher efficiency and the potential of the pressurized fluidized bed (PFB) combustor for improvements in emissions could offer a new and attractive option to the electric utility industry after its successful development. The CFCC approach provides cooling of the fluid bed combustor through the use of steam tubes in the bed, which supply a steam turbine generator. The partially cooled combustion gases exiting from the combustor drive a gas turbine generator after passing through a hot gas cleanup train. This approach has been evaluated, beginning in January 1974, by a study team representing the General Electric Company, the Foster Wheeler Development Corporation, the Exxon Research and Engineering Company and the Coal Utilization Research Laboratory of the National Coal Board (UK). On the basis of these previous studies, GE was awarded, in 1976, a prime DoE contract No. EX-76-C-01-2357, called "CFCC Development Program".

The objectives of the CFCC Development Program are (a) to evaluate the CFCC power plant conceptual design, (b) to conduct supporting development program for PFB technology advancement in combustion/ steam generator, gas turbine technology, hot gas cleanup equipment and (c) to provide a back up concept program for near term PFB commercialization. The definition of this conceptual commercial plant is described in the Final Report on the Commercial Plant Concept report No. FE-2357-42. A companion commercial plant economic analysis has been performed to assess the cost status of the reference plant, to identify potential for future cost reduction efforts and to provide a baseline cost evaluation for the evolving design concept.

To achieve these objectives, the baseline commercial plant design was subject to a cost estimating utilizing three techniques. The first followed the model originally utilized in the ECAS* study. Additionally, an independent evaluation was performed by Stearns-Roger Engineering (SRE) while a third estimate was provided by the Installation and Service Engineering Business Division (I&SEBD) of General Electric.

The cost of conventional pulverized coal fired generation was developed for point of comparison through use of the data provided in the EPRI Technical Assessment Guide [1], the ECAS Study [2], and the

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* All reference to "GE-ECAS" in this report refer to the Energy Conversion Alternatives Study, an Evaluation performed by General Electric in 1975-1976 and reported in References 2 and 3.

Burns & Roe Study.[7] This comparison with existing conventional steam plants however, does not include consideration of the more favorable environmental performance of the CFCC. The existing conventional steam plants generally achieve 1.2#/10^6 BTU sulfur emission and current NO_x limits while the CFCC plant can be expected to obtain 90% sulfur retention and a factor of three reduction in NO_x emissions.

Section II

CFCC COST ESTIMATES

This section describes the basic assumptions leading to installed capital cost summaries of the CFCC conceptual commercial plant using three different estimating procedures. These procedures are the Stearns-Roger Engineering (SRE) method, the ECAS method and the Installation and Service Engineering (I&SE) method. Each of these procedures has its own basic assumptions for direct cost, indirect cost and O&M cost. The cost numbers reported here by using the SRE method and GE ECAS method are the numbers provided to GE by Stearns-Roger Engineering under a GE subcontract. The objective of placing a subcontract was to obtain an independent cost estimate and thus provide a basis for comparison with the GE I&SEBD method for estimating direct materials cost, direct labor cost and indirect cost. Major component costs for all three estimates were provided by GE in the year mid 1978 dollars and were based upon vendor quotes. Direct and indirect costs were estimated by the three estimators in mid 1978 dollars. The installed capital cost and cost of electricity numbers as described here are in beginning of year 1984 dollars.

2.1 BASIC ASSUMPTIONS FOR SRE METHOD

The basic assumptions as used in the SRE method are listed below.

2.1.1 Direct Cost

Following are the assumptions used in direct cost.

- Plant location is in an area of the country where minimal depth of foundations are required for frost protection.
- Topography of the land is relatively flat, resulting in a minimal amount of earthwork.
- Site is located 5 miles from existing railway mainline and major highway.
- Painting cost is 0.35% of total plant cost (based on Stearns-Roger historical records).
- Instrumentation will be higher than normally experienced on a coal fired power plant. Instrumentation estimated at 2.7% of total plant cost (normally 1.5 to 2.5%).
- Labor rates are the national average for 126 cities, with composite rate averaging $14.00 per hour.
- Pipe lengths, fittings and sizes, where not detailed on the conceptual drawings, are based on historical averages on similar size installations and on assumed pipe routings.

2.1.2 Indirect Cost

The indirect costs used in this method were derived from SRE historical data as follows.

- Indirect cost are 76% of the direct labor cost.
- A/E engineering and fee is 6.0% of the total field cost.
- Sales tax assumed as 4.0% of all material and equipment items.
- Contingency of 12.5% is used. This is developed from using 10% on all balance of plant items as well as many of the component items. On equipment with high developmental risk, a contingency of 20 to 25% is used resulting in an overall composite of 12.5% contingency factor.
- Contractor's fee or profit of 5.0% is added.
- Escalation of 6.5% annually is applied monthly for the construction period.
- Interest during construction is assumed as 8.0% annually compounded monthly.

2.1.3 O&M Cost

Operating and maintenance cost for the CFCC conceptual commercial plant are developed for estimating the cost of electricity (see Section 2.6). Labor, material and supplies are derived from historical and current data. Basic elements for the derivation of the O&M cost are:

- The number of personnel for the CFCC plant will be higher than normally encountered on a conventional coal fired power plant of this size due to the additional equipment associated with this plant. It is estimated that 125 people are required.
- Average composite wage rate - $9.95/hr.
- Assume 2080 hours/year/man.
- Assume 5% overtime (based on historical records).
- Assume cost of equipment, materials and supplied are 78% of the total labor cost (based on historical records).

2.2 BASIC ASSUMPTIONS FOR GE ECAS METHOD

The basic assumptions used with this method are as listed below.

2.2.1 Direct Cost

The assumptions used in direct cost are the same as used by SRE and given in Section 2.1.1.

2.2.2 Indirect Cost

In this method, it is assumed that:

- All indirect field labor cost are 90% of direct field labor cost.
- A/E engineering fee is 15% of sum of balance of plant (BOP) labor, material and indirect costs.
- Contingency is 20% of total plant cost.
- Escalation during construction is 6.5%/year compounded monthly.
- Interest during construction @ 10%/year compounded monthly.

2.2.3 O&M Cost

The assumptions used in O&M cost are the same as used by SRE and given in Section 2.1.3.

2.3 BASIC ASSUMPTIONS FOR GE - I&SEBD METHOD

The basic assumptions used in this method are as given below.

2.3.1 Direct Cost

The assumptions used in direct cost are the same as given in Section 2.1.1 except instrumentation cost. In this method instrumentation and controls costs are calculated based on the actual controls subsystem description.

2.3.2 Indirect Cost

In this method, it is assumed that:

- All indirect cost are 30% of sum of direct field labor and direct materials. The breakdown of this 30% consists of 15% for construction facilities, 10% for A/E engineering services and 5% as contractor's fee and initial plant startup fee.
- Contingency is 20% of sum of direct field labor and materials cost.
- Escalation during construction is 6.5%/year compounded monthly.
- Interest during construction is @ 10%/year compounded monthly.

2.3.3 O&M Cost

The assumptions used in O&M cost in this method are the same as given in Section 2.1.3.

2.4 MAJOR COMPONENT COST

The cost of all major components were provided by GE for the three estimating activities. These data were developed as part of the commercial plant design activity and provided a common point of initiation. The reference plant as costed includes the major features as identified below. Note that the potential cost and/or performance benefits indicated have not been included. Clearly, the evolving technology development program will provide components which will ultimately impact the costs reported here.

Subsystem	Reference Configuration For Cost Estimating	Cost Improvement Variations
Combustor Steam Generator	2 combined beds per module, horizontal pressure vessel	2 bed, horizontal vessel
	Waterwall configuration 1750°, 4.5 fps, 20% excess air	Refractory Walls
	No above bed surfaces	Above bed tubes for particulate and alkali control
	Supercritical	Subcritical
Gas Turbine	MS7001B	MS7001E - higher flow
	25000 hour life	Shorter cycle re-bucket vs. cost of protection
	Internal air cooling, clad	water cooling, coatings
Coal/Dolomite Feed	Petrocarb	
	Separate coal/sorbent feed	Mixed feedstock
Hot Gas Cleanup	Conventional/electro-cyclone	Configuration optimization based on process development testing

2.5 INSTALLED CAPITAL COST SUMMARIES

The installed capital cost summaries of the CFCC conceptual commercial plant has been prepared in four code of accounts as given below:

- ECAS Code of Accounts using GE ECAS assumptions
- SRE Code of Accounts using SRE assumptions
- Federal Code of Accounts using GE-I&SEBD assumptions
- CFCC commercial plant subsystem Code of Accounts using GE-I&SEBD assumptions

The above first two cost summaries are prepared by Stearns-Roger Engineering with their own independent estimates of direct materials and labor. The remaining two cost summaries are prepared by the Installation and Service Engineering Business Division of General Electric using its technique in estimating direct materials and labor. The major component cost, direct materials and labor cost are in year mid 1978 dollars. The assumed period of construction is 5 1/2 years. The final installed capital cost numbers including escalation and interest during construction are in year beginning 1984 dollars.

