Comparative Study and Evaluation of Advanced Cycle Systems

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Appendix A

PHASE 1 POWER CYCLES DATA TABULATION

This appendix contains descriptive data for each of the 19 advanced cycles analyzed in Phase 1, as well as data for two reference cycles (20 and 21).

Table A-1 is a tabulation of all 21 cycles, giving the type of furnace, the fuel, and the source of data. For each cycle that uses data from the ECAS program,* the NASA case number corresponding to that cycle is indicated. The table also indicates those new cases for which data were generated in the present EPRI program.

Tables A-2 through A-4 summarize the technical descriptions and performance data for the 21 cycles, as well as the estimated R&D program costs and year of first commercial service. The R&D costs do not include the cost for development of gasifiers, furnaces or stack gas scrubbers. Likewise the R&D time required for these subsystems is not included in the time estimates for date of first commercial service.

Capital costs and the costs of electricity for these cycles are summarized in Tables A-5 and A-6. Note that the cost of electricity presented in Table A-6 is a levelized, life-cycle cost as described in Section 3.

Note that the fuel costs and escalation rates quoted in Table A-6 are different from those used in the Phase 3 comparisons. Oil, coal, and coal derived fuel prices are assumed to escalate at 6½%. The nuclear fuels were assigned the escalation patterns shown in Table A-7. The fuel, O&M and capital charges to cost of electricity have all been levelized in Table A-6 in a manner consistent with that described in Section 3. See Appendix D, Tables D-5 through D-8 for the levelized values of these costs.

*J.C. Corman, G.R. Fox, et al., Energy Conversion Alternatives Study (ECAS), Phase I Final Report, NASA Report No. NASA-CR 134948, NASA Contract NAS 3-19406, Corporate Research and Development, General Electric Company, Schenectady, New York, February 1976.

Table A-1
CYCLES EVALUATED IN PHASE 1

Cycle	Fuel	Case Number
1. Advanced steam, atmospheric fluidized bed furnace	Coal	NASA Case 12
2. Advanced steam, conventional furnace	No. 6 oil	New EPRI Case
3. Advanced steam, high temperature gas-cooled reactor	Nuclear	New EPRI Case
4. Advanced steam, liquid metal fast breeder reactor	Nuclear	New EPRI Case
5. Advanced open cycle gas turbine, recuperative, air cooled	High-Btu gas derived from coal	NASA Case 19
6. Advanced open cycle gas turbine, recuperative, air cooled	No. 6 oil	New EPRI Case
7. Advanced open cycle gas turbine, combined cycle, air cooled	Low-Btu gas derived from coal	NASA Case 14
8. Advanced open cycle gas turbine, combined cycle, water cooled	Low-Btu gas derived from coal	NASA Case 9
9. Advanced open cycle gas turbine combined cycle, water cooled	Liquid semiclean fuel derived from coal	NASA Case 5
10. Closed cycle gas turbine, supercritical carbon dioxide, atmospheric fluidized bed	Coal	NASA Case 26
11. Closed cycle gas turbine, helium, atmospheric fluidized bed	Coal	NASA Case 20
12. Closed cycle gas turbine, helium, high temperature gas-cooled reactor	Nuclear	New EPRI Case
13. Open cycle plasma MHD	Coal	NASA Case 1
14. Closed cycle plasma MHD, conventional furnace	Coal	NASA Case 102
15. Liquid metal MHD, atmospheric fluidized bed	Coal	NASA Case 101
16. Metal vapor turbine, atmospheric fluidized bed	Coal	NASA Case 1
17. Thermionic, conventional furnace	Coal	New EPRI Case
18. Fuel cell, low temperature	Hydrogen derived from coal	NASA Case 8
19. Fuel cell, low temperature	No. 6 oil	New EPRI Case
20. Conventional steam with stack gas scrubbing (reference case for base load and midrange)	Coal	NASA Case 51
21. Simple cycle gas turbine (reference case for peaking)	High-Btu gas derived from coal	NASA Case 1

Table A-2
CYCLE PARAMETERS—CLOSED RANKINE CYCLES

Cycle Parameters	Cycle Number					
	1	2	3	4	16	20 Reference Cycle
Net Output (MWe)	745	763	1180	1000	1088	762
Energy Source	AFB	CF	HTGR	LMFBR	AFB	CF/SCRB
Fuel	Coal	Oil	Uranium	Uranium	Coal	Coal
Prime Cycle:						
Working Fluid	Steam	Steam	Steam	Steam	Potassium	Steam
Turbine Inlet Temperature (F)	1000	1000	955		1400	
Turbine Inlet Pressure (psia)	3515	3515	2515			
Reheat Temperature (F)	1200	1200	1000			
Condenser Temperature (F)					1100	
Pressure (in-HGA)	1.5	1.5	1.5			
Bottoming Cycle:						
Working Fluid					Steam	
Turbine Inlet Temperature (F)					1000	
Turbine Inlet Pressure (psia)					3515	
Reheat Temperature (F)					1000	
Condenser Pressure (in-HGA)					1.5	
Heat Rejection	WCT	WCT			WCT	
Thermodynamic Efficiency %	45.1	45.1			51.4	44.0
Powerplant Efficiency %	37.5	38.8	39.3	38	38.9	37.1
Overall Efficiency %	37.5	38.8			38.9	37.1
Estimated Cost of R&D (M\$)	20	20	300	8000	250	—
Estimated Date of First Commercial Service	1987	1987	1985	2000	1992	—

Legend: Coal - Illinois No. 6
Oil - No. 6
AFB - Atmospheric Fluidized Bed
CF - Conventional Furnace

HTGR - High Temperature Gas Cooled Reactor
LMFBR - Liquid Metal Fast Breeder Reactor
CF/SCRB - Conventional Furnace with Flue
Gas Scrubbers
WCT - Wet Cooling Towers

Table A-3
CYCLE PARAMETERS-GAS TURBINE CYCLES

Cycle Parameters	Cycle Number								
	5	6	7	8	9	10	11	12	21 Reference Cycle
Net Output (MWe)	111	83.4	677	997	728	563	388	1160	82.9
Energy Source	GT/Comb	GT/Comb	GT/Comb	GT/Comb	GT/Comb	AFB	AFB	HTGR	GT/Comb
Fuel	HBtu	Oil	LBtu	LBtu	SCL	Coal	Coal	Uranium	HBtu
Prime Cycle (Gas Turbine):									
Working Fluid	Products	Products	Products	Products	Products	Closed Supercritical CO ₂	Closed Helium	Closed Helium	Products
Turbine Inlet Temp. (F)	2600	2200	2400	3000	2800	1350	1500	1500	2100
Compressor Pressure Ratio	16	12	12	16	16	2.7	4.0		12
Recuperator Effectiveness	0.85						0.85		
Recuperator $\Delta P/P$	0.05	0.05				0.05	0.03		
Gas Path Pressure Drop (in-H ₂ O)			20	20	20				
Turbine Cooling Fluid	Air	Air	Air	Water	Water				Air
Compressor Inlet Temp. (F)	59	59	59	59	59	80	80		59
Bottoming Cycle:									
Working Fluid			Steam	Steam	Steam				
Turbine Inlet Temp (F)			950	1000	1000				
Turbine Inlet Pressure (psia)			1250	1465	1465				
Condenser Pressure (in-HGA)			1.5	1.5	1.5				
Heat Rejection			WCT	WCT	WCT	WCT	WCT		
Thermodynamic Efficiency %	37.0	35.0			48.5	42.7	38.3		29.9
Powerplant Efficiency %	36.7	34.5	36.2	35.3	47.0	35.7	31.6	36.5	29.6
Overall Efficiency %	18.5	34.5	36.2	35.3	36.7	35.7	31.6		14.9
Estimated Cost of R& D M\$	50	50	50	125	150	300	200	500	—
Estimated Date of First Commercial Service	1985	1980	1984	1987	1988	1995	1987	1990	—

HBtu - High Btu Gas Derived from Coal at Offsite Facility
Oil - No. 6 Oil
LBtu - Low Btu Gasifier Integrated with Plant

GT/Comb - Gas Turbine Combustor
SCL - Semiclean Liquid Fuel Derived from
Coal Offsite

Products- Combustion Products
WCT - Wet Cooling Tower
Coal - Illinois No. 6
HTGR - High Temperature Gas Cooled Reactor

Table A-4
CYCLE PARAMETERS-DIRECT ENERGY CONVERSION CYCLES

Cycle Parameters	Cycle Number					
	13	14	15	17	18	19
Net Output (MWe)	1895	930	559	955	201	50
Energy Source	Comb	CF	APB	CF	Fuel Cell	Fuel Cell
Fuel/Oxidizer	Coal/Air	Coal/Air	Coal/Air	Coal/Air	H ₂ /O ₂	Oil/O ₂
Prime Cycle Name:	Open Cycle MHD	Closed Cycle MHD	Closed Cycle MHD	Thermionic	Fuel Cell	Fuel Cell
Working Material	Prod/Seed	Argon/Seed	Sodium/Hellum		Solid Polymer Electrolyte	Solid Polymer Electrolyte
Inlet Pressure (psia)	132	147	735			
Inlet Temperature (F)	4634	3121	1300			
Emitter Temperature (F)				1880-2420		
Collector Temperature (F)				845		
Operating Temperature (F)					300	300
Current Density (A/ft ²)					300	300
Electrolyte Thickness (in.)					0.005	0.005
Bottoming Cycle:						
Working Fluid	Steam	Steam	Steam	Steam		
Turbine Inlet Temperature (F)	1000	1000	1000	1000		
Turbine Inlet Pressure (psia)	3515	3515	3515	3515		
Reheat Temperature (F)	1000	1000	1000	1000		
Condenser Pressure (in-Hg/A)	1.5	1.5	1.5	1.5		
Heat Rejection	WCT	WCT	WCT	WCT		
Thermodynamic Efficiency %	52.8	55.9	44.2	48.4		
Powerplant Efficiency %	49.2	46.0	36.7	44.2	51.1	42.5
Overall Efficiency %	48.3	46.0	30.7	44.2	31.1	
Estimated Cost of R&D (M\$)	800	800	450	140	100	100
Estimated Date of First Commercial Service	1997	2000	1991	1997	1992	1992

Comb - Combustor
Coal - Illinois No. 6
Prod/Seed - Combustion Products Seeded with Potassium
WCT - Wet Cooling Tower

CF - Conventional Furnace
Argon/Seed - Argon Seeded with Cesium
APB - Atmospheric Fluidized Bed

H₂/O₂ - Hydrogen Derived from Coal and
Oxygen Produced at Offsite Facilities
Oil/O₂ - No. 6 Oil, Oxygen Produced Onsite

Table A-5
CAPITAL COST SUMMARY

Capital Cost Summary		Cycle Number																				
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Plant Construction Time	Years	5	5	8	9	1	1	3	4	4	5	4	8	5	6	6	6	7	3	3	5	1
Major Components																						
Primary Heat Input or Fuel System	M\$	48.7	31.6			—	—	92.0	120.8	—	97.8	68.2		33.6	75.4	74.6	278.5	50.2	—	—	32.7	—
Prime Cycle	M\$	56.8	55.7			13.9	10.8	38.6	52.0	47.0	241.2	40.1		112.7	37.9	46.0	60.1	117.6	15.4	16.1	27.4	7.2
Bottoming Cycle	M\$	—	—			—	—	28.3	29.1	26.0	—	—		54.8	38.6	16.9	38.0	26.0	—	—	—	—
Balance of Plant Cost	M\$	210.7	205.0			2.2	2.1	50.6	74.9	59.4	172.5	78.3		931.4	452.2	552.8	372.7	451.9	20.3	6.6	272.5	2.1
Contingency	M\$	63.2	58.5			3.2	2.6	41.8	55.3	26.5	102.4	37.3		226.5	120.8	138.0	149.7	90.4	7.1	4.5	66.6	1.9
Total Estimated Plant Cost in 1975 Dollars	M\$	379.4	350.8	749.2	717.5	19.3	15.5	251.3	332.1	158.9	613.9	223.9	824.1	1359.0	724.9	828.3	899.0	736.1	42.8	27.2	399.2	11.2
Plant Cost in Year Construction Starts	M\$	1338	1236	2185	1965	87.6	70.3	1005	1246	597	2164	840	2404	4222	2398	2740	2971	2287	171.5	108.7	1407	50.8
Escalation and Interest During Construction	M\$	651	602	1963	2085	7.0	5.7	269	464	222	1054	313	2159	3158	1467	1677	1819	1710	45.8	28.4	685	4.1
Capital Cost in Year 2000 when Plant Enters Service	M\$	1989	1838	4148	4050	94.6	76.0	1274	1710	819	3218	1153	4563	7380	3866	4417	4790	3997	217.3	137.1	2092	54.9
Capital Cost Expressed in 1975 Dollars	M\$	412	381	859	839	19.6	15.7	264	354	170	666	239	945	1529	801	915	992	828	45	28.4	433	11.4
Cost Per Installed kW in 1975 Dollars	\$/kW	553	499	728	839	177	189	390	355	233	1184	615	801	807	861	1636	912	867	224	568	569	137