2.5.1 ECAS Code of Accounts Using GE ECAS Assumptions

Seven major categories are used in the ECAS capital cost analysis. Using a composite labor rate of $14.00 per hour, the data is summarized in Table 1. Indirect field labor is applied at 90% of the direct labor. The A/E home office costs and fee of 15% is applied to balance of plant items only (total excluding component cost), and a contingency of 20% applied to all items. The total plant capital cost is $435.1 million dollars. The value of escalation and interest during the 5.5 year construction period is added to this capital cost. This value is 54.8% of the total plant capital cost. The result is a final installed capital cost of $673.5 million dollars. The plant output is 658.3 MW_e net. The plant installed $/KW in year beginning 1984 dollars is $1023.1/KW.

2.5.2 SRE Code of Accounts Using SRE Assumptions

The SRE Code of Accounts for cost estimating is based on a breakdown of items are by construction category (earth-work, concrete, electrical, etc.) rather than by systems. The same basic work sheets used for the ECAS system were utilized in the SRE code of accounts, and only the method of accumulation varies.

Table 2 represents the estimate summary. Composite labor rate of $14.00 per hour is used as an average. Indirect field labor in the amount of 76% of the direct labor is added. In addition, engineering cost of 6%, sales tax of 4% of material, contingencies of 12.5%, a contractor's fee of 5% and escalation and interest during 5.5 years construction at the rate of 6.5% and 8% compound interest is added to

TABLE 1

ECAS CODE OF ACCOUNTS USING GE
ECAS ASSUMPTIONS

COST (MILLIONS OF DOLLARS)

Categories	Components	1.Direct Labor*	2.Indirect Labor**	3.Materials	Total
1.0 PFB Steam Generators	34.6	14.3	12.8	3.0	64.7
2.0 Turbine Generators	60.1	2.0	1.8	0.9	64.8
3.0 Process Mechanical Equipment	57.3	23.0	20.7	0.8	101.8
4.0 Electrical	17.7	6.4	5.8	0.8	30.7
5.0 Civil and Structural	---	4.6	4.1	7.2	15.9
6.0 Process Piping and Instrumentation	---	14.5	13.0	23.9	51.4
7.0 Yardwork and Miscellaneous***	---	2.4	2.1	3.6	8.1
SUBTOTALS	169.7	67.2	60.3	40.2	337.4

B.O.P. LABOR, MATERIALS & INDIRECTS (SUM OF 1 + 2 + 3)	= 167.7
A/E HOME OFFICE & FEE @ 15% (OF SUM OF 1, 2, & 3)	= 25.2
TOTAL PLANT COST	= 362.6
CONTINGENCY @ 20% OF TOTAL PLANT COST	= 72.5
TOTAL CAPITAL COST	= 435.1
ESCALATION & INTEREST DURING CONSTRUCTION ****	= 238.4
TOTAL INSTALLED CAPITAL COST	= 673.5

* COMPOSITE MAN-HOUR RATE ASSUMED AS $14.00/HR.
** INDIRECT LABOR (2) CALCULATED @ 90% OF DIRECT LABOR (1)
*** COST OF LAND NOT INCLUDED
**** CALCULATED AS 54.8% OF TOTAL CAPITAL COST

NOTE: All costs on this page are expressed in mid year 1978 dollars, excluding adders on escalation & interest dur- contruction. Total installed capital cost is in year beginning 1984 dollars.

TABLE 2

SRE-CODE OF ACCOUNTS USING
SRE ASSUMPTIONS
COST (MILLIONS OF DOLLARS)

Category	1. Direct Labor*	2. Indirect Labor **	3. Components and Materials	Total
A. Earthwork	1.3	1.0	0.7	3.0
B. Concrete	1.8	1.4	2.2	5.4
C. Building & Structure	1.8	1.4	4.3	7.5
D. Process Equipment	40.3	30.6	154.7	225.6
E. Piping	10.7	9.6	18.7	39.0
F. Electrical	6.4	4.9	17.6	28.9
G. Painting	1.2	0.9	0.3	2.4
L. Plant Items	1.1	0.8	2.3	4.2
N. Instrumentation & Control	3.0	2.3	9.0	14.3
P. Insulation	0.6	0.4	0.7	1.7
	68.2	53.3	210.5	332.0

Engineering @ 6% of (sum of 1+2+3)	19.9
Sales Tax @ 4% of 3	8.4
Total Plant Cost	360.3
Contingency @ 12.5% of Total Plant Cost	45.0
Subtotal	405.3
Fee @ 5% of Subtotal	20.3
Total Capital Cost	425.6
Escalation and Interest***	209.2
Total Installed Capital Cost	634.8

* Composite Man-hour Rate Assuemd as $14.00/Hr

** Indirect Labor (2) @ 76% Direct Labor (1)

*** 6.5% Escalation, 8% Compound Interest for 5½ Yrs

NOTE: All costs on this page are expressed in mid year 1978 dollars excluding adders on escalation & interest during construction. Total installed capital cost is in year beginning 1984 dollars.

to yield a total installed capital cost of $634.8 million dollars. The plant installed $/KW in year beginning 1984 dollars is $964.3/KW.

2.5.3 Federal Code of Accounts Using GE I&SEBD Assumptions

The CFCC plant capital cost estimate summary in Federal Code of Accounts using the GE I&SEBD assumptions is shown in Table 3. Total indirect costs are 30% of direct costs and the contingency cost is 20% of total direct and indirect costs. Period of construction is 5.5 years. Escalation is at the rate of 6.5% per year and interest during construction is 10%/year compounded monthly. The installed capital cost of the CFCC plant is $608.9 million dollars and the plant installed $/KW in year beginning 1984 dollars is $925/KW.

2.5.4 Commercial Plant Subsystem Code of Accounts Using GE-I&SEBD Assumptions

The installed plant capital cost number by this method of accounting system is the same as using the Federal Code of Accounts System. It is because the assumptions used are the same. Only the Code of Accounts are different. The Code of Accounts are in accordance with the commercial plant subsystem designations as delineated in Reference 4. The Commercial Plant Capital Cost Estimate Summary is given in Table 4. The $0.5M differences between Tables 3 and 4 can be attributed to rounding. The percentage numbers for indirects, contingency, escalation and interest during construction are the same as described in Section 2.5.3.

2.6 COST OF ELECTRICITY SUMMARIES

This subsection describes the cost of electricity (CoE) numbers on year beginning 1984 basis with an 80% capacity factors using the 3 costing procedures (the SRE method, GE ECAS method, and GE I&SEBD method). These numbers are shown in Table 5. The results indicate that the CoE is in the range of 38.0 to 40.5 mills/KW-HR.

TABLE 3

CAPITAL COST ESTIMATE SUMMARY IN
FEDERAL CODE OF ACCOUNTS USING GE I&SE ASSUMPTIONS

ACCOUNT NUMBER	DESCRIPTION	TOTAL COST IN MILLIONS OF DOLLARS			
		EQUIPMENT	MATERIALS	LABOR	TOTAL
310	Land and Land Rights	0	0	0	0
311	Structures & Improvements	0	7.6	4.9	12.5
312	Combustor/Steam Generation Equipment	86.0	7.8	29.2	123.0
313	Gas Turbine Generator System	31.0	4.7	2.0	37.7
314	Steam Turbine Generator System	40.6	7.2	10.1	57.9
315	Electric Plant Equipment	2.9	5.2	9.0	17.1
316	Miscellaneous Power Plant Equipment	.9	1.0	.7	2.6
317	Instrumentation & Control System	5.2	1.2	1.5	7.9
350	Transmission Plant	3.0	.1	.4	3.5
	Total Direct Costs	169.6	34.8	57.8	262.2
900	Indirect Costs				
910	Construction Facilities 15% Direct				39.3
920	Engineering Services 10% Direct				26.2
930	Other Costs 5% Direct				13.1
940	Contingency 20% Direct				52.5
950	Escalation & Interest During Construction				215.6
960	Installed Capital Cost				608.9

NOTE: All costs on this page are expressed in mid year 1978 dollars excluding adders on escalation & interest during construction. Total installed capital cost is in year beginning 1984 dollars.

TABLE 4

CAPITAL COST ESTIMATE SUMMARY IN CFCC COMMERCIAL PLANT

SUBSYSTEM CODE OF ACCOUNTS USING GE I&SE ASSUMPTIONS

ACCOUNT NUMBER	DESCRIPTION	TOTAL COST IN MILLIONS OF DOLLARS			
		EQUIPMENT	MATERIALS	LABOR	TOTAL
10	Combustor Steam Generator Subsystem	19.4	2.4	8.0	29.8
20	Coal/Dolomite Feed Subsystem	16.3	.9	4.0	21.2
30	Hot Gas Cleanup Subsystem	11.7	1.3	2.9	15.9
40	Hot Gas Ducting Subsystem	11.4	.3	3.3	15.0
50	Waste Solids Processing Subsystem	19.5	.5	8.1	28.1
60	Gas Turbine-Generator & Auxilaries Subsystem	31.0	4.7	2.0	37.7
70	Steam Turbine-Generator & Auxiliaries Subsystem	29.2	1.1	3.6	33.9
80	Master Control/Instrumentation Subsystem	5.2	1.2	1.5	7.9
90	Balance-of-Plant Subsystem	25.9	22.5	24.6	73.0
	TOTAL DIRECT COSTS	169.6	34.9	58.0	262.5
900	Indirect Costs				
910	Construction Facilities 15% Direct				39.4
920	Engineering Services 10% Direct				26.3
930	Other Costs 5% Direct				13.1
940	Contingency 20% Direct				52.5
950	Escalation & Interest During Construction				215.6
960	Installed Capital Cost				609.4

NOTE: All costs on this page are expressed in mid-year 1978 dollars excluding adders on Escalation & Interest during construction. Total installed capital cost is in year beginning 1984 dollars.

TABLE 5

COST OF ELECTRICITY SUMMARIES FOR CFCC PLANT
YEAR 1984 BASIS AND 80% CAPACITY FACTOR

Net Plant Heat Rate = 8446.2 Btu/KW-Hr.

Net Output = 658.3 MW_e

Description	Capital Investment $\$ \times 10^6$	Plant Installed Cost in $/KW	KW-Hrs/Year x 10^6	Annual Fixed Charges $\$ \times 10^6$	Fuel Cost $\$ \times 10^6$	Dolomite Cost $\$ \times 10^6$	1st Year O&M Cost $\$ \times 10^6$	Annual Plant Cost (Total) $\$ \times 10^6$	Mills/KW-Hr (1st Year)
ECAS Method	673.5	1023.1	4.614	121.2	46.2	12.8	6.8	187.0	40.5
SRE Method	634.8	964.3	4.614	114.3	46.2	12.8	6.8	180.1	39.0
GE-I&SE Method	608.9	925.0	4.614	109.6	46.2	12.8	6.8	175.4	38.0

NOTE: The original ECAS PFB Plant cost of electricity escalated to the 1984 basis is 37.2 mills/KW HR for 658.3 MW_e Plant.

NOTE: Costs on this page are expressed in year beginning 1984 dollars.

The basic parameters used in the current CFCC study for computing cost of electricity are as follows:

Steam Turbine Generation Gross MWE	=	524.5
Gas Turbine Generation Gross MWE	=	154.2
Plant Generation Net MWe	=	658.3
Fixed Financing Charges, %	=	18
Minimum Acceptable Return (MAR), %	=	11
Escalation Rate, %/Year	=	6.5
Plant Life, Years	=	30
Construction Start	=	August, 1978
Commercial Operation	=	February, 1984
Coal, Higher Heating Value (HHV) Btu/Lb.	=	10,788
Coal Cost in Year Mid 1978 $/Ton	=	18.12
Coal Cost in Year Mid 1978 $\$/10^6$ Btu	=	0.84
Dolomite Cost in Year Mid 1978 $/Ton	=	15
Coal Consumption in Tons/Hr.	=	257.7
Dolomite Consumption in Tons/Hr.	=	86.7
Plant Installed Capital Cost:		
ECAS Method, $\$ \times 10^6$	=	673.5
SRE Method, $\$ \times 10^6$	=	634.8
GE-I&SE Method, $\$ \times 10^6$	=	608.9

ECAS Method includes: 6 1/2% escalation, 10% interest during construction (compounded monthly).

SRE Method includes: 6 1/2% escalation, 8% interest during construction (compounded monthly).

GE-I&SE Method includes: 6 1/2% escalation, 10% interest during construction (compounded monthly).

O&M cost was developed by utilizing Stearns-Roger historical records, experience and basic assumptions as presented in Section 2.1.3 of this report.

2.7 COMPARISON OF ESTIMATING TECHNIQUES

Through the development of three independent cost estimates, it is possible to assess the degree of precision associated with the cost estimating process. All cost estimates of the CFCC plant were initiated with a common list of major components and vendor quotes for these components. Each cost analysis

- Estimated direct labor and material.
- Applied indirects, A&E, tax, fee, contingency, etc., using their developed techniques.
- Added escalation and interest for the 5 1/2 year construction period.

Tables 5 and 6 present a comparison of the three estimates.

- The capital cost estimates vary from 925 $/KW to 1023 $/KW (1984 basis), providing a ten percent spread in the estimates.
- The COE electricity estimates, in spite of using a common fuel, dolomite and O&M cost, vary by 6% from one to the other. Adding variability due to feedstock and O&M costs would raise this imprecision to about 10%.

Hence, the precision of the cost estimating process, starting from a common design with common hardware costs can be assessed as ±10% due simply to the cost estimating technique applied.

TABLE 6

CFCC PLANT INSTALLED COST COMPARISON

DESCRIPTION	ECAS	SRE	GE I&SE
Total Estimated Direct Cost, $ x 10^6	277.7	278.7	262.2
Indirect, $ x 10^6:			
@ 90% Direct Labor	60.4	--	--
@ 76% Direct Labor	--	53.3	--
@ 20% Total Direct Labor	--	--	52.5
A/E Engineering & Fee, $ x 10^6			
@ 15% of Labor, Materials & Indirects	25.2	--	--
@ 6% of Direct plus Indirects	--	19.9	--
@ 10% of Direct Costs	--	--	26.2
Contractor's Fee, $ x 10^6; @ 5%	--	20.3	--
Sales Tax, $ x 10^6; @ 4%	--	8.4	--
Contingencies, $ x 10^6			
@ 20% of Total Plant Cost	72.5	--	
@ 12.5% of Total Plant Cost	--	45.0	--
@ 20% of Direct Costs	--	--	52.4
Total Estimated Capital Cost, Year Mid 1978, $ x 10^6	435.1	425.6	393.3
Escalation & Interest During 5.5 Years of Construction, $ x 10^6:			
@54.8% of Above Total	238.4	--	215.6
@ 6.5% & 8% Compound Interest	--	209.2	--
Total Plant Installed Cost, Year Beginning 1984, $ x 10^6	673.5	634.8	608.9
Plant Installed Cost $/KW Year Beginning 1984	1,023.1	964.3	925.0

NOTE: All costs on this page are expressed in mid year 1978 dollars excluding adders on escalation & interest during construction. Total installed capital cost is in year beginning 1984 dollars.

SECTION III

CONVENTIONAL STEAM PLANT COST ESTIMATES

This section describes published cost data for conventional steam plants. For conventional steam plants, use has been made of the EPRI Technical Assessment Guide (TAG) Reference 1, and GE ECAS study for conventional plants, Reference 2, and Burns & Roe Study for pulverized coal fired plant with flue gas desulfurization system, Reference 7.