Table A-6
COST OF ELECTRICITY SUMMARY

Cost of Electricity Summary	Cycle Number																				
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Cost of Electricity* (mills/kWh)																					
Capacity Factor = 0.70	38.8	56.5	45.6	42.8	61.1	52.3	35.2	34.8	39.7	57.6	43.1	49.1	43.0	48.3	71.5	51.4	49.8	58.0	58.8	38.8	73.5
Capacity Factor = 0.40	51.0	67.5	61.6	67.9	65.0	56.5	43.8	42.6	44.8	83.7	56.7	66.8	60.8	67.3	107.6	71.4	68.9	62.9	71.3	51.3	76.5
Capacity Factor = 0.15	98.3	110.2	124.0	165.5	80.2	72.7	77.2	73.0	64.8	185.0	109.3	135.4	129.9	141.0	247.6	149.5	143.1	82.1	119.9	100.0	88.2
Plant Capital Cost Expressed in 1975 Dollars \$/kW	553	499	728	839	177	189	390	355	233	1184	615	801	807	861	1636	912	867	224	568	569	137
Capital Cost Escalation Rate %/yr	6.5	Variable																			
Capital Cost Contribution to Cost of Electricity (mills/kWh) 18% Levelized* Fixed Charge Rate																					
Capacity Factor = 0.70	16.3	14.7	21.4	33.5	5.2	5.5	11.5	10.4	6.8	34.8	18.1	23.5	23.7	25.3	48.0	26.8	25.5	6.6	16.7	16.7	4.0
Capacity Factor = 0.40	28.5	25.7	37.4	58.6	9.1	9.7	20.0	18.2	12.0	60.8	31.6	41.2	41.5	44.2	84.0	46.9	44.5	11.5	29.2	29.2	7.0
Capacity Factor = 0.15	78.8	68.4	99.7	156.3	24.3	25.9	53.4	48.6	31.9	162.2	84.3	109.7	110.6	118.0	224.1	124.9	118.8	30.7	77.8	78.0	18.8
Fuel Cost in Year 1975** \$/MWh	1.00	2.20	0.53	0.21	3.00	2.20	1.00	1.00	2.07	1.00	1.00	0.53	1.00					2.88	2.20	1.00	3.00
Fuel Cost Escalation Rate %/yr	6.5	Variable		Variable	6.5	Variable							Variable	6.5							
Fuel Cost Contribution to Cost of Electricity* mills/kWh	17.1	36.4	17.7	1.1	52.5	41.0	17.7	18.2	28.3	18.0	20.3	19.0	13.3	14.0	17.5	16.5	14.5	42.6	33.3	17.3	65.1
O&M Cost in Year 1975																					
Fixed \$/kW yr	0																				
Variable mills/kWh	2.89	2.89	3.48	4.33	1.80	3.09	3.20	3.30	2.42	2.58	2.53	3.51	3.20	4.83	3.20	4.30	5.23	4.70	4.70	2.53	2.32
O&M Cost Escalation Rate %/yr	6.5																				
O&M Cost Contribution to Cost of Electricity* mills/kWh	5.4	5.4	6.6	8.2	3.4	5.8	6.0	6.2	4.6	4.9	4.8	6.6	6.0	9.1	6.0	8.1	9.8	8.8	8.8	4.3	4.3

*Levelized Cost in Year 2000 Expressed in 1975 Dollars

**These fuel costs were selected for the Phase 1 comparisons; they are different from the costs used in the rest of this report; see text for explanation.

Table A-7
NUCLEAR FUEL ESCALATION PATTERNS

	Fuel For HTGR	Fuel For LMFBR
Base Price (1975\$) \$/MBtu	.53	.21
Escalation Rate (%/yr) for the Period:		
1975-1979	6.5	4.7
1980-1984	6.5	4.5
1985-1989	8.7	4.4
1990-1994	11.1	4.1
1995-1999	10.0	3.8
2000-2004	9.0	3.4
2005-2009	8.7	2.9
2010-2014	8.9	- 7.3
2015-2019	7.7	-19.3
2020-2024	6.5	6.5
2025-2029	6.5	6.5

Appendix B

PHASE 2 POWER CYCLES — CONCEPTUAL DESIGNS

Following the screening of 19 advanced power cycles in Phase 1 of this contract, the following two cycles were chosen for further study in Phase 2:

- Open cycle gas turbine combined-water cooled- low Btu gasifier-coal
- Advanced steam cycle (16,550 kPa/811 K/922 K [2400 psi/1000 F/1200 F])

Conceptual designs were evolved for these cycles in enough detail to specify equipment configuration and plant layouts. This yielded a more precise description of cost and performance for the two cycles than was possible in Phase 1. These results are reported in Sections B.1 and B.2 below.

Development plans were also constructed for the two Phase 2 cycles. These are reported in Section B.3.

Four conventional power generation concepts are described in Section B.4:

- Conventional open cycle gas turbine-oil/semiclean liquid fuel
- Conventional open cycle gas turbine combined-oil/semiclean liquid fuel
- Conventional steam-wet gas scrubbers-coal
- Conventional steam-light water reactor

These are the reference cycles used in the Phase 3 evaluations.

B.1 OPEN CYCLE GAS TURBINE COMBINED—WATER COOLED—LOW-BTU GASIFIER

INTRODUCTION

The open-cycle gas turbine combined power plant presented in this section utilizes low-Btu (LBtu) gas produced from Illinois No. 6 coal. The cycle was designed to meet emission specifications for plants burning solid fuels that allow a maximum SO_x emission from the plant of 0.52 kg/GJ (1.2 lb/MBtu)—based on the higher heating value (HHV) of coal—and a maximum NO_x emission of 0.30 kg/GJ (0.7 lb/MBtu). These emission goals were met by employing appropriate fuel gas cleanup systems.

The simplified cycle schematic, Figure B-1, identifies major cycle components and their interconnections; Table B-1 defines major system parameters.

Figure B-1. Simplified Schematic Diagram for Open Cycle Gas Turbine Combined--Water Cooled--LBtu Gasifier

The fixed bed gasifiers generate LBtu gas which is chemically treated in the gas cleanup system so that the clean fuel supplied to the gas turbine combustors can meet the applicable SO_x emission standards. Illinois No. 6 coal is fed to the gasifiers. The process air required for the gasification process is extracted from the main gas turbine compressors. The process water supplied to the gasifier is preheated in the cleanup system.

The prime cycle consists of two water-cooled gas turbine units, having a 16:1 compression ratio and 1922 K (3000 F) firing temperature (that is, the temperature at the inlet of the

Table B-1
CYCLE PARAMETERS

OPEN CYCLE TURBINE COMBINED—WATER COOLED-LBTU GASIFIER
(Solid Fuel Emission Specifications)

PARAMETER	VALUE OR DESCRIPTION
FUEL	
LBtu Gas (Wet Basis)	HHV = 3124 Btu/lb, LHV = 2911 Btu/lb
Composition (Wt)	
S (as H ₂ S + COS)	0.14%
NH ₃	0.04%
GASIFIER	
Type	Fixed Bed
Operating Pressure (psia)	351
Cleanup System	Alkazid + Claus for H ₂ S Removal
PRIME CYCLE	
Gas Turbine	Water Cooled
Ceramic parts	Combustor Liner
	Transition Piece
	Stage 1 Nozzle
Turbine inlet temperature (F)	3000
Compressor pressure ratio	16:1
Working fluid	Combustion Gas
Turbomachinery configuration	Axial Flow
Turbine exhaust	Axial, 1458 F
HEAT EXCHANGER (S)	
Heat Recovery Steam Generator	
Vapor generator pinch point ΔT (F)	70
Exit ΔT (F)	80
Gas side $\Delta P/P$	0.05
Drum to throttle $\Delta P/P$	0.11
Reheater $\Delta P/P$	0.10
Economizer $\Delta P/P$	0.008
BOTTOMING CYCLE	
Steam Bottoming Cycle	
Throttle temperature (F)	1000
Throttle pressure (psi)	2400
Reheat temperature (F)	1000
Condensing pressure (in. Hga)	2.3
Feedwater temperature (F)	262
HEAT REJECTION	
Wet Cooling Tower	8 cells
Stack Temperature (F)	300

first-stage rotor). Some of the stationary components—combustor, transition piece, and turbine first-stage nozzles—are made of silicon carbide ceramic material requiring no cooling flows. The remaining stationary and rotating stages are cooled by circulating water loops which are coupled with the feedwater train of the steam bottoming cycle. About two-thirds of the total electrical power of the output power plant is derived from the prime cycle. The gas turbine exhaust temperature is 1065 K (1458 F).

Energy from the exhaust gas is recovered by cooling it to the stack discharge temperature level and supplying this energy to the steam bottoming cycle. The steam cycle has 16550 kPa/811 K (2400 psig/1000 F) throttle conditions, with a reheat stage at 811 K (1000 F). The condensing pressure is 7.8 kPa (2.3 in. Hga). The steam cycle includes two identical heat recovery steam generator (HRSG) units and a steam turbine-generator unit. About one-third of the total plant power output is contributed by the steam cycle. The steam plant also provides steam for the booster-compressor drive turbine and the process steam required for the gas cleanup system.

Since the plant was designed for baseload service, no provision for gas turbine exhaust bypass around the HRSG was made.

Heat rejection to the cooling tower occurs from the bottoming cycle steam turbine, from the booster-compressor drive turbine, and from the gas cleanup system. This plant requires 8 mechanical draft wet cooling towers. Forced draft cooling tower cells and corresponding circulating water pumps provide the cooling water for the condenser. Cooling tower cell evaporation and blowdown water losses are replaced continuously so that the prescribed cooling tower performance and the required 7.8 kPa (2.3 in. Hga) turbine backpressure are assured. The net power output from this plant is 640.0 MW (640.0 MWe), with the overall energy efficiency from coal of 44.0 percent.

CYCLE DESCRIPTION

Figure B-2 is a detailed cycle schematic showing the interconnections between major cycle components and the corresponding flow rates and thermodynamic state point data. For the purposes of discussion, the cycle is divided into six categories:

- LBTu fuel plant
- Gas cleanup system
- Gas turbine system
- HRSG-steam turbine system
- Feedwater system
- Steam extractions

Note

Pressure (psia) / Temperature (°F) / Flow Rate (x 10⁶ Lb/hr) / Enthalpy (Btu/lb) (REF = 32°F)

Flow Rate ($\times 10^6$ Lb/hr)

**Figure B-2. Schematic Diagram for Open Cycle Gas Turbine Combined:
Water Cooled--LBtu Gasifier**

LBtu Fuel Plant

The advanced fixed bed gasifier, producing an LBtu fuel gas, has two major characteristics:

1. It handles more coal fines than state-of-the-art fixed bed gasifiers.
2. It allows maximum tar recycle.

The ability to use more fines permits the use of conventional, low-cost coal crushing equipment. For ease of separating coal fines, the incoming coal feed is first dried and then crushed to obtain 25 percent of the coal as fines. After the fines separation the crushed coal passes through a spray station, where the coal moisture is restored to the original level, and is then fed to the coal hoppers. The separated fines are mixed with the recycle tar in a mixer; the mixture is extruded and fed to a screw conveyor feeding to the gasifier vessel.