3.1 EPRI COAL FIRED CONVENTIONAL STEAM PLANT

Regional data for coal fired conventional steam plant as reported in Reference 1 is given in Table 7. Note that costs in this study are reported in 1976 dollars so that direct comparison with prior data requires an escalation of 6.5% per year. The capital cost data is based on a study by the Bechtel Corporation, Reference 5. A power plant design for each region was developed with variations made to adapt the plant design and costs to the plant site selected and the particular coal which would be burned in each given region. The upper value of the range of capital costs for the West Region has been increased to account for additional construction costs which would result from building a power plant having increased environmental design requirements. The gas scrubber cost for 1.2#/10^6 BTU emissions is in the range of \$82/KW to \$145/KW in 1976 dollars.

In the EPRI study, two equal size units, each 1000 MW net have been selected as the reference design. If only one unit was built the cost per KW for the plant and the flue gas desulfurization would increase by 1/0.92. For a unit which is different from 1000 MW in size, the cost per KW can be calculated by $C=C_o(MW_o/MW)^{0.15}$ where C and C_o are the new and original cost per KW respectively and MW, MW_o are the new and 1000 MW unit size respectively. The exponential factors apply only to units between 500 and 1000 MW in size. The cost per KW of a 500 MW unit is estimated to be 1.11 times the cost per KW of a 1000 MW unit. A restatement of the conventional plant cost of 1984 dollars, including adjustment to 658 MW_e is shown in Table 8.

3.2 GE ECAS COAL FIRED CONVENTIONAL STEAM PLANT

A study, Reference 2, was performed on a basis consistent with the General Electric ECAS Phase II, Reference 3, on evaluation of advanced energy conversion systems for electric utility base load applications using coal or coal derived fuels. This study was performed to estimate the technical/economic characteristics of a steam power plant (3500 Psig, 1000°F/1000°F) with a coal burning radiant furnace and a wet lime stack gas scrubber to control sulfur emissions. Particulate emissions were controlled by an electrostatic precipitator operating at 300°F. The stack from the scrubber was reheated from

TABLE 7

REGIONAL COAL POWER PLANT CHARACTERISTICS[1]
Costs in 1976 Dollars

Region	Capitalized[2] Plant Cost (Includes FGD) $/kW	FGD $/kW	Operations & Maintenance Fixed $/kW/yr	Operations & Maintenance Variable Mills/kWh	Average Heat Rate Btu/kWh	Design Sulfur Removal %	Lime Cost Mills/kWh
Northeast	696 638-759	133 122-145	2.52	1.48	9834	82	.41
Southeast	567 519-619	108 99-118	2.05	1.30	9878	82	.48
East Central	661 605-721	128 117-140	2.39	1.43	9934	87	.71
West Central	652 597-711	89 82-98	2.36	1.42	10102	52	.02[3]
South Central	647[4] 593-706	126 116-138	2.34	1.41[5]	10445	82	.48
West	675 618-810	92 85-111	2.44	1.45	10102	52	.02[3]

(1) Based on NSPS standard.

(2) The most likely range and the expected value of capital costs are shown. The high value of the range of capital costs for the West region included added environmental considerations in plant design.

(3) 0.6% sulfur burned 25% per year with 0.5% sulfur average for year.

(4) An additional $62/kW should be added to these values to account for the additional transmission associated with this minemouth power station.

(5) An additional $.25/MWh should be added to account for additional transmission energy losses.

NOTE: Costs on this page are expressed in year 1976 dollars.

TABLE 8

EPRI TECHNICAL ASSESSMENT GUIDE
REGIONAL COAL POWER PLANT COSTS
AT 658 MW_e IN 1984

	Capitalized Plant Cost Based Upon Two 1000 MW_e Units In 1976 Dollars $/KW	Capitalized Plant Cost Based Upon One 658 MW_e Units In 1984 Dollars $/KW
Northeast	696	1333
Southeast	567	1086
East Central	661	1266
West Central	652	1249
South Central	647	1239
West	675	1293

Note: Costs on this page are expressed in Year 1976 or 1984 dollars as shown.

125°F to 250°F as a base case and from 125°F to 175°F as an alternate case. A conceptual design of the power plant was developed, including the on-site calcination of limestone to lime and the provision of sludge ponds to store the products of flue gas scrubbing. From this design, estimates were derived for power plant efficiency, capital cost and cost of electricity at an assumed capacity factor of 65%. The plant capital cost estimate summary of the base case (250°F stack temperature) and the alternate case (175°F stack temperature) is shown in Table 9. Further, the methodology of the above evaluation was also applied to a plant in which low sulfur coal would be burned and the wet gas scrubbing system dispensed with. Table 10 compares the performance and cost of the plant with no scrubbers and 250°F stack gas temperature with the above wet scrubber cases. Note the gas scrubber cost differential for 175°F wet scrubber is $151/KW and for 250°F wet scrubber is $215/KW (in 1981 dollars).

3.3 BURNS & ROE PULVERIZED COAL FIRED (PCF) PLANT WITH FUEL GAS DESULFURIZATION (FGD) SYSTEM

The Burns & Roe reference PCF plant thermal cycle, Reference 7, has seven feed water heaters and turbine throttle steam conditions of 2400 psig and 1000°F, and reheat to 1000°F. The plant consists of two units, each with a turbine generator guaranteed for a 568,214 KW gross output at 2.4 inches Hg back pressure. The maximum capability of this turbine generator is 620, 180 KW with valves wide open and 5% overpressure at the throttle. The turbine is a tandem compound four flow machine with 30 inches last stage blade length and a speed of 3600 rpm.

The plant site encompasses approximately 440 acres with a river running along its eastern border, with a diked area of 55 acres utilized for scrubber sludge and ash pond. An additional diked area of 10 acres is used for drain water hold up pond. The plant includes a barge unloading facility, coal handling equipment and limestone handling equipment. The steam generator is a subcritical forced circulation type, dry bottom ash boiler having a furnace volume, water walls, evaporator, convection pass, steam drum, downcomers, circulation pumps, economizer, casing, insulation, support structure, controls and instrumentation. A limestone slurry process as shown in Figure 1 is used in this plant for desulfurization of flue gas with fly ash removal provided by electrostatic precipitator.

The environmental standards for the plant design corresponds to the June 1979 New Source Performance Standards.

	Emission Limits (lbs/10^6 BTU)
SO_2	(90% removal for eastern bituminous 70% removal for western subbituminous)
NO_x as NO_2	(0.6 for eastern bituminous 0.5 for western subbituminous)
Total Particulates	0.03

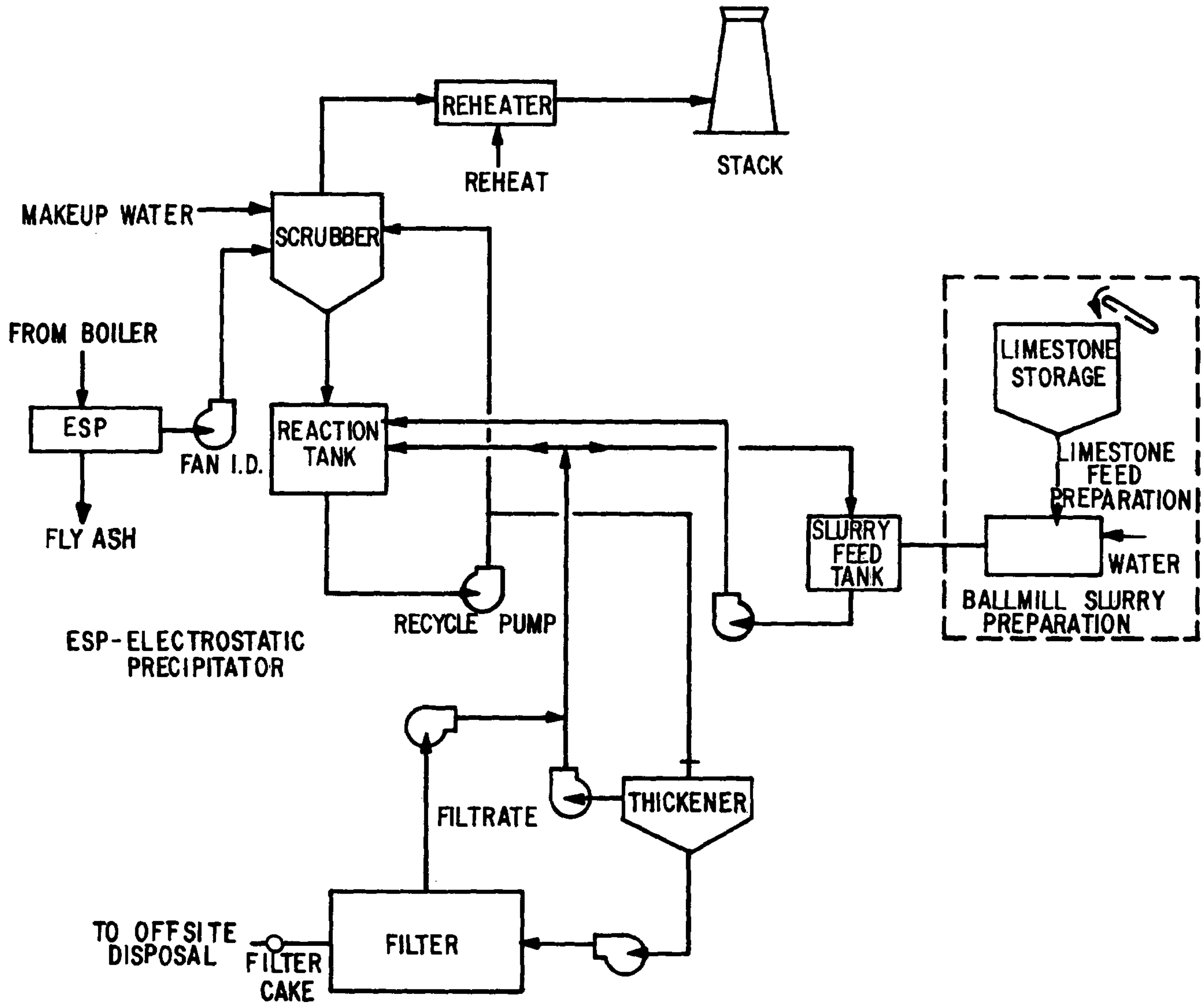

FIGURE-1 FGD LIMESTONE SLURRY PROCESS DIAGRAM

TABLE 9

PLANT CAPITAL COST ESTIMATE SUMMARY
CONVENTIONAL STEAM PLANT — WET SCRUBBERS — 250 F Stack
(Approximate Distribution)
COSTS (Millions of Dollars)

		MAJOR COMPONENTS M$	BOP MATERIALS M$	SITE LABOR (DIRECT & INDIRECT) M$	TOTAL M$
1.0	LAND IMPROVEMENTS & STRUCTURES (LAND, PLANT AREA 92 ACRES) (LAND, 30-YEAR DISPOSAL 1785 ACRES)	0	16.8	26.5	43.4
2.0	COAL HANDLING	0	9.2	2.7	11.9
3.0	PRIME CYCLE PLANT EQUIPMENT	71.9	60.9	67.2	199.9
4.0	BOTTOM CYCLE NOT APPLICABLE				
5.0	ELECTRICAL PLANT & INSTRUMENTATION	0	17.8	28.6	46.4
	SUBTOTAL	71.9	104.7	125.0	301.6
6.0	A-E SERVICE & CONTINGENCY				101.7
7.0	ESCALATION & INTEREST DURING CONSTRUCTION				221.0
				TOTAL M$	624.3
				PLANT OUTPUT MW	747.2
				TOTAL $/kW	835.4

PLANT CAPITAL COST ESTIMATE SUMMARY
CONVENTIONAL STEAM PLANT — WET SCRUBBERS — 175 F STACK
(Approximate Distribution)
COSTS (Millions of Dollars)

		MAJOR COMPONENTS M$	BOP MATERIALS M$	SITE LABOR (DIRECT & INDIRECT) M$	TOTAL M$
1.0	LAND IMPROVEMENTS & STRUCTURES (LAND, PLANT AREA 92 ACRES) (LAND, 30-YEAR DISPOSAL 1785 ACRES)	0	16.8	26.5	43.4
2.0	COAL HANDLING	0	9.2	2.7	11.9
3.0	PRIME CYCLE PLANT EQUIPMENT STEAM CYCLE/CF 868.2 MW_e	72.6	57.6	64.7	194.8
4.0	BOTTOM CYCLE NOT APPLICABLE				
5.0	ELECTRICAL PLANT & INSTRUMENTATION	0	17.7	28.6	46.3
	SUBTOTAL	72.6	101.3	122.5	296.4
6.0	A-E SERVICE & CONTINGENCY				99.6
7.0	ESCALATION & INTEREST DURING CONSTRUCTION				217.5
				TOTAL M$	613.6
				PLANT OUTPUT MW_e	795.5
				TOTAL $/k$W_e$	771.3

NOTE: All costs on this page are expressed in mid year 1975 dollars excluding adders on escalation & interest during construction. Total installed capital cost is in year beginning 1981 dollars.

A summary of capital cost and plant auxiliary power requirements for the above nominal 1000 MWe eastern and western plants are presented in Tables 11 and 12.

Assuming a plant life of 30 years and the plant construction period of 4 years, the economic analyses results for eastern and western coal fired PCF power plants with limestone beds are presented in Table 13.

The specific capital cost and levelized cost for the eastern and western coal fired base plants, each generating a total of 1136.43 MWe and operating in compliance with the applicable NSPS emission requirements, were determined to be $734 and $706 net, respectively and 50.35 and 45.10 mills/KWh, respectively.

A breakdown of the categories developed for determination of the PCF power generating costs is presented in the following paragraphs.

The total capital requirement (TCR) indicated in Table 13 includes all the capital investment required to complete the project. This requirement is presented in Table 14 and is comprised of:

- Total Plant Investment
- Royalty Allowance
- Preproduction Costs
- Inventory Capital
- Initial Catalyst and Chemicals Charge
- Allowance for Funds during Construction
- Land

Royalty allowance is assumed to be paid by the equipment manufacturers and is included in the equipment cost.

Preproduction costs are presented in Table 15, 16, 17 and 18.

The value of inventories of fuel, other consumables, and by-products is capitalized and included in the inventory capital account. The inventory capital is presented in Table 19 and is estimated as follows:

- One month's supply of fuel based on full capacity operation
- One month's supply of other consumables (excluding water) based on full capacity operation.

All chemical costs are included in the inventory capital.

Allowance for Funds During Construction (AFDC) is calculated from the center of gravity of expenditures, based on compounding 8% per year interest over the plant construction expenditures schedule. For a center of gravity of 2 years, corresponding to a 4 year construction period before completion, the AFDC is 16.6% of Total Plant Investment (TPI). Table 20 given below presents the AFDC for PCF plants.

TABLE 10

SYSTEM OUTPUT
CONVENTIONAL STEAM PLANTS

Parameter	250°F Wet Scrubbers	175°F Wet Scrubbers	250°F No Scrubbers
Generator Output, MW	819.9	868.6	883.9
Auxiliary Losses, MW	72.7	73.1	59.2
Net Plant Output, MW	747.2	795.5	824.7
Output Ratio	0.94	1	1.04
Overall Energy Efficiency, %	31.8	33.8	36.2
Capital Cost, M$	624	614	511
Capital Cost, $/kW	835	771	620
Electricity Cost, mils /kWh			
Capital	26.4	24.4	
Fuel	10.7	10.1	
O&M	2.6	2.5	
Total	39.7	37.0	

NOTE: All costs on this page are expressed in year beginning 1981 dollars.