The gasifier walls in the oxidation zone are cooled by the circulating jacket cooling water. Water at 450 K (350 F) is supplied to the jacket from the gas cleanup system; the circulating water is flashed in a drum, and the vapor generated is introduced into the gasifier vessel as part of the steam required for the gasification process. The gasifier process air is extracted from the main compressor; this air is saturated with water which serves as the remainder of the gasification process water requirement. A steam-driven booster compressor raises the pressure and delivers this air to the gasifier vessel.

The raw LBtu gas leaves the gasifier vessel at 757 K (904 F). This gas passes through a series of saturator/washer-cooler vessels (two vessels per gasifier vessel): the first vessel separates heavy tar from the raw gas, and the second vessel separates light tar oil, naphtha, and phenols. A major fraction of the heavy tar is recycled back to the gasifier vessel, either mixed with coal fines or by direct injection into the vessel. Saturated raw gas leaving the second vessel at 437 K (328 F) enters the gas cleanup system.

Gas Cleanup System

In order to meet the solid fuel emission standards, the hydrogen sulfide (H_2S) content of the raw gas must be reduced significantly. The Alkazid process,* selected here for this purpose, requires that the gas be cooled to 310 K (100 F). The H_2S removed from the gas is converted to elemental sulfur in a Claus plant.

The cleanup system includes an incinerator which oxidizes the heavy tar blowdown, the lockhopper vent gas, and the tail gas from the Claus plant. The thermal energy released through incineration is used to generate process steam and to heat process water. This

*See pages B-66 through B-72 for more detailed description of Alkazid process.

internally generated process steam supplements the steam (at 45 kPa [65 psi]) imported from the steam bottoming cycle to meet the steam requirements of the Alkazid H₂S recovery unit.

The cleanup system requires a process water flow input; some of this water is heated to 450 K (350 F) and is supplied as gasifier jacket cooling water. The cleanup system also has substantial heat rejection to the cooling tower, for which 4.5 Mkg (10 Mlb) of cooling water per hour is required.

The clean gas finally leaving the cleanup system is saturated at 416 K (290 F). The light tar oil, phenols, and naphtha removed from the raw gas stream earlier are added to the clean fuel gas. In order to avoid condensation in the fuel line, the gas is superheated to 430 K (315 F) in a fuel-gas preheater before it is supplied to the combustor.

Gas Turbine System

This cycle has two water-cooled gas turbines, with a 16:1 compressor pressure ratio and a 1922 K (3000 F) firing temperature (average temperature at the inlet of the first-stage rotor). The combustor liners, the transition pieces, and the first-stage nozzles are made of ceramic materials requiring no cooling flows. The remaining two nozzle stages and all three rotor stages are cooled by nozzle and bucket coolant loops, respectively. Blocking air extracted from the two intermediate compressor stages is cooled through evaporation of treated water; this air is used for turbine wheel-space blocking.

Since the fuel gas contains adequate moisture, additional steam injection in the combustor for the purpose of NO_x suppression is not required. Each gas turbine unit produces a net electric power of 228.2 MW (228.2 MWe) and has an exhaust gas temperature of 1065 K (1458 F).

HRSG-Steam Turbine System

The heat recovery steam generator unit extracts thermal energy from the gas turbine exhaust flow stream and produces steam for use in a steam turbine system. One HRSG unit is provided for each gas turbine.

The HRSG unit consists of a horizontal reheater/superheater section followed by a vertical section comprising an evaporator, an economizer, and a drum. The combustion gas entering the HRSG unit at 1065 K (1458 F) is cooled down to 445 K (342 F) at the exit of the economizer. The combustion gases pass through a silencer before entering a stack. A fraction of the stack gas (~15 percent) is used to dry the coal in a coal dryer and is returned to the stack. The temperature of the gas discharging through the stack is 422 K (300 F).

The steam cycle conditions are selected to be 16,550 kPa (2400 psig) and 811 K (1000 F) at throttle, with a single reheat stage at 811 K (1000 F). The feedwater temperature is 401 K (262 F), and the condensing pressure is 7.8 kPa (2.3 in. Hga). One steam turbine serves both HRSG units, with a net power output of 208.6 MW.

Feedwater System

Steam condensates from the main steam turbine and the booster turbine, along with the treated makeup water, are pumped to the deaerator tank by a condensate pump. The deaerator tank at 210 kPa (30 psia) removes noncondensable gases from the feedwater. The feedwater is then pumped to the high-pressure economizer.

The feedwater heater train receives thermal energy input from three sources:

Bucket Coolant Loop. Cooling water at 310 K (100 F) and 1720 kPa (250 psia) is supplied to the turbine for the purpose of cooling all three rotor stages. The coolant, in turn, picks up the heat; about two-thirds of the coolant flow is vaporized and is lost in the gas path; the remaining one-third of the flow is collected in the stationary water collection area. The recovered bucket coolant is cooled while heating the feedwater in a closed heater and mixed with the makeup water before passing through a polish stage to restore water purity.

Nozzle Coolant Loop. This is a closed loop system which cools the second and third stage turbine nozzles. Cooling water is supplied from the deaerator tank and pumped to 10,340 kPa (1500 psi) and 398 K (257 F) level. The water leaving the nozzles at 540 K (512 F) is first used to preheat the fuel gas and is then supplied to a 480 kPa (70 psi) flash tank, where saturated steam is produced for use in the gas cleanup system. The saturated liquid from the flash tank is supplied back to the deaerator tank.

Steam Extraction from Turbine. In order to maintain the feedwater enthalpy of 509 kJ/kg (219 Btu/lb) at the deaerator exit, steam is extracted from the steam turbine at 220 kPa (32 psi) and supplied to the deaerator tank.

Steam Extractions

The cycle has three steam extractions from the steam turbine:

For the Booster-Compressor Drive Turbine. Steam from the cold reheat point (that is, after expansion through the high-pressure turbine) is supplied to the two steam turbines driving the booster compressors. The condensing conditions are taken at 7.8 kPa (2.3 in. Hga). Part of the condensate is sprayed into the air saturator and the desuperheater, and the remainder is pumped back to the feedwater train.

For the Gas Cleanup System. The external process steam demand for the gas cleanup system is satisfied by extracting steam at 550 kPa (79 psi) from the steam turbine and mixing it with the condensate from the booster-compressor drive turbine.

For the Feed Heating Train. As mentioned above, steam at 220 kPa (32 psi) is extracted to maintain desired feedwater conditions.

MAJOR CYCLE COMPONENTS

The design and performance details of the following cycle components are provided in this subsection:

- Low-Btu Fuel Plant, including
 - Advanced fixed bed gasifier, describing gasification process characteristics and a cross section of the gasifier vessel
 - Gasification module, indicating the arrangement of 12 gasifier vessels and associated equipment which form the fuel plant
 - LBtu gas cleanup system, designed to meet solid fuel emission standards
- Prime Cycle Components
- Bottoming Cycle Components, including
 - Heat recovery steam generators
 - Steam turbine-generator
- Materials of Construction for the above components.

Low-Btu Fuel Plant

The LBtu fuel plant consists of a gasification module and a gas-cleanup system. The gasification module includes 12 advanced fixed bed gasifiers and the associated coal preparation equipment (dryer and spray stage) along with other material handling systems, including coal dryer, coal crusher, mixer, extruder, and lockhoppers. It also includes the wash coolers (two coolers for each gasifier) for the removal of tar and oils from the fuel gas. The cleanup system is designed to treat the fuel gas so that the desired emission standards for the plant are met.

Advanced Fixed Bed Gasifier.

The gasifier design differs significantly from current state-of-the-art fixed bed gasifiers (Ref. B-1). Improvements in gasifier design and operation are believed to be feasible; some have already been demonstrated in a medium-scale gasifier. For several years the U.S. Bureau of Mines has been operating a pressurized fixed bed gasifier that has shown

the feasibility of operating at low steam/air ratios in the blast and has also demonstrated the advantages of using bed-stirring devices both to increase throughput and to achieve capability of gasifying caking coals typical of the Midwest and Eastern U.S. (Refs. B-2 and B-3). The General Electric Company has demonstrated a number of innovations in its on-going coal gasification program (Ref. B-4) and is currently in the early operational stage of a midscale, experimental pressurized fixed bed gasifier incorporating these features (Ref. B-5). The fixed bed gasifier design discussed here is based on these efforts.

Gasifier Characteristics. The advanced fixed bed gasifier differs from other "conventional" fixed bed gasification systems (e.g., Lurgi) in three principal areas:

- More tar cracking
- Coal fines handled by extrusion
- Lower steam/air ratio

By comparison with a conventional fixed bed gasifier, several significant performance and cost gains are realized as a result of these features:

1. A larger fraction of the heavy tar separated from the raw product gas is recycled back to the gasifier, thereby reducing the heavy tar blowdown rate to the minimum. In the present study, the blowdown rate was 0.0008 kg tar/kg coal (0.0008 lb tar/lb coal); this results in a smaller size incinerator and its associated heat exchanger train.

The capability for handling larger amounts of heavy tar recycle than a conventional fixed bed gasifier results from the selected design approach. Here a large amount of the tar enters in the form of an extruded cake of tar and coal fines which is broken into large chunks in the extrusion process and will not clog the top of the bed. The remaining heavy recycle tar is sprinkled on top of the bed. The upper stirring arm in the gasifier will break up agglomerations of tar and coal, permitting acceptance of larger amounts of tar before clogging becomes troublesome.

2. The coal fines are mixed with part of the heavy recycle tar prior to extrusion; hence a larger fraction (25 percent of total coal feed in the present study) of the fines can be utilized in the feed. This can result in lower coal costs through the use of run-of-the-mine coals and allows the use of conventional and less expensive coal crusher equipment. In addition, since only 75 percent of the coal is fed to the gasifier via lockhoppers, the number of lockhopper cycles is reduced by 25 percent, and therefore lockhopper losses are reduced 25 percent; the cost of extruders is incurred in reducing the lockhopper losses.

3. The ratio of process steam to process air supplied to the gasifier used in this study is 0.2, compared with a value of 0.7 as normally specified for a standard fixed bed gasifier. Steam input requirements are satisfied by a combination of the jacket steam and the water injection in the process air stream (air blast). No additional external steam from the steam bottoming cycle is required for the gasifier system beyond that needed for the cleanup system and booster-compressor drive turbine. Part of the condensate is injected into the air blast.

In the present gasifier design, an upper bed agitator is provided over the grate. This agitator, along with expected grate improvements, provides greater capability for breaking up clinkers. As a result, it is possible to run at lower steam blast rates. The steam blast serves a dual function in the gasifier in that it supplies water for reaction with the coke in the reaction zone and also serves as a coolant to the combustion zone, which is intended to keep the ash from reaching the ash fusion temperature. It is important to provide enough steam to meet the requirements for chemical reaction and ash temperature control, but excess steam will cause excessive cooling and is wasted. As a result, a steam/air ratio of 0.2 was used in this study. It should be pointed out here that the Bureau of Mines gasifier, which runs on Illinois No. 6 coal, used a steam/air ratio of 0.135 without encountering troublesome clinkering. Steam/air ratios below these levels will not provide enough steam for the chemical reaction in the reaction zone.

A major advantage associated with the lower steam/air ratio is the drastic reduction in the conversion of fuel-bound nitrogen to ammonia (NH_3) in the gasifier. Early atmospheric gasifiers (Refs. B-6 and B-7) exhibited a strong tendency to reduce conversion of fuel-bound nitrogen into ammonia as the steam/fixed-carbon ratio dropped. This has now been verified in a pressurized gasifier (Ref. B-8), where an average of 12 percent of the fuel-bound nitrogen was converted to ammonia at a steam/air ratio of 0.245. Hence, the ammonia-scrubbing stage in the gas cleanup system is not required for the plant design to meet solid fuel emission standards.

4. The requirement of a low steam/air ratio for the advanced fixed bed gasifiers imposes certain duties on the grate design. The high-input steam rates for the standard fixed bed gasifiers had a tendency to cool the combustion zone sufficiently to prevent ash clinkering. The grates for advanced fixed bed gasifiers are required to handle weakly fusing clinkers. As discussed later, bed stirrers are provided for this purpose; this design approach allows the gasifier to handle a wide range of coals, including caking coals.