TABLE 11

CAPITAL COSTS FOR
PCF PLANTS

FPC Acct. No.	Description of Account	Eastern	Western
310.0	LAND - TOTAL	$ 2,700,000	$ 2,200,000
311.1	Yard Work	12,595,000	12,190,000
311.2	Boiler House	21,821,000	21,900,000
311.3	T.G. Building	9,103,000	9,135,000
311.4	Service Building	1,527,000	1,527,000
311.5	Water Treatment Building	100,000	100,000
311.6	Waste Treatment Building	(Included in	Account 311.5)
311.7	Make-Up Water Intake Structure	401,000	401,000
311.8	Barge Unloading Facility	1,058,000	1,058,000
311.9	TOTAL ACCOUNT	46,605,000	46,311,000
312.1	Steam Generating Equipment (Including FGD System)		
312.2	Draft System	214,128,000	200,486,000
312.5	Instrumentation		
312.3	Coal and Limestone Handling	23,885,000	23,975,000
312.4	Ash and Dust Handling	8,560,000	9,010,000
312.6	Steam and Feedwater System	33,500,000	33,500,000
312.7	Water Treatment System	2,740,000	2,740,000
312.8	Miscellaneous	1,886,000	1,886,000
312.0	TOTAL ACCOUNT	284,699,000	271,597,000
314.1	T.G. and Accessory Equipment	56,784,000	56,784,000
314.2	Circulation Water System	22,564,000	22,564,000
314.3	Condensing System	14,502,000	14,502,000
314.4	T.G. Auxiliaries	5,130,000	5,130,000
314.5	Instrumentation	9,500,000	9,500,000
314.0	TOTAL ACCOUNT	108,480,000	108,480,000
315.1	Switchgear	5,430,000	5,430,000
315.2	Station Service Equipment	6,264,000	6,264,000
315.3	Switchboards	506,000	506,000
315.4	Protective Equipment	694,000	694,000
315.5	Elec. Struct. and Wiring Containers	6,422,000	6,422,000
315.6	Power and Control Wiring	13,174,000	13,174,000
315.0	TOTAL ACCOUNT	32,490,000	32,490,000
316.1	Air and Water Service System	2,464,000	2,464,000
316.2	Communication Equipment	492,000	492,000
316.3	Furnishing and Fixtures	778,000	778,000
316.0	TOTAL ACCOUNT	3,734,000	3,734,000
353.0	STATION EQUIPMENT TOTAL	5,742,000	5,742,000
	TOTAL DIRECT CONSTRUCTION	$481,750,000	$468,354,000

Note: Costs are based on mid-1978 dollars for a 1136 MWe gross output power plant located in a mid-continental U.S. area.

Table is extracted from Reference 7.

TABLE 12

AUXILIARY POWER REQUIREMENTS
FOR 1000 MWe
EASTERN AND WESTERN PCF PLANTS

System	Power, kW	
	Eastern	Western
BOILER PLANT		
Coal Mills	3,000	3,880
Primary Air Fans	2,426	3,140
Forced Draft Fans	2,906	2,936
Induced Draft Fans	5,028	5,128
Boiler Circulation Pumps	3,940	3,940
Fuel Feed	806	816
Precipitators	3,400	3,400
Miscellaneous Equipment	246	246
Boiler Plant Total	21,752	23,486
Turbogenerator Building Total	5,440	5,440
FGD System	17,332	10,512
Balance of Plant Total	19,836	19,832
Total	64,360	59,270

This Table is extracted from Reference 7.

TABLE 13

CAPITAL INVESTMENT AND
REVENUE REQUIREMENTS FOR PCF PLANTS

PARAMETER	EASTERN	WESTERN
Criteria		
SO_2 Emission Std.	90%	70%
Ca/S, mole ratio	1.02	1.3
Operating Conditions		
Gross Power Output, MW	1136.43	1136.43
Auxiliary Power, MW	64.36	59.27
Net Power Output, MW	1072.07	1077.16
Boiler Efficiency, %	88	85.3
Net Plant Heat Rate, Btu/kWh	9,741	9,694
Materials/Consumption/Production		
Coal Consumption, ton/h	517.0	651.0
Limestone Consumption, ton/h	66.6	10.93
Solid Wastes, wet, ton/h	86.43	14.28
Solid Wastes, dry, ton/h	82.92	41.64
Water Consumption, GPM	13,000	13,000
Capital Investment (mid-1978 dollars)		
Capital Cost, $ millions	787	760
Capital Cost, $/net kW	734	706
30-Yr Levelized Fixed Charges, $/kW-yr	132	127
30-Yr Levelized Costs (1979-2008)		
Limestone, mills/kWh	1.17	.19
Waste Disposal, mills/kWh	2.53	.83
Water, mills/kWh	.55	.55
Other Consumables, mills/kWh	.28	.28
Total Variable O&M, mills/kWh	4.54	1.85
Fixed O&M, mills/kWh	3.88	3.86
Fixed Charges, mills/kWh	21.53	20.71
Subtotal, mills/kWh	29.95	26.42
Fuel Cost, mills/kWh	20.40	18.68
Busbar Power Cost, mills/kWh	50.35	45.10

Results are based on plant located in mid-continental U.S. area burning eastern coal with a HHV of 10,100 Btu/lb and 4% sulfur and western coal with a HHV of 8,020 Btu/lb and 0.48% sulfur and a 70% capacity factor. All costs are based on mid-1978 dollars.

This Table is extracted from Reference 7.

TABLE 14

TOTAL CAPITAL REQUIREMENTS FOR
PCF PLANTS

Acct	Description	Eastern	Western
310	Land and Land Rights	$ 2,700,000	$ 2,200,000
311	Structures and Improvements	$ 46,605,000	$ 46,311,000
312	Boiler Plant Equipment	$284,699,000	$271,597,000
314	Turbogenerator Units	$108,480,000	$108,480,000
315	Accessory Electrical Equipment	$ 32,490,000	$ 32,490,000
316	Miscellaneous Power Plant Equipment	$ 3,734,000	$ 3,734,000
353	Station Equipment	$ 5,742,000	$ 5,742,000
	Total Direct Costs (Excluding Land)	$481,750,000	$468,354,000
	Undistributed Costs (6% Total Direct Costs)	$ 28,905,000	$ 28,101,000
	Process Capital	$510,655,000	$496,455,000
	General Facilities on Site (Costs included in Plant Fac)	$ 0	$ 0
	Engineering and Home Office Fees -- (10% of Direct Costs)	$ 48,175,000	$ 46,835,000
	Subtotal	$558,830,000	$543,290,000
	Project Contingency 15% of above subtotal	$ 83,825,000	$ 81,494,000
	Process Contingency	$ 6,190,000	$ 4,260,000
	Sales Tax	$ 0	$ 0
	Total Plant Investment (TPI)	$648,845,000	$629,044,000
	Royalty Allowance	$ 0	$ 0
	Preproduction Costs	$ 17,931,000	$ 16,211,000
	Inventory Capital	$ 9,328,000	$ 8,066,000
	Initial Catalyst and Chemicals Charge	$ 0	$ 0
	Allowance for Funds During Construction (16.6% of TPI)	$107,708,000	$104,421,000
	Land	$ 2,700,000	$ 2,200,000
	Total Capital Requirements	$786,512,000	$759,942,000
	Total Capital Required, $/kW net	734	706
	Net Plant Output, MWe	1072.07	1077.16

Note: Costs are based on mid-1978 dollars for a 1136 MWe PCF plant located in a mid-continental U.S. area. The eastern coal fired plant burns coal with a HHV of 10,000 Btu/lb and 4% sulfur. The western coal fired plant burns coal with a HHV of 8,020 Btu/lb and 0.48% sulfur.

This Table is extracted from Reference 7.

TABLE 15

PREPRODUCTION COSTS FOR A 1000 MWe EASTERN PCF PLANT

Item	Quantity	Unit Cost	Conversion Factor	Cost[1]
Operating Labor	$2,859,000/yr	See Note 2	1/12 yr	238,300
Maintenance Labor	$2,087,000/yr	See Note 2	1/12 yr	173,900
Administrative Labor	$1,483,800/yr	See Note 3	1/12 yr	123,700
Maintenance Material	$7,095,800/yr	See Note 4	1/12 yr	591,300
Waste Disposal	169.35 ton/h	$8.50/ton	730 h	1,050,800
Limestone	66.60 ton/h	$10.00/ ton	730 h	486,200
Water	13,000 gpm[5]	$0.40/ 1000 gal	730 h	227,800
Fuel	517.00 ton/h	$21.86/ ton	(25%)x730 h	2,062,500
2% of TPI				12,976,900
Preproduction Costs				$17,932,400

Note:
1. All costs are in mid-1978 dollars
2. Table 17 presents annual operating and maintenance labor
3. Administrative costs are 30% of O&M labor costs
4. Maintenance materials taken as 3.4 x maintenance labor
5. Table 18 presents annual water usage

This Table is extracted from Reference 7.

TABLE 16

PREPRODUCTION COSTS FOR A 1000 MWe WESTERN PCF PLANT

Item	Quantity	Unit Cost	Conversion Factor	Cost[1]
Operating Labor	$2,859,000/yr	See Note 2	1/12 yr	238,300
Maintenance Labor	$2,087,000/yr	See Note 2	1/12 yr	173,900
Administrative Labor	$1,483,800/yr	See Note 3	1/12 yr	123,700
Maintenance Material	$7,095,800/yr	See Note 4	1/12 yr	591,300
Waste Disposal	55.92 ton/h	$8.50/ton	730 h	347,000
Limestone	10.93 ton/h	$10.00/ton	730 h	79,800
Water	13,000 gpm[5]	$0.40/1000 gal	730 h	227,800
Fuel	651.0 ton/h	$15.56/ton	(25%)x730 h	1,848,600
2% of TPI				12,581,000
Preproduction Costs				$16,211,400

Note:
1. All costs are in mid-1978 dollars
2. Table 17 presents annual operating and maintenance labor
3. Administrative costs are 30% of O&M labor costs
4. Maintenance materials taken as 3.4 x maintenance labor
5. Table 18 presents annual water usage

This Table is extracted from Reference 7.

TABLE 17

ESTIMATE OF ANNUAL OPERATION AND MAINTENANCE LABOR COSTS FOR EASTERN AND WESTERN PCF PLANTS (Mid-1978 Dollars)

Classification	Annual* Salary Per Capita	No. of Person.	Annual Salary
Operation			
Operation Supervisor	36,000	1	36,000
Shift Supervisor	33,000	6	198,000
Control Room Operator	30,000	9	270,000
Asst. Control Room Operator	24,000	9	216,000
Turbine Operator	30,000	9	270,000
Aux. Equipment Operator	24,000	18	432,000
Boiler Operator	24,000	9	216,000
FGD Operator	22,000	15	330,000
Coal and Ash Crew	22,000	18	396,000
Computer Specialist	25,500	1	25,500
Environmental Specialist	25,500	1	25,500
Results Engineer	24,000	1	24,000
Assistant Results Engineer	20,500	6	123,000
Chemical Supervisor	33,000	1	33,000
Chemists	24,000	11	264,000
		115	2,859,000
Maintenance			
Maintenance Supervisor	36,000	1	36,000
Mechanical Maint. Foreman	31,000	1	31,000
Mechanic	24,000	19	456,000
Mechanic's Helper	19,000	19	361,000
Machinist	24,000	3	72,000
Welder	24,000	5	120,000
Carpenter	22,000	3	66,000
Bricklayer	19,000	1	19,000
Electr. Maint. Foreman	31,000	1	31,000
Electrician	24,000	9	216,000
Electrician's Helper	19,000	9	171,000
I & C Foreman	31,000	1	31,000
I & C Repairman	26,000	8	208,000
Building Maint. Foreman	22,000	1	22,000
Plumber	19,000	1	19,000
Laborers	12,000	19	228,000
		101	2,087,000
		216	4,946,000
Average Hourly Rates ($/HR)			
Operating			11.95
Maintenance			9.93
Total			11.01

*Annual salaries include both direct labor charges and payroll burden.

Notes: 1) Man-power estimates are based on a two unit 1136 MWe power generating plant.

2) $\text{Average Hourly Rate} = \dfrac{\text{Total Annual Cost (\$)}}{\text{Number of Person. x 2080 working hours/year}}$

This Table is extracted from Reference 7.

TABLE 18

WATER CONSUMPTION ANALYSIS
FOR 1000 MWe EASTERN AND WESTERN PCF PLANTS

	gpm	gpm/MWe gross
Cooling Tower		
Evaporative	9,400	8.27
Blowdown	1,000	.88
Draft	100	.09
Cooling Tower Total	10,500	9.24
Boiler Make-Up Water Treatment System	240	.21
FGD System		
Humidification	800	.70
Entrainment	40	.04
Disposal Water	300	.26
Hydration	20	.02
Pond Evaporation	840	.74
FGD System Total	2,000	1.76
General Plant Use (Cleaning, Sewage Treatment, Backwashing, etc.)	260	.23
Total Water Usage	13,000	11.44
Gross Generating Capacity (MWe)	1,136	
	Eastern	Western
Net Generating Capacity (MWe)	1,072	1,077
Total Water Usage (gpm/MW net)	12.13	12.07

This Table is extracted from Reference 7.

TABLE 19

INVENTORY CAPITAL

Eastern PCF Plant

Material	Quantity	Rate	Cost
Coal	517.00 TPH	21.86 $/Ton	$8,250,200
Limestone	66.60 TPH	10.00 $/Ton	$ 486,180
Maintenance Materials	-	-	$ 591,300
Inventory Capital			$9,327,700

Western PCF Plant

Material	Quantity	Rate	Cost
Coal	651.0 TPH	15.56 $/Ton	$7,394,400
Limestone	10.93 TPH	10.00 $/Ton	$ 79,800
Maintenance Materials	-	-	$ 591,300
Inventory Capital			$8,065,500

This Table is extracted from Reference 7.

TABLE 20

ALLOWANCE FOR FUNDS DURING CONSTRUCTION
FOR PCF UNITS

Plant	Total Plant Investment	Allowance for Funds During Construction
Eastern	$648,845,000	$107,708,000
Western	$629,044,000	$104,421,000

This Table is extracted from Reference 7.

The property taxes and insurance costs are 2.0% peryear to total capital requirement and are included in the levelized fixed charge rate. The capacity factor assumed is 70%.

Operating costs are presented on a 30 year levelized basis. For costs other than fuel, first year costs are multiplied by 1.886, corresponding to 6% escalation and 10% cost of capital. For fuel, first year costs are multiplied by 1.980 (6.4 percent escalation, 10% cost of capital). Table 21 presents a breakdown of PCF plant operating costs. All plant heat rates and efficiencies are based on the plant operating on full load conditions for 70% of the year.

3.4 CONVENTIONAL STEAM PLANT SUMMARY

Table 22 summarizes the conventional steam palnt data as developed from EPRI, GE ECAS, and the Burns & Roe study. In these data, all cost elements have been scaled to 1984 dollars and 658 MWe to permit direct comparison with the CFCC data of Section II.

A direct comparison of scrubber cost is also possible from the conventional plant cost estimating references. The ECAS scrubber cost is expressed as $151/KW to $215/KW (in 1981 dollars), while EPRI assesses $82/KW to $145/KW (in 1976 dollars). These values compare quite favorably with the results of the EPA-funded survey[6] of the actual installed cost of non-regenerable FGD systems at $87/KW, in 1977 dollars. Table 23 compares these scrubber estimates on a consistent dollar basis.

TABLE 21

OPERATING COST BREAKDOWN
FOR 1000 MWe EASTERN AND WESTERN PCF PLANTS

Item		Quantity	Unit Cost	Consumption/ MW Gross	Total Cost $/Yr	First Year Cost mills/kWh	30 Year Levelized Cost mills/kWh
Operating	Eastern	233,960 Mh/yr	-	-	2,859,000	.43	.82
Labor	Western	233,960 Mh/yr	-	-	2,859,000	.43	.82
Maintenance	Eastern	207,250 Mh/yr	-	-	2,087,000	.32	.60
Labor	Western	207,250 Mh/yr	-	-	2,087,000	.32	.60
Maintenance	Eastern	-	-	-	7,096,000	1.08	2.04
Materials	Western	-	-	-	7,096,000	1.08	2.04
Administration	Eastern	.30 x Total	-	-	1,484,000	.23	.42
	Western	O&M Labor	-	-	1,484,000	.23	.43
Fuel	Eastern	517.00 tph	$21.86/ton	910 lb/h	69,302,000	10.54	20.40
	Western	651.00 tph	$15.56/ton	1146 lb/h	62,114,462	9.40	18.68
Limestone	Eastern	66.60 tph	$10.00/ton	117 lb/h	4,084,000	.62	1.17
	Western	10.93 tph	$10.00/ton	19.2 lb/h	670,228	.10	.19
Waste Disposal	Eastern	169.35 tph	$ 8.50/ton	298 lb/h	8,827,000	1.34	2.53
	Western	55.92 tph	$ 8.50/ton	98.5 lb/h	2,914,662	.44	.83
Water	Eastern	13,000 gpm	$.40/1000 gal	11.4 gpm	1,913,000	.29	.55
	Western	13,000 gpm	$.40/1000 gal	11.4 gpm	1,913,000	.29	.55
Other	Eastern	-	-	-	1,000,000	.15	.28
Consumables	Western	-	-	-	1,000,000	.15	.28

Notes:
1. Data based on plants operating at a 70% capacity factor located in mid-continental U.S. area, burning a) eastern coal with a HHV of 10,100 Btu/lb and 4% sulfur, and b) western coal with a HHV of 8,020 Btu/lb and 0.48% sulfur.
2. Gross Generating Output 1136 MWe.
3. Eastern PCF Unit Net Generating Output 1072 MWe; Western PCF Unit Net Generating Output 1077 MWe.
4. Cost based on mid-1978 dollars with a 30-year levelization factor of 1.986 for western coal, 1.935 for eastern coal and 1.886 for all other costs applied to first-year costs.