Gasifier Design. Figure B-3 shows the construction of a gasifier unit and its accessory equipment. The lump coal is fed through lockhoppers that are equipped with high-temperature ball valves. The coal fines/tar mixture is fed from two 0.25 m (10-in.)-diameter extruders (not shown) into the feed conveyor at a point directly below the lockhoppers. Coal and extrudate are fed into the top of the gasifier by a pressurized screw conveyor on each side. These screw feeders allow continuous feeding. Excess tar is injected directly into the gasifier.

The gasifier is designed in sections that can be shipped by rail. This permits factory fabrication of the sections, with its resulting economies and quality control. The gasifier pressure vessel is made up of four sections joined by bolted flanges. The bottom conical section provides support for the table and bottom stirrer. A skirt (not shown) is attached to the conical section for mounting the gasifier. The short cylindrical section directly above the conical section houses the ash and combustion (oxidation) zones of the gasifier. This section is lined with a water jacket, which keeps the pressure vessel cool and generates steam to be injected into the gasifier. The upper cylindrical section of the gasifier contains the reduction zone and the devolatilizing zone of the gasification process. This section of the gasifier is lined with a refractory insulation. The top section is a hemispherical head which provides for the gas outlet and supports the upper stirrer mechanism.

The gasifier vessel is provided with two stirrer mechanisms; both the upper and lower stirrer mechanisms are water cooled. Rotation of the bottom rabble arm is accomplished by a ring gear, and the axial motion is accomplished by a linear actuator. This motion provides for stirring of the entire ash and combustion bed. The rotational motion of the rabble arm also sweeps the ash over the edge of the table; the ash is then free to fall into the ash hopper. The axial motion of the upper stirrer is provided for by a chain drive and three screw columns. The rotational motion of the upper stirrer is provided for by a worm gear drive. The upper rabble arm is shaped to the contour of the hemispherical head so that any tar accumulation can be scraped from the outlet port, and the upper gasifier dome and offtake thus kept clear.

A moisture separator is provided at the outlet to the steam jacket. The steam is mixed with the incoming air; the water is reinjected into the steam jacket.

Gasifier Performance. The basic approach to gasifier performance prediction is a semiempirical method. Figure B-4 shows the basic four zones of the fixed bed gasifier. Coal is fed into the top of the gasifier, where moisture is driven off by the heat of the gases rising through the raw coal. As the coal progresses down through the bed it enters the

Figure B-3. Open Cycle Gas Turbine Combined—Advanced Fixed Bed Gasifier (GE)

Figure B-4. Fixed Bed Gasifier Analysis

devolatilizing zone, where the volatile matter is driven off in the form of gas. The remaining coke then enters the reduction zone, where it reacts with the hot gases from the oxidizing zone plus the steam and air blast to produce the reduction gas. The reduction gas mixes with the volatiles and moisture as it rises through the gasifier to produce the raw gas exiting from the gasifier. The remaining unreacted coke in the reaction zone proceeds down the gasifier shaft, where it is burned in the presence of the air blast to produce the heat to support the process. The ash, with a small amount of unburned carbon remaining, is discharged to the lockhopper, from which it is removed for disposal.

The semiempirical gasifier analysis proceeds as follows:

- a. Starting with the particular coal's proximate and ultimate analyses and heating value, the products of the devolatilizing and drying zones are calculated. These include H_2S , NH_3 , N_2 , CH_4 , C_2H_4 , C_2H_6 , and oils, tars, and phenols.
- b. The remaining coke is assumed to be all carbon and ash. Capacity of the gasifiers is scaled on the basis of a uniform coke-loading in pounds of coke per square foot of grate area.

- c. Products of the reduction zone and raw gas temperature are derived as a function of the ratio of pounds of steam per pound of reactive coke. The functions of the reduction gas constituents are based on reported test results from a number of sources.
- d. The air required to produce the reduction gas is calculated.
- e. The raw gas composition is the sum of products from the reduction, devolatilization, and drying zones.
- f. Lockhopper losses are assigned equally to all components of the raw gas.
- g. The moisture addition and the exit temperature from the washer cooler are then calculated.

Table B-2 lists the composition, flow rates, and pressure/temperature data for various gasifier streams. Streams 1A and 1B refer to coal feed. Stream 2 refers to the jacket water inlet conditions; the steam produced in the jacket is described by Stream 4. Stream 3A is the air extraction from the prime-cycle air compressors into which water is injected (Stream 3B), which finally forms the air blast (Stream 3) to the gasifiers. The lockhopper discharge (vent) gas is represented by Stream 5A. Stream 7 is the raw gas stream leaving the gasifier; this gas stream then passes through a washer-cooler stage in which the tar oil, naphtha, phenols, and heavy tar are separated from the gas stream and the remaining gas is saturated. Stream 8 is the saturated raw gas. The lock charge gas is taken off the washer-cooler stage.

The tar oil, naphtha, and phenols separated from the raw gas between Streams 7 and 8 eventually join the clean fuel gas stream. Only a small fraction (0.0008 kg/kg coal [lb/lb coal]) of the separated heavy tar stream becomes a blowdown flow to the incinerator; the remaining tar flow, Stream 6, is recycled to the gasifier. The heavy tar recycle is given as a range of 0.02 to 0.05 kg/kg of coal (lb/lb of coal) in order to indicate maximum possible values for the design of the gas cleanup system.

Gas Streams 7 and 8 indicate the presence of carbonyl sulfide (COS) in the fuel gas. Correlation of the data of Reference B-8 and earlier data showed that, for a pressurized gasifier, approximately 7 percent of the sulfur converts to COS and 93 percent to H_2S .

Gasifier Capacity. For a given design, gasifier capacity is a function of grate area, operating pressure, and coal composition. The capacity is basically expressed as a coke loading per square foot of grate area. Gasifier capacity for a 14-ft o.d. gasifier was estimated to be 5.75 kg/s (45,600 lb/hr) of the Illinois No. 6 coal for the gasifier operating pressure of 2420 kPa (351 psia).

Table B-2
 ADVANCED GASIFIER/CLEANUP PRELIMINARY SPECIFICATIONS
 Solid Fuel Emission Standards — All Flows in Lb/Lb Coal)

STREAM	LOCKHOPPERED COAL FEED 1/2-2 IN. 1A	EXTRUDED COAL FEED ≤ 1/8 IN. 1B	JACKET FEEDWATER 2	TOTAL AIR BLAST 3	DRY AIR BLAST 3A	WATER INJECTION 3B	JACKET STEAM 4	LOCK GAS 5A	TAR RECYCLE 6	RAW GAS TO QUENCH 7	QUENCHED GAS TO CLEAN UP 8
CO ₂								0.002387		0.2715	0.2696
CO								0.007731		0.8793	0.8733
H ₂ S								0.000338		0.0384	0.0382
COS								0.000045		0.0051	0.0051
C ₂ H ₄								0.000069		0.0079	0.0078
C ₂ H ₆								0.000104		0.0119	0.0118
CH ₄								0.000683		0.0777	0.0771
H ₂								0.000314		0.0357	0.0355
N ₂								0.011860		1.3490	1.3397
Tar oil, naphtha								0.000130		0.0688	0*
Phenols								0.000014		0.0074	0*
Heavy tar								0.000039	(0.02) (0.05)	0.0208 (0.0508)	0*
NH ₃								0.000011		0.0012	0.0012
Dry subtotal	0.6525	0.2175	0	1.7406	1.7406	0	0	0.023725	0.02 (0.05)	2.7747 (2.8047)	2.6593
H ₂ O	0.1250	0.0050	0.1960	0.1700	0	0.1700	0.1960	0.000486		0.2564	0.8145
TOTAL	0.7775	0.2225	0.1960	1.9106	1.7406	0.1700	0.1960	0.024211		3.0311 (3.0611)	3.4738
Temperature (F)	--	--	350	529	--	--	450	290		904	328
Pressure (psia)	--	--	425	360	--	--	450	--		351	343

*Nominal. There will actually be some carryover.
 Heavy tar blowdown = 0.0008 lb/lb coal.

This capacity value is conservative; it is scaled from runs made in the Bureau of Mines gasifier, which did not have a bottom stirring device. The addition of a bottom stirrer should improve throughput at the above conditions. Improved stirring can in fact permit operating at even lower steam/air ratios (approximately 0.15) where semislagging conditions will prevail. At these conditions, there is a fair probability that the gasifier capacity could be increased to 6.40 kg/s (50,800 lb/hr) of coal. However, the lower value of 5.75 kg/s (45,600 lb/hr) was used in sizing the fuel plant.

Gasification Module Design

The integrated, LBtu gasification plant will require the output of 10 gasifiers when running at full plant capacity. Figure B-5 shows the layout of a 12-gasifier plant which will permit full capacity operation with 2 gasifiers shut down for maintenance. Each bank of 6 gasifiers is fed by a high-level recirculating coal conveyor running around the periphery of its building. As needed, coal is removed from the peripheral conveyor to the individual feed hoppers for the lockhoppers and extruders. The use of side-entry screw conveyors into each gasifier reduces the overall structural height requirements, the gasifier building being approximately 30 m (100) ft high overall. Gasifier units are canted, as shown in the plan view, to permit common feed hoppers adjacent to lockhopper/extruder sets as well as to permit easy removal of gasifier vessels by crane.

Figure B-5. Gasification Module (GE)

The washer-coolers, two for each gasifier vessel, are located adjacent to the gasifier vessel. A common coal gas pipe connects these washer-coolers and carries from there raw saturated fuel gas, free of tar oils and phenols, to the gas cleanup plant.

The overall land area required for a 12-gasifier module is 38 m x 49 m (125 ft x 160 ft).

Low-Btu Gas Cleanup

The solid fuel emission standards permit discharge of 0.50 kg of SO₂ and 0.29 kg of NO₂ to the atmosphere per GJ (HHV) of solid fuel charged (1.2 lb of SO₂ and 0.7 lb of NO₂ per MBtu). With these emission limits for the plant as a whole, a relatively simple gas cleanup system is required. No ammonia removal equipment is necessary to meet NO_x emissions. Sulfur emissions can be reduced to the desired level merely by scrubbing H₂S out of the LBtu gas and converting the H₂S to elemental sulfur. No removal of COS from the LBtu gas is necessary, and no scrubbing of incinerator flues is required.

Configuration of Plant. The cleanup system is defined by the flow diagram (Figure B-6) and the general arrangement "Plan and Elevation Drawing" (Figure B-7).

The flow diagram shows the functional elements in the cleanup system. It also shows the mass and heat flows. The cleanup system consists of a gas-treating module, a sulfur recovery module, an incineration and heat recovery module, and an oil/water separation module.

The raw gas, after removal of tar, naphtha, and phenols fractions in a washer-cooler train, enters the gas cleanup system at 437 K (328 F) and 2360 kPa (343 psia), saturated with water vapor. The mass flow is 201.2818 kg/s (1,597,475 lb/hr). The gas-treating module cools the gas to 310 K (100 F), scrubs the gas to remove most of the H₂S entering with the gas, and finally reheats the gas to the required 416 K (290 F) exit temperature. This gas-treating module has been designed to provide a low pressure drop through the equipment so that the clean gas discharge pressure will be at least 2090 kPa (303 psia). The exit gas is saturated with water. The total mass flow of the gas leaving the cleanup system is 176.3304 kg/s (1,399,448 lb/hr), excluding the light oil and phenols flow.

Gas Treatment Module. The process in the gas treatment module starts with the cooling of the raw gas by heat exchanger. Bank E-204* is shown as the rightmost row of equipment in the plan view of Figure B-7, and heat exchanger bank E-205 is at the top of the second row of equipment. Both banks remove water from the gas by condensation. Heat exchanger bank E-204 cools the raw gas to 402 K (265 F) by countercurrent heat exchange with the cleaned gas

*Numbers with this format are equipment numbers corresponding to those in Table B-1 and Figure B-7.