This Table is extracted from Reference 7.

TABLE 22

CONVENTIONAL STEAM PLANT COST DATA
BASED UPON ONE 658 MW_e PLANT

	EPRI SOUTH EAST	EPRI EAST CENTRAL	EPRI NORTH EAST	GE ECAS 250°F	GE ECAS 175°F	BURNS & ROE EASTERN	BURNS & ROE WESTERN
Plant Installed Cost, $/KW	1086	1266	1333	1028	958	1213	1168
Fuel Cost, $/10^6 BTU	1.65	1.57	1.67	1.21	1.21	1.53	1.37
Capacity Factory 80%							
CoE, Capital Mils/KWH	27.9	32.5	34.2	26.4	24.6	31.2	30.0
CoE, Fuel, Mils/KWH	16.4	15.6	16.6	12.9	12.2	14.9	13.3
CoE, O&M, Mils/KWH	2.9	2.8	3.0	3.1	3.0	2.8	2.8
CoE, Total, Mils/KWH	47.2	50.9	53.8	42.4	39.8	48.9	46.1

NOTE: All Costs Expressed In Year Beginning 1984 Dollars.

TABLE 23

CONVENTIONAL COAL PLANT SCRUBBER COSTS

$1.2\#/10^6$ BTU EMISSION

	$/KW in Stated Year Dollars	$/KW, 1984 Dollars for 658 MWe
ECAS 175°F	151 @ 1981 (795 MWe)	188
ECAS 250°F	215 @ 1981 (747 MWe)	265
EPRI Low	82 @ 1976 (2-1000 MWe)	157
EPRI High	145 @ 1976 (2-1000 MWe)	278
EPA	97 @ 1977 (all plant avg)	---

Section IV

PFB PLANT 1975-76 ECAS COST ESTIMATE

4.1 GE ECAS PFB Plant

A study was peformed in 1975-76 Reference 3, to evaluate advanced energy conversion systems for electric utility base load applications using coal or derived fuels. In this study, the technical/economic characteristics of the PFB plant was also estimated. A conceptual design of this power plant was developed. The performance of this plant in terms of the resulting gross generation, auxiliary power loss, and net station output for plant configuration with 1650°F main bed is given below.

Main Bed Temperature, °F	1650
Steam Cycle Output, Gross MW_e	738.63
Gas Turbine Output, Gross MW_e	205.63
Total Gross Output, MW_e	943.63
Total Auxiliary Losses, MW_e Including Transformer Losses	39.86
Net Power Plant Output, MW_e	903.77

The plant capital cost estimate summary for this PFB plant is given in Table 24.

4.2 Comparison with CFCC Cost Estimate

A direct comparison of the ECAS-PFB in Table 24 and the CFCC cost estimate, in ECAS format is not straightforward. Two factors prevent a direct comparison:

- The original ECAS-PFB was developed in year 1975 dollars with escalation to year 1981. The CFCC was developed in year 1978 dollars with escalation to year 1984. Hence, three additional years escalation is necessary.

- The original ECAS-PFB study was performed for a plant of net 903.8 MWE output while the CFCC plant was designed at 658 MWE output. A scale factor to accommodate this difference is required.

In Table 25 such a common comparison is attempted. To achieve consistent numbers, the following steps were followed:

- The CFCC data and ECAS-PFB data (Tables 1 and 24) were normalized by 658 MW_e and 903.8 MW_e respectively.

- The ECAS-PFB data was escalated by three years to a 1984 basis, using 6.5% per year.

- The ECAS-PFB data was normalized to 658 MW_e through the use of a growth factor of 1.059, the average between the Stearns-Roger value of 1.069 and the EPRI value of 1.049 as developed in Reference 1 and described in Section 3.1 of this report.

The difference then between the original ECAS-PFB estimate and the current CFCC estimate is eleven percent, with the current estimate being higher.

TABLE 24

PLANT CAPITAL COST ESTIMATE SUMMARY
ADVANCED STEAM CYCLE — PRESSURIZED FLUIDIZED BED, 1650 F

COSTS (MILLIONS OF DOLLARS)

CATEGORIES	COMPONENTS	DIRECT LABOR(1)	INDIRECT FIELD(2)	MATERIALS (3)	TOTAL
1.0 PFB Steam Generators	79.19	4.35	3.91	3.10	90.55
2.0 Turbine Generators	50.62	1.70	1.53	.20	54.05
3.0 Process Mechanical Equipment	34.74	6.29	5.66	26.20	72.89
4.0 Electrical		9.52	8.57	11.00	29.09
5.0 Civil And Structural		9.99	8.99	11.20	30.18
6.0 Process Piping And Instrumentation		13.51	12.16	20.10	45.77
7.0 Yardwork And Miscellaneous		1.59	1.43	1.70	4.72
	164.55	46.95	42.25	73.50	327.25

B.O.P. Labor, Materials & Indirect (Sum of 1+2+3)	162.70
A/E Home Office & Fee @ 15%	24.41
Total Plant Cost	351.66
Contingency @ 20%	70.33
Total Capital Cost	421.99
Escalation & Interest During Construction	231.20
Total M $	653.10
Plant Output MWE	903.80
TOTAL $/KWE	722.8

NOTE: All costs on this page are expressed in mid year 1975 dollars excluding adders on escalation & interest during construction. Total installed capital cost is in year beginning 1981 dollars.

TABLE 25
COMPARISON OF ECAS-PFB AT 658.3 MWe WITH CFCC COST ESTIMATE
CAPITAL COST COMPARISON ($/kW)

	Component		Direct Labor(1)		Indirect Field(2)		Materials(3)		Total	
	CFCC	ECAS-PFB	CFCC	ECAS-PFB	CFCC	ECAS-PFB	CFCC	ECAS-PFB	CFCC	ECAS-PFB
1.0 PFB Steam Generator	52.6	112.1	21.7	6.2	19.4	5.5	4.6	4.4	98.3	128.2
2.0 Turbine Generators	91.3	71.6	3.0	2.4	2.7	2.2	1.4	0.3	98.4	76.5
3.0 Process Mechanical	87.0	49.2	34.9	8.9	31.4	8.0	1.2	37.1	154.5	103.2
4.0 Electrical	26.9		9.7	13.5	8.8	12.1	1.2	15.6	46.6	41.2
5.0 Civil & Structural			7.0	14.1	6.2	12.7	10.9	15.9	24.1	42.7
6.0 Process Piping & Instrumentation			22.0	19.1	19.7	17.2	36.3	28.4	78.0	64.7
7.0 Yardwork & Misc.			3.6	2.3	3.2	2.0	5.5	2.4	12.3	6.7
Totals	257.8	232.9	101.9	66.5	91.4	59.7	61.1	104.1	512.2	463.2

	CFCC	ECAS-PFB
BOP Labor, Material & Indirects (Sum of 1+2+3)	254.4	230.3
A/E Home Office and Fee @ 15% of (1+2+3)	38.2	34.5
Total Plant Cost	550.4	497.7
Contingency @ 20% of Total Plant	110.1	99.5
Total Capital Cost	660.5	597.2
Escalation and Interest	362.0	327.3
Total Installed Capital Cost	1022.5	924.5

Operating Cost Comparison

	ESCAS-PFB	CFCC
Installed Cost ($/kW)	924.5	1022.5
Fuel Cost, $/$10^6$ Btu	1.2	1.2
Cost of Electricity, Capital (mils/kWh)	23.7	26.3
Cost of Electricity, Fuel	10.5	10.0
Cost of Electricity, O&M, Dolomite	3.0	4.2
Cost of Electricity Total (mils/kWh)	37.2	40.5

NOTE: All costs on this page are expressed in midyear 1978 dollars/kW excluding escalation and interest during construction. Total installed capital cost is in year beginning 1984 dollars.

Section V

REFERENCES

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