Figure B-6. Gas Cleanup Flow Diagram (Bechtel)

B-20

Figure B-7. General Arrangement of Gas Cleanup System (Bechtel)

BECHTEL SAN FRANCISCO		
GE/EPRI ADVANCED CYCLES SYSTEMS STUDY		
GENERAL ARRANGEMENT GAS CLEAN-UP SYSTEM FOR COMBINED CYCLE WITH COAL GASIFIER		
JOB NO.	REVISION NO.	REV.
11813-001	P-1002	A

leaving the H_2S scrubber. Heat exchanger bank E-205 cools the raw gas to the final temperature of 310 K (100 F) by heat exchange with cooling water. Both banks of exchangers consist of series of stainless steel shell and tube heat exchangers with shell sections about 1.8 m (6 ft) in diameter and 6.1 m (20 ft) long. Bank E-204 contains eight shells in series. The raw gas entering the cleanup system at the top right of the plan view zigzags down through the eight shells of bank E-204. It is then piped to the top, and passes straight through the three shells (in series) of bank E-205. The gas continues downward and enters the pair of knockout drums V-302 in parallel. These drums remove residual liquid drops and particulates before the gas is allowed to enter the H_2S absorber.

The cooled gas finally moves into the two H_2S absorption towers T-304, which are in parallel at the bottom of the second row from the right in the plan view. These 2.75 m (9-ft)-diameter tray towers contain the liquid agent, with the trade name Alkazid,* that removes H_2S from the gas. Towers T-304 contain a particulate removal space at the top just before gas exit that removes almost all the solution that might otherwise be carried out as entrained droplets with the cleaned gas.

The last operation in the gas treatment module is recovery of the H_2S by regeneration of the Alkazid solution leaving the absorbers. This solution, which is enriched with H_2S , first passes into exchangers E-309 for preheating and then enters Alkazid stripping tower E-305. In this tower, an ascending flow of water vapor strips the H_2S out of the Alkazid solution so that the solution can be used again in the absorbers. The H_2S gas that is removed in the stripping tower is then passed out of the gas treatment module to the sulfur recovery module in a mixture with carbon dioxide that is called acid gas. The Alkazid plant containing the absorbing towers and stripping tower includes pumps, heat exchangers, and a number of knockout drums to remove water droplets. To operate the Alkazid H_2S stripping tower, steam must be provided to supply heat for a solution reboiler, E-310. Most of this heat is removed by cooling water in condenser E-311.

With the required amount of H_2S now removed, the cool, clean low-Btu gas next enters the tube side of heat exchanger bank E-204 (lower right of plan view of Figure B-7). As it moves straight up through the eight exchangers in series, it extracts heat from the warmer raw gas being cooled on the shell side. As the clean gas is being reheated in this way, water is added by fog nozzles upstream from the gas inlet at the top of each shell. The water then coats the inner walls of the tubes and evaporates. This water must be fairly clean, so as to avoid reintroducing substantial amounts of H_2S through the rewatering process. Thus only the

*See pages B-66 through B-72 for more detailed description of Alkazid Process.

hotter half of the foul condensate obtained from dewatering is used for rewatering. The remainder of the water for rewatering is clean condensate and boiler feedwater.

When it emerges from E-204 at the top right of the plan view, the gas is clean, reheated, and saturated. It can now leave the cleanup system.

Sulfur Recovery Module. The acid gas (H_2S and CO_2) leaving the gas treatment module is fed into the sulfur recovery module, designated PL-306. A standard Claus plant for converting H_2S to elemental sulfur, this module is shown at the left in Figure B-7. Air is used to oxidize one-third of the H_2S to form SO_2 . This gas then reacts with the remaining two-thirds of the H_2S to form a vapor of elemental sulfur. Heat is released in the oxidation reaction with the air and in the condensation of sulfur. Heat released by oxidation is used for steam generation. Heat released in sulfur condensation heats cold boiler feedwater to 422 K (300 F) so that it can be used in the gasification modules. The Claus plant converts 95 percent of the entering H_2S into elemental sulfur, which is solidified and removed from the cleanup system in powder form. The remaining 5 percent of the incoming H_2S leaves the Claus plant in the form of a tail-gas mixture of H_2S and SO_2 which has large amounts of diluent nitrogen and CO_2 .

Waste Fuel Incinerator. The tail gas is fed into the incinerator and waste heat recovery module (upper left of Figure B-7). Because the H_2S in the tail gas is toxic, it must be converted by incineration in furnace F-316 to the safer species, SO_2 , before release to the atmosphere. The incinerator burns coal-hopper leakage gas and blowdown tar that are received from the gasification complex. The heat released from this incineration is recovered in part by the generation of steam, and in part by preheating process water to 437 K (328 F) so that it can be exported as makeup water to the washer-coolers in the gasification modules.

Oil/Water Separation. The last module, the oil/water separation module, processes the mixture of oil and water received from the gasification module washer-coolers. An excess of water is provided to the washer-coolers so that the water spray will enhance the removal of hydrocarbon liquid droplets. The oil and water are separated under pressure in three vessels, V-207, shown in the lower center-right of Figure B-7. The separation uses the specific gravity difference between the hydrocarbon and water phases. Both phases are saturated with phenols. The oily phase is exported to the combustor serving the gas turbines. The water phase is recycled to the washer-coolers, along with some additional makeup water.

Additional details of the cleanup system are included under "Background Information on Low-Btu Gas Cleanup System" (pages B-66 through B-72 below).

Prime Cycle Components

The prime cycle consists of two water-cooled gas turbine units, with a 16:1 compressor pressure ratio and a firing temperature (average gas temperature at the entrance of the first rotor stage) of 1922 K (3000 F).

The design incorporates SiC ceramic combustion liners, transition pieces, and a first-stage nozzle. This material is required to withstand the gas temperatures and the radiation heat load from the high emissivity flame in the combustor. Heat radiated from the ceramic combustor shell and transition piece is blocked by a stainless steel radiation shield, which in turn is cooled by the air flow entering the combustor. Thus the casings are protected from the extreme gas temperatures. The nozzle attachments are cooled with compressor discharge air which also enters the gas path before the first-stage turbine buckets. Thus all ceramic parts cooling is considered to be "nonchargeable" to the cycle.

Turbine components from the first-stage buckets onward are water cooled. The buckets in all three stages have open-loop water-cooling in which some of the water is evaporated within the bucket cooling passages and subsequently vented to the wheel spaces for cooling and blockage. The remainder of the water, about one-third, is released at the bucket tip and recovered for cleaning and return to the feedwater system. The heat in this recovered water is used in feedwater heating.

The second- and third-stage nozzle cooling systems are closed loop. The heat is picked up only in a temperature rise of the pressurized water (no evaporation takes place). The heated water leaving the nozzles is flashed to steam for injection into the combustor for NO_x suppression, and liquid is returned to the feedwater system.

Wheel-space cooling flows are extracted from the compressor at appropriate stages and then cooled by evaporation of water in the coolant flow before injection into the wheel spaces.

The water-cooled turbine parts are maintained at surface temperatures below 811 K (1000 F), thereby substantially lessening the rate of hot corrosion. The absence of surface slots, holes, or porous transpiration cooling materials avoids any danger of the cooling systems becoming obstructed by deposits from the fuels.

The exhaust gas leaves the turbine at 1065 K (1458 F). The exhaust diffuser walls are cooled by induced-flow convective cooling over their outer surfaces resulting in maximum metal temperature around 922 K (1200 F), which permits use of 300 series stainless steel.

Performance. Table B-3 shows the fuel gas composition at the gas turbine combustor inlet. This fuel is made up of the clean gas (Stream 5) and the oil and phenol (Stream 8) of Figure B-6. These streams, treated separately in Figure B-6, are mixed before the combined stream enters the fuel gas preheater.

Table B-3
LOW-BTU FUEL COMPOSITION

CONSTITUENT	WEIGHT (%)
CO ₂	7.54
CO	28.00
H ₂ S	0.06
COS	0.16
C ₂ H ₄	0.25
C ₂ H ₆	0.38
CH ₄	2.47
H ₂	1.14
N ₂	42.95
NH ₃	0.04
H ₂ O	14.57
Tar/oil/naptha	2.20
Phenols	0.24
	100.0
LHV =	2911.0 Btu/lb (wet)
HHV =	3124.0 Btu/lb (wet)
Delivery temperature =	315 F

Table B-4 lists the cycle assumptions used in the performance evaluation. The turbine exhaust pressure drop of 27 inches of water includes the pressure losses of the exhaust duct, the HRSG unit, and the silencers. The booster compressor pressure rise allows a 48 psi pressure drop in the cleanup system and further ensures sufficient pressure margin for the fuel-gas flow control function.

Table B-4
WATER-COOLED GAS TURBINE - CYCLE ASSUMPTIONS

Ambient	- ISO (59 F, 14.70 psia, 60% relative humidity)
Compressor	- 20 stages Pressure ratio 16:1 Inlet pressure drop 4 in. H ₂ O
Combustor	- Pressure drop 3%
Turbine	- Three stages Inlet temperature 3000°F Turbine inlet Mach number 1.0 Turbine nozzle flow coefficient 1.0 Diffuser inlet Mach number 0.5 Diffuser exit Mach number 0.05 Diffuser pressure loss coefficient 0.46 Exhaust pressure drop 27 in. H ₂ O Ceramic combustor, transition piece, and Stage 1 nozzle
Booster Compressor	- Pressure ratio 1.7:1

The resulting cycle parameters are shown in Table B-5. The gas flow rate, pressure, temperature, and enthalpy values at various cycle stations are provided. For each gas turbine, the power output and the estimated losses are given below:

Gross output	=	231.23 MW	(231.23 MWe)
Electrical generator losses	=	3.00 MW	(3.00 MWe)
Net generator output	=	228.23 MW	(228.23 MWe)
Gas turbine auxiliary and other mechanical losses	=	1.16 MW	(1.16 MWe)
Net power output		227.07 MW	(227.07 MWe)

In addition, each of the two booster compressors is estimated to require 5.61 MW of shaft power.

Turbine Design. A cross-section view of the gas turbine-compressor-combustor unit is shown in Figure B-8. The compressor has 20 stages, with the inlet guide vane and first four stator stages variable. The combustor has 12 can-type burners. The turbine has three stages. The gas turbine exhaust is axial, which allows for a better layout of the HRSG unit which follows it. The third bearing, located in the turbine exhaust area, is shielded from the exhaust gases.

Table B-5
CYCLE OPERATING PARAMETERS

PARAMETER	FLOW (lb/s)	PRESSURE (psia)	TEMPERATURE (F)	ENTHALPY* (Btu/lb)
Compressor Inlet	700.00	14.55	59.0	125.27
Air to combustor	565.87	232.84	760.8	298.91
Process Air	111.17	232.84	760.8	
Water injected into process air	10.86	258.00	108.0	
Booster compressor inlet	122.03	221.20	341.1	207.61
Gasifier inlet	122.03	374.68	506.3	251.44
Clean fuel gas at saturator exit	199.23	302.69	290	
Fuel gas at combustor interface	199.23	275.50	315	218.18
Gas turbine exhaust	800.79	15.49	1457.6	529.35
Temperature/enthalpy data for exhaust gas			1214.4	454.40
			716.6	308.31
			300.0	193.93
Water injection in cooling air	1.04	100	57	
	0.14	50	57	
Nozzle coolant supply	49.87	1500	257	
Nozzle coolant return	49.87	1250	512.4	
Bucket coolant supply	20.22	250	100	
Bucket coolant return	6.88			296.63
*Enthalpy values for the gases are references to 0°R				

Because of the axial turbine exhaust arrangement, the generator is connected to the main shaft on the compressor side. The gasifier process air is extracted from the compressor discharge through 0.10 m (4 in.)-diameter pipes.

The construction of the water-cooled turbine nozzles essentially consists of a cast-iron-base alloy core surrounded by Monel water-cooling tubes embedded in a copper layer, which is clad with a corrosion-resistant outer skin. The copper layer aids in distributing the heat to the cooling tubes. The water-cooled bucket construction is similar except that the water flow is metered so as to fill each tube only partially, allowing evaporation to enhance the cooling effectiveness.

Bottoming Cycle Components

The steam bottoming cycle has two identical HRSG units and a reheat steam turbine-generator unit. The feedwater heating system, including the gas turbine bucket and nozzle cooling loops, is also discussed here.

Figure B-8. Water-Cooled Gas Turbine (GE)

Heat Recovery Steam Generator (HRSG)

The HRSG unit consists of the following heat exchanger sections:

Superheater	}	One per unit
Reheater		
Evaporator	}	Two per unit (one each per tower)
Economizer		

One HRSG unit is provided for each gas turbine. Since the gas turbine exhaust flow is axial and the exhaust temperature is high, the reheater/superheater section of the HRSG is located in a horizontal duct section close to the gas turbine exhaust diffuser to minimize hot-gas ducting problems. The gas leaving the horizontal section is supplied to two parallel vertical towers, through which the gas passes over the evaporator and the economizer. A high-pressure steam drum serves both towers.

The HRSG unit is unfired; that is, fuel combustion does not occur in the HRSG. However, to allow for gas turbine startup on auxiliary fuel and for possible deposition of ash from semiclean fuel combustion gas, sootblowers are provided in the HRSG unit.

Performance. For a steam cycle with a reheat steam turbine unit, the performance evaluation is an iterative procedure between the HRSG and the steam turbine because the steam flow rate through the reheater section of an HRSG is less than the flow through the economizer evaporator-superheater sections. In this application, this is due to the following:

- The steam leakage flows from the valve stem, and the packings are estimated only after the steam turbine configuration is selected to satisfy cycle requirements.
- In addition, in this case, the steam supply for the booster-compressor drive turbine is extracted from the cold reheat point (that is, after the throttle steam has expanded through the high-pressure turbine section).

The final performance parameters are summarized in Table B-6. The steam cycle data indicate that combustion gases leave the economizer section at 445 K (342 F).

As mentioned in "Cycle Description," a fraction of the combustion gases leaving the economizer unit is supplied to the coal dryer; when this flow is returned and mixed with the remaining gas, the final stack temperature of 422 K (300 F) results.

Steam Turbine-Generator

For the steam cycle conditions and flow rates given in Table B-6, a single reheat steam turbine with a flow capacity to serve both HRSG units is used. This steam turbine, designated

Table B-6
STEAM CYCLE PERFORMANCE PARAMETERS
FOR HEAT RECOVERY STEAM GENERATOR

STEAM SIDE				
STREAM	PSIA	TEMPERATURE (F)	ENTHALPY (Btu/lb)	FLOW (Mlb/hr)
Feedwater (in.)	2704	262	230.5	0.659
Throttle steam	2544	1005	1460.4	0.659
Cold reheat steam	520	615	1306.9	0.575
Reheat return steam	468	1000	1521.3	0.575
Drum conditions: 2682 p, 678 F				
GAS SIDE				
HEAT EXCHANGER	TEMPERATURE In (F)		TEMPERATURE Out (F)	
Reheater	1458		1319	
Superheater	1319		1020	
Evaporator	1020		749	
Economizer	749		342	
Note: All flows are per HRSG unit				
Basis: Gas Turbine Exhaust Flow = 2.88 Mlb/hr				
Exhaust Temperature = 1458 F				

4 x 16.5 LSB, consists of one high-pressure section, one intermediate-pressure section, and four low-pressure sections (two double-flow sections) with last-stage bucket height of 0.419 m (16.5 in.). All turbine sections are on the same shaft, to which the generator is also connected.

Performance. The steam flows required for various plant duties are indicated on the cycle schematic (Figure B-2). The steam flows extracted from the steam turbine unit are discussed below:

1. For Booster Drive Turbine. This steam is extracted from the cold reheat point, at 3580 kPa (520 psi), 597 K (615 F), and 3039.6 kJ/kg (1306.8 Btu/lb). The total steam flow requirement is estimated to be 15.0911 kg/s (119,771 lb/hr).
2. For Cleanup Process. As mentioned in "Cycle Description," the saturated process steam requirements at 450 kPa (65 psi) are met from various sources; the external process steam demand of 12.346 kg/s (97,985 lb/hr) is satisfied by extracting 1.132 kg/s (8987 lb/hr) of 540 kPa (79 psia) steam from the steam turbine,

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Materials of Construction

The proposed materials of construction for the water-cooled gas turbine and for the advanced fixed bed gasifier are reviewed here, with a brief critique on the design philosophy.

Gas Turbine. The extremely high gas temperature of 1922 K (3000 F) requires highly efficient cooling for metal parts or the use of ceramics. It is proposed to use a silicon carbide (SiC) ceramic for the combustor can, transition piece, and first-stage nozzle; and a composite water-cooled construction for the buckets and the second- and third-stage nozzles. The alloys proposed for the major components are listed in Table B-7.

Table B-7
MATERIALS FOR WATER-COOLED GAS TURBINE

COMPONENT	SUBCOMPONENT	MATERIAL	COMMENTS
Compressor	Casing	Modular Iron	
	Vanes	403 Stainless Steel	
	Rotor disk	A4340	
	Blades	403 Stainless Steel	
Combustor	Cans & Flow shield	SiC	
	Casing	Modular iron or 2 1/4 Cr-1 Mo	
Turbine	Transition piece	SiC	A286 is used for the core, IN-671 for the outer skin and a copper alloy for the inner skin.
	Nozzle 1st Stage	SiC	
	2nd and 3rd Stages	A286	
	Interstage diaphragm	HN Stainless Steel	
	Interstage seal	IN-718	
	Shell	Modular iron	A286 is used for the core, IN-671 for the outer skin, and a copper alloy for the inner skin.
	Rotor front shaft	IN-706	
	Buckets	A286	
	Disk	IN-706	
	Spacer	IN-706	
	Rear shaft	IN-706	
	Tie bolts	IN-718	
	Cooling fan blade	403 Stainless Steel	
	Cooling fan disk	A4340	
	Exhaust casing liner	LC steel	
	Cooling fan flow guide	321 or 347 Stainless Steel	
	Tie bolts	304 Stainless Steel	
		IN-718	

Design Philosophy. Detailed designs have not yet been developed. However, the philosophy will be similar to that used successfully for metallic parts for industrial air-cooled gas turbines. The designs incorporate creep, rupture, crack initiation, and crack propagation resistance in both high-cycle and low-cycle fatigue and corrosion, and oxidation resistance. In addition, it will be necessary to consider the mechanical response of the composite buckets with a steep temperature gradient and dissimilar materials. The SiC parts will incorporate the statistical nature of fracture in ceramics, since the average strength is dependent on both the specimen size and the loading configuration.

To minimize hot corrosion and erosion, specifications consistent with the design for the fixed bed gasifier have been used for maximum carryover of contaminants. These specifications are:

<u>Impurity</u>	<u>PPM in Combustion Product</u>
Na + K	< 0.020
Pb	< 0.020
V	< 0.010
Ca	< 0.040
S	< 0.005
Solids	< 0.010
All others	< 30

The design lives for the major components in thousands of hours, assuming 1 start per 1000 hours, are given below:

Combustion liner and crossfire tubes	25
Transition pieces	25
Nozzles	25
Buckets	50
Shrouds	100
Wheels	240
Casings, frames	240

In addition, it is assumed that some accessory items may be replaced or repaired after 25,000 hours.

Materials Critique. The hot-gas parts are critical in the construction and operation of the water-cooled turbine. There is no service experience with SiC for nozzles, and the problems of fabrication in the requisite size, thermal shock capability, surface stability, and attachment have been assumed to be amenable to solution during a development program. Such studies are just beginning (Ref. B-9), and definitive assessment cannot yet be made. Thermal fatigue tests of tapered disks in a fluidized bed and tapered wedges in a simulated engine test have given some failures in the former test when the disks were cooled from 1193 K (1688 F). The estimated maximum hoop stress during the cooling shock was 255 MPa (37,000 psi). With improvements in processing and machining, some improvement in thermal fatigue resistance can be expected. Whether the fatigue resistance can be improved to the point of acceptable probability of failure in a large nozzle subjected to a cooling shock from 1922 K (3000 F) remains a primary concern.

The fabrication of composite buckets and second- and third-stage nozzles will present a major challenge. One possibility is that the stainless steel tubes which will carry the water will be surrounded by copper-dispersion-strengthened alloy powder, the whole being embedded in an A286 core. The corrosion-resistant IN-671 is added as a cladding, and the entire composite is hot isostatically pressed.

The long-time operating reliability of a composite bucket hinges on several factors. The creep behavior of the bucket in a steep temperature gradient is unknown. For the water-cooled buckets and nozzles, questions regarding the cooling effectiveness as well as the erosion of channels and of the jet impingement area are not yet resolved.

The later stages are expected to require large buckets of the order of 0.60 to 0.66 m (24 to 26 in.) which will generate high dovetail stresses. It may be necessary to fabricate these buckets from powder to achieve the necessary yield strength. This would then present new challenges for the introduction of cooling passages.

Advanced Fixed Bed Gasifiers. The fixed bed gasifier presents some materials problems. However, since the reaction zone is limited and contained in the refractory, metal temperatures are generally kept quite low so that corrosion is unlikely to be of concern if the brickwork is properly mounted. Most of the gasifier is made of carbon steel, with some surface hardening or hard facing with stellite in critical locations where abrasion and wear problems might occur. Lockhopper seals, stirrer shaft seals, and the screw processing mixes of coal, ash and tar are obvious sites. Some erosion of the grate and stirrer may also be encountered. In addition, there may be problems of carbon buildup or fouling on the walls of the vessel.

Summary of Materials Considerations. A considerable amount of development work is required for the major components. Technical innovations are required in fabrication of composite buckets, and technical barriers such as erosion or corrosion may be encountered with more exploratory work. The potential corrosion problem could extend to the exhaust duct of the HRSG, which operates at 1066 K (1458 F).

The severity of hot corrosion will depend on the level of contaminants in the gas, but the lower metal temperature of the water-cooled turbine buckets and nozzles greatly minimize the potential for hot corrosion. Metal wear will be an important consideration in the stirrer and breaker parts required in the fixed bed gasifier.

BALANCE-OF-PLANT ARRANGEMENT AND COSTS

The plant arrangement drawings, showing the power plant equipment arrangement and the provision for on-site fuel and waste storage, are prepared for a Middletown, U.S.A., plant site, with the plant situated just south of the North River.

Plot Plan

Figure B-10 shows the plant area, which is surrounded by a perimeter road and has a 60-day dead storage coal pile and 3-day live storage capacity. Storage facilities are provided for 15-day storage of ash discharged from the gasification module and sulfur generated from the Claus plant. The LBtu fuel plant and the power generation area are located adjacent to each other. Other plant support facilities, the switchyard and the cooling towers, are also situated in the plant area.

Coal Handling and Storage. The compacted dead storage pile is 18.3 m (60 ft) high with a base measuring about 299 x 128 m (980 x 420 ft). This stores 220.132 Mkg (242,650 tons) of coal for recovery by use of dozer tractors. Two conical live storage piles are provided with a base diameter of about 88.5 m (290 ft). These piles contain a total of 80.251 Mkg (88,460 tons) of coal, with 20.621 Mkg (22,730 tons) available by gravity feed through under-pile vibrating feeders to a conveyor belt that lifts the coal to feed hoppers. The hoppers supply coal to the coal dryer and then to the crusher; the crushed, overscreened coal and the underscreened fines are supplied to two gasification modules by parallel conveyors at an average combined feed rate of 58.0 kg/s (230 tons/hr).

LBtu Fuel Plant. The fuel plant consists of a gasification module and a gas cleanup system. The gasification module has two rows of 6 gasifier vessels each. The cleanup system includes a series of heat exchangers to cool the raw gas and reheat the clean gas, an Alkazid plant to remove H_2S from the raw gas, a Claus plant to convert H_2S to elemental sulfur, and an incinerator. The gasifier vessel arrangement details are given in Figure B-5, and the cleanup system details are presented in Figures B-6 and B-7.

Power Generation Area. This area includes two gas turbines, each connected to an HRSG, as shown in Figure B-11. The steam turbine building includes a reheat steam turbine, a steam condenser and associated feedwater heaters, and pumps. The arrangement provides two separate and parallel turbine gas flow paths, permitting independent operation of each gas turbine.

Figure B-10. Plot Plan for Open Cycle Gas Turbine Combined--Water Cooled--LBtu Gasifier (GE)

Figure B-11. General Arrangement Plan for Open Cycle Gas Turbine Combined--Water Cooled--LBtu Gasifier (GE)

GENERAL ELECTRIC	
PROJECTS ENGINEERING OPERATION	
INSTALLATION AND SERVICE ENGINEERING DEPT.	
DATE	PROJECT NO.
1-20-01	XII-75F-MQ1
REV.	0

Solid Wastes Handling. Ash from the gasification modules and dry sulfur from the Claus plants of the gas cleanup process are the solid waste products for this plant. Ash is produced at a nominal rate of 5.59 kg/s (22.2 tons/hr), which is conveyed to loading silos at the rail spur. A standby ash storage capacity of 7.212 Mkg (7950 tons) is provided by two storage silos. Sulfur is produced at a nominal rate of 1.89 kg/s (7.5 tons/hr). This is also conveyed to a loading silo at the rail spur. Standby dry-sulfur storage capacity of 2.45 Mkg (2700 tons) is provided for in one storage silo.

Cooling Towers. For this plant, with a heat rejection load of 415.99 MJ/s (1419.5 MBtu/hr), eight cooling tower cells and a water circulating capacity of 6.624 m³/s (105,000 gpm) were used.

Ponds. The surge pond and the wastewater pond have been sized for 3 day and 12 hour capacities, respectively.

The land requirements for this plant are:

Plant land (including coal storage)	= 242,760 m ² (60 Acres)
Ponds	= 72,828 m ² (18 Acres)
Total	= 315,588 m ² (78 Acres)

Plan and Elevation Views of Power Plant Area

Figure B-11 shows the ground floor plan of the turbine buildings, indicating the arrangement of the gas turbine/HRSG units with respect to the steam turbine condenser unit. The horizontal duct of the HRSG, containing the reheater and superheater heat exchangers, is located as close as possible to the gas turbine to minimize hot gas duct length. The gas turbine is provided with a starting motor. For each gas turbine unit, auxiliary equipment—such as lubricating oil coolers, demister, CO₂ skid, and accessory skid—is provided. Lay-down area is provided for ease of maintenance of gas turbine units. The HRSG units are situated so that a common tube pull space would be utilized for both units.

The ground floor view of the steam turbine building shows the steam condenser located beneath the low-pressure section of the steam turbine. The plan view at 9.2 m (30 ft) elevation shows the steam turbine and the deaerator tank.

The elevation view, Sections A and C of Figure B-12, indicates the turbine building in relation to gas turbine/HRSG units. Overhead cranes are provided, one in each gas turbine building and one at the turbine floor of the steam turbine building. The silencers are located at the

Figure B-12. General Arrangement Elevation for Open Cycle Gas Turbine Combined--Water Cooled-- LBtu Gasifier (GE)

top of the HRSG towers, and stacks are provided on top of the silencers, for a total stack height of 27.2 m (90 ft).

The view in Section B indicates the inlet filter and silencer arrangement for the compressor inlet air duct. Note that a section of the duct is removable to allow access to the overhead crane.

One-Line Electrical Diagram

The plant electric system can be functionally divided into two major interdependent systems: the system supplying power to the 500 kV transmission system, and the system supplying power to the plant auxiliaries. These systems are described in Figure B-13.

Each gas turbine generator is connected by isolated phase bus duct to one of two three-winding power transformers where the 25 kV generator voltage is increased to the 500 kV transmission voltage. The steam turbine generator is similarly connected to grid through a two-winding stepup power transformer. Thus each of the three generators has its own power transformer. Isolation and protection devices are provided in the delivery system as required.

Power is distributed to plant auxiliaries through two 13.8 kV auxiliary buses. During normal operation, each auxiliary bus receives power from a 13.8 kV third winding on a gas turbine transformer; one gas turbine transformer and one auxiliary bus make up one of two independent auxiliary power systems. The steam turbine generator does not normally supply power for auxiliaries.

The 13.8 kV auxiliary buses are suitably isolated, thereby minimizing short circuit currents in case of a fault in either of the auxiliary buses or a power source.

The 13.8 kV auxiliary bus voltage is stepped down as required to suit the load. The large power consumers, such as electric motors 186 kW (250 hp) or larger, are supplied through the 4160 volt switchgear. Smaller consumers are supplied from 460 volt load centers and the motor control centers.

Each 13.8 kV auxiliary bus is protected against loss of power during normal operation by an automatic bus transfer system. If the system supplying power from a gas turbine transformer fails, the automatic bus transfer system actuates the appropriate breakers to supply power to the auxiliary bus from the startup system. The automatic transfer system includes relays as required to assure correct breaker operation.

Figure B-13. Electrical Diagram for Open Cycle Gas Turbine
Combined--Water Cooled--LBtu Gasifier

Normal plant startup is accomplished with power from grid by using the startup transformer to step-down the 500 kV transmission voltage to the 13.8 kV auxiliary bus voltage. The gas turbines are started, one at a time, by supplying power selectively to the bus associated with the auxiliaries of the turbine being started. After one gas turbine is at rated speed and synchronized, the startup system is isolated and power is supplied to the auxiliary bus from a gas turbine main transformer. The second gas turbine is started by a similar sequence. The steam plant is started by the use of power from the 13.8 kV auxiliary buses, as in normal operation.

If a black start becomes necessary, the on-site diesel generator can be used to start one gas turbine by means of the 480 V critical item bus system. After the gas turbine attains rated speed, the second gas turbine can be started normally using the startup system.

The electric system includes panelboards, switches, power and control cable, conduit, bushings, cable trays, wireways, junction and terminal boxes, cable accessories and ground systems. All electrical installation materials provided are of a quality normally utilized for power plant service. Various devices such as pushbuttons, auxiliary relays, and other control equipment are included where needed to assure safe and efficient system operation.

Capital Costs—Balance of Plant

The following tables provide a detailed breakdown of the direct manual field labor in thousands of man-hours and of balance-of-plant (BOP) materials cost in thousands of dollars for each major BOP category.

Table B-8 gives BOP capital costs for the entire plant, excepting the gasification module; Table B-9 gives BOP capital costs for the gasification module. The information in both tables refers to the plant designed to meet solid fuel emission standards.

In Table B-8, Section A presents an estimate summary for the eight categories of field skills as generally used by an architect-engineer. Similarly, Section A of Table B-9 lists in similar categories the costs associated with the gasification module. Section B of each table provides additional definition of the detailed estimates.

In each case, the field labor is allocated an average hourly rate of \$11.75 in mid-1975 dollars.

Table B-8

BALANCE-OF-PLANT CAPITAL COSTS
OPEN CYCLE GAS TURBINE COMBINED CYCLE-WATER COOLED
(Except Gasification Module)

A. SUMMARY	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)	TOTAL (\$1000s)
1.0 Steam Generators	130	460	
2.0 Turbine Generators	89	158	
3.0 Process Mechanical Equipment	184	14,102	
4.0 Electrical	660	10,701	
5.0 Civil and Structural	571	7,808	
6.0 Process Piping and Instrumentation	489	5,954	
7.0 Yardwork and Miscellaneous	135	2,000	
8.0 Gasification Cleanup System	<u>562</u>	<u>17,790</u>	
Direct Labor @ \$11.75	2,820	58,973	58,973
Direct Field Cost			<u>33,135</u>
			92,108
B. COST ESTIMATE DETAIL	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)	
1.0 Heat Recovery Steam Generators			
Erect only (supply by others): Includes economizer; evaporator; superheater; reheater; steam drum; stack closure duct; stack transition duct; elbow duct; tee duct; diffuser duct; filler duct; insulation for above; silencers	102		
Supply and erect: Includes support steel and access steel for above; miscellaneous materials; labor operations	28	460	
	<u>130</u>	<u>460</u>	

Table B-8 (Cont'd)

B. COST ESTIMATE DETAIL (CONT'D)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
2.0 Turbine Generators		
2.1 Steam turbine generator	45	35
Erect only (supply by others): Includes 215 MWe steam turbine; generator; exciter; auxiliary equipment; integral steam and auxiliary piping; insulation; miscellaneous labor operations		
2.2 Gas turbine generators	44	123
Erect only (supply by others): Includes two 228 MWe, water- cooled gas turbine generators; auxiliary equipment; integral fuel and coolant piping; insu- lation; miscellaneous labor operations		
	<u>89</u>	<u>158</u>
3.0 Process Mechanical Equipment		
3.1 Boiler feedwater pumps	2	604
Supply and install: Includes motor-driven main feedwater pumps and drivers (2@ \$292,000 each)		
3.2 Main circ. water pumps	3	300
Supply and install: Includes main circ. water pumps and motors (3 @ \$113,000 each)		
3.3 Other pumps	1	130
Supply and install: Includes main condensate pumps and motors (2 @ \$11,000 each); booster turbine condensate pumps and motors; saturator spray pumps and motors; other pumps and drivers not listed elsewhere		

Table B-8 (Cont'd)

B. COST ESTIMATE DETAIL (CONT'D)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
3.4 Gas turbine coolant pumps Supply and install: Includes bucket coolant pumps and motor (2 @ \$10,000 each); nozzle coolant pumps and motors (2 @ \$105,000 each)	1	230
3.5 Main Condenser Supply and install: Includes shells; tubes; air ejectors	12	679
3.6 Heaters, exchangers, tanks, and vessels Supply and install: Includes booster turbine condenser; deaerating heater and storage tank; flash tank; desuperheater; fuel gas pre- heater; saturator; all heaters, exchangers, tanks, and vessels not listed elsewhere	5	1,113
3.7 Stacks Supply and erect: Includes two exhaust stacks per gas turbine	2	116
3.8 Turbine hall cranes Supply and erect: Includes one crane and accessories for steam turbine hall and one for gas turbine hall	2	380
3.9 Booster air compressor Supply and install: Includes compressor with steam turbine driver and all auxiliaries	7	1,280

Table B-8 (Cont'd)

B. COST ESTIMATE DETAIL (CONT'D)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
3.10 Coal handling Supply and erect: Includes railcar dumping equipment; dust collectors; primary crushing equipment; belt scale; sampling station; magnetic cleaners; mobile equipment; conveyors to pile; reclaiming feeders; conveyors to cascade; coal cascade	61	4,720
3.11 Ash handling Supply and erect: Includes conveyors within gasification module; ash storage silos with founda- tions, feeders, and unload- ers; railcar loading equip- ment	27	1,380
3.12 Sulfur handling Supply and erect: Includes covered conveyors from gas cleanup plant; sul- fur storage silos with foun- dation, feeders, and un- loader; railcar loading equipment	9	450
3.13 Cooling towers Supply and erect: Includes mechanical draft towers with fans and motors	20	900
3.14 Other mechanical equipment Supply and install: Includes water treatment and chemical injection; instru- ment air compressors and aux- iliaries; fuel oil ignition and warmup; screenwell, mis- cellaneous plant equipment; equipment insulation	32	1,820
	<u>184</u>	<u>14,102</u>

Table B-8 (Cont'd)

B. COST ESTIMATE DETAIL (CONT'D)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
<p>4.0 Electrical</p> <p>4.1 Main transformers Includes main power trans- formers</p> <p>4.2 Other transformers and main bus Includes startup transformer; station service transformers; generator main bus</p> <p>4.3 Switchgear and control centers Includes switchgear and load centers; motor control cen- ters; local control stations; distribution panels, relay, and meter boards</p> <p>4.4 Other electrical equipment Includes communications, grounding; cathodic and freeze protection; lighting; preoper- ational testing</p> <p>4.5 Auxiliary diesel generator Includes diesel generator, batteries, and associated dc equipment</p> <p>4.6 Conduit, cable trays, wire, and cable</p>	<p>8</p> <p>21</p> <p>28</p> <p>226</p> <p>2</p> <p>375 660</p>	<p>2,985</p> <p>1,350</p> <p>2,656</p> <p>1,200</p> <p>110</p> <p>2,400 10,701</p>
<p>5.0 Civil and Structural</p> <p>5.1 Concrete substructures and foundations Includes turbine building sub- structures; coal, sulfur, and ash handling foundations, pits, and tunnels; miscella- neous equipment foundations; auxiliary building substruc- tures; miscellaneous concrete</p>	<p>240</p>	<p>2,000</p>

Table B-8 (Cont'd)

B. COST ESTIMATE DETAIL (CONT'D)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
5.2 Superstructures Includes turbine buildings; auxiliary yard buildings	176	4,698
5.3 Earthwork Includes building excavations; coal, sulfur, and ash handling excavations; circ. water system excavations; miscellaneous foundation excavations; de- watering and piling	110	290
5.4 Cooling tower basin and circ. water system Includes circ. water pump pads, riser, and concrete envelope for pipe; cooling tower basin; circ. water pipe; cooling tower miscellaneous steel and fire protection	45	820
	<u>571</u>	<u>7,808</u>
6.0 Process Piping and Instrumentation		
6.1 Steam and feedwater piping Includes main steam; extraction steam; hot reheat; cold reheat; feedwater and condensate large piping, valves, and fittings	25	1,080
6.2 Fuel-gas large pipe	4	160
6.3 Turbine bucket and nozzle coolant; NO _x control large pipe	3	25
6.4 Other large piping Includes auxiliary steam; process water; auxiliary systems; compressor bleed; steam-air injection	100	1,530

Table B-8 (Cont'd)

B. COST ESTIMATE DETAIL (CONT'D)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
6.5 Small piping Includes all piping, valves, and fittings of 2 in. diameter and less	78	695
6.6 Hangers and misc. labor opera- tions Includes all hangers and sup- ports; material handling; scaffolding; misc. labor opera- tions	182	624
6.7 Pipe insulation	32	340
6.8 Instrumentation and controls	65	1,500
	<u>489</u>	<u>5,954</u>
7.0 Yardwork and Miscellaneous		
7.1 Site preparation and improve- ments Includes soil testing; clear- ing and grubbing; rough grad- ing; finish grading; landscap- ing	32	10
7.2 Site utilities Includes storm and sanitary sewers; nonprocess service water	5	50
7.3 Roads and railroads Includes railroad spurs; roads, walks, and parking areas	37	1,040
7.4 Yard fire protection, fences and gates	52	600
7.5 Water treatment ponds Includes earthwork; lining; offsite pipeline	8	20
7.6 Laboratory, machine shop, and office equipment	1	280
	<u>135</u>	<u>2,000</u>

Table B-8 (Cont'd)

B. COST ESTIMATE DETAIL (CONT'D)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
8.0 Gasification Cleanup System		
8.1 Pumps and drivers	20	400
Supply and install: Includes gasifier boiler feed pump; other pumps and drives; bulk material; miscellaneous labor operations		
8.2 Heater and exchangers	400	8,820
Supply and install: Includes heaters and exchang- ers; bulk material; miscella- neous labor operations		
8.3 Tanks and vessels	45	870
Supply and install: Includes tanks, vessels, and towers; bulk material; mis- cellaneous labor operations		
8.4 Claus plant	97	7,700
	<u>562</u>	<u>17,790</u>

Table B-9
BALANCE-OF-PLANT CAPITAL COSTS
GASIFICATION MODULE

A. SUMMARY	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)	TOTAL (\$1000s)
3.0 Process Mechanical Equipment	17	1,844	
4.0 Electrical	27	584	
5.0 Civil and Structural	34	933	
6.0 Process Piping and Instrumentation	48	740	
9.0 Gasification Module	<u>168</u>	<u>507</u>	
Direct Labor @ \$11.75	294	4,608	4,608
Direct Field Cost			<u>3,454</u>
			8,062
B. BALANCE-OF-PLANT ESTIMATE DETAIL	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)	
3.0 Process Mechanical Equipment			
3.7 Gasifier building cranes	3	120	
Supply and erect: Includes two cranes for gasification module			
3.9 Coal handling	12	1,656	
Supply and erect: Includes coal dryer, secondary crusher, screens, gasification module conveyors, coal fines-tar handling, and mixers			
3.10 Ash handling	2	68	
Supply and erect: Covered conveyors from the gasification module			
	<u>17</u>	<u>1,844</u>	

Table B-9 (Cont'd)

B. BALANCE-OF-PLANT ESTIMATE DETAIL (Cont'd)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
4.0 Electrical 4.2 Other transformers and main bus Includes auxiliary trans- formers 500 KVA 4.3 Switchgear and control centers Includes switchgear, motor control centers, distri- bution panels 4.4 Other electrical equipment Includes grounding and lighting 4.6 Conduit, wire, and cable	 1 2 9 15 27	 122 181 101 180 584
5.0 Civil and Structural 5.1 Concrete substructures and foundations Includes gasifier foundations 5.2 Superstructures Includes gasification module buildings	 13 21 34	 94 839 933
6.0 Process Piping and Insentation 6.4 Other large piping Includes fuel gas supply 6.5 Small pipe Includes all piping, valves, and fittings of 2 in. diameter and less	 34 4	 568 48

Table B-9 (Cont'd)

B. BALANCE-OF-PLANT ESTIMATE DETAIL (Cont'd)	DIRECT MANUAL FIELD LABOR (MH 1000s)	BALANCE-OF- PLANT MATERIAL (\$1000s)
6.6 Hangers and misc. labor operations	8	99
Includes all hangers and supports, material handling, scaffolding, misc. labor operations		
6.7 Pipe insulation	<u>2</u>	<u>25</u>
9.0 Gasification Module	<u>48</u>	<u>740</u>
9.1 Gasifiers Supply and install: Includes pressure vessel, stirrer mechanisms, lock hoppers and valves, ex- truders, separator (12 @ \$1,859,000)	164	(22,310)*
9.2 Wash coolers Supply and install: Includes tanks, nozzles, piping (24 @ \$14,875)	2	357
9.3 Coal hoppers Supply and install: Includes holding hoppers within gasification module	2	150
	<u>168</u>	<u>507</u>

*Coal gasifier to be considered under major equipment.

Balance-of-Plant Equipment Lists

Specifications for the balance-of-plant equipment are listed in the following categories:

- Table B-10 lists equipment for the complete plant, including the gasification system but excluding the cleanup system.
- Table B-11 is the gas cleanup system equipment list.

This equipment, together with the major cycle components, makes up the combined cycle plant burning LBTu gas, designed to meet solid fuel emission specifications.

The capacity of the coal- and fuel-handling equipment and the capacity of the fuel cleanup equipment are based on handling a coal flow of 62.37 kg/s (247.5 tons/hr); the final cycle performance resulted in a coal flow of 57.93 kg/s (229.9 tons/hr), thus providing a margin of approximately 8 percent in the coal handling capacity.

In general, the installed capacities (flow and developed head) of the BOP components include margins over the estimated design duties. Thus, when the cycle performance is evaluated for a "normal" day, the installed power rating of the auxiliary cycle component is adjusted to reflect "design" duties.

CYCLE PERFORMANCE AND COST

This subsection presents data on electrical power output and plant auxiliary power demand estimates. It also contains a summary of capital cost and BOP materials and field labor cost data for the entire plant. These cost data are based on the detailed BOP costs presented above under "Capital Costs—Balance of Plant."

Table B-12 summarizes the system electrical output. Note that the ratio of prime cycle output to bottoming cycle output is 2:1. The total plant auxiliary electrical power loss is 3.8 percent; the basis for the auxiliary loss estimation is given in Table B-13. Here, maximum electrical loads for circuit capacity requirements are given as "Rated MWe," and the nominal average continuous operating power consumption is indicated as "Total MWe."

Table B-14 provides cost data for major cycle components. Note that the total installed cost data in Table B-14 include the major components only and do not include substantial costs associated with other BOP components, while the installed cost data in Table B-15 include all associated costs. Table B-15 presents plant capital cost breakdown in various categories. Note that the steam generator capital cost in Table B-15 includes the cost of silencers for the HRSG units. The plant cost, including the component capital cost, direct and indirect labor and balance-of-plant materials cost, is estimated at \$212.92 million. The total estimated

Table B-10
BALANCE-OF-PLANT EQUIPMENT LIST
OPEN CYCLE GAS TURBINE COMBINED--WATER COOLED

ITEM	DESCRIPTION
<u>1.0 Coal and Ash Handling Systems</u>	
Coal Receiving Conveyor Belt	60 in. wide, 340 ft long, 3000 t/h, 375 hp
Coal Receiving Conveyor Belt	60 in. wide, 685 ft long, 3000 t/h, 700 hp
Coal Cascade Supply Conveyor Belt	42 in. wide, 960 ft long, 500 t/h, 150 hp
Coal Cascade Supply Conveyor Belt	42 in. wide, 600 ft long, 500 t/h, 115 hp
Gasification Module Supply Conveyor Belt	30 in. wide, 250 ft long, 250 t/h, 30 hp
Gasification Module Supply Conveyor Belt	18 in. wide, 220 ft long, 125 t/h, 10 hp
Gasification Module Supply Conveyor Belt (2 required)	18 in. wide, 120 ft long, 60 t/h, 5 hp
Gasifier Supply Conveyor Belt (2 required)	30 in. wide, 360 ft long, 250 t/h, complete with motors and discharge chutes
Gasification Module Ash Conveyor Belt	18 in. wide, 400 ft long, 20 t/h, motors included
Ash Conveyor Belt	24 in. wide, 1720 ft long, 24 t/h
Ash Conveyor Belt (2 required)	24 in. wide, 50 ft long, 24 t/h
Ash Conveyor Belt (2 required)	36 in. wide, 40 ft long, 150 t/h
Ash Conveyor Belt	36 in. wide, 170 ft long, 150 t/h
Fines-Tar Mixture Screw Conveyor (4 required)	12 in. dia, 140 ft long, 25 t/h, 10 hp
Fines-Tar Mixture Screw Conveyor (2 required)	12 in. dia., 50 ft long, 25 t/h, 10 hp
Fines-Tar Mixture Screw Conveyor (24 required)	6 in. dia., 8 ft long, 3 t/h, 1/2 hp
Sulfur Conveyor Belt	14 in. wide, 160 ft long, 10 t/h
Sulfur Conveyor Belt	14 in. wide, 560 ft long, 10 t/h
Sulfur Conveyor Belt	14 in. wide, 1560 ft long, 10 t/h
Sulfur Conveyor Belt	14 in. wide, 70 ft long, 10 t/h
Sulfur Conveyor Belt	14 in. wide, 340 ft long, 150 t/h
Sulfur Conveyor Belt	14 in. wide, 60 ft long, 150 t/h
Dryer (1 required)	Cyclone dryer with fan, HRSG exhaust, gas heat, 250 t/h coal
Crusher (1 required)	Reversible Hammermill with 25% fines, 250 t/h

Table B-10 (Cont'd)

ITEM	DESCRIPTION
<u>1.0 Coal and Ash Handling Systems (Cont'd)</u>	
Screen (2 required)	Vibrating screens, 250 t/h
Vibrating Feeders for Car Unloading (6 required)	0 to 750 t/h
Coal Belt Scale	0 to 3000 t/h, 60 in. belt
Coal Sampling System	0 to 3000 t/h, 60 in. belt
Coal Crusher	0 to 10 t/h, 10 in. lumps
Magnetic Coal Cleaner	500 t/h
Coal Fines-Tar Mixers (2 required)	Steam jacketed auger mixers at 200 F, 60,000 lb/hr
Dust Control System	Four-6000 ft ³ /min bag-type dust collectors
CO ₂ Fire Protection System	Adequate to service dust collectors
Vibrating Feeders for Coal Piles (8 required)	0 to 200 t/h
Coal Silos (8 required)	250 ton each
Vibrating Feeders (2 required)	250 t/h
Vibrating Feeders (2 required)	50 t/h
Holding Hopper	375 ton capacity
Holding Hopper (2 required)	50 ton capacity each
Gasifier Hopper (10 required)	20 ton capacity each
Gasifier Hopper (4 required)	10 ton capacity each
Sulfur Storage Tank	58,000 ft ³ required, 45 ft dia., by 50 ft high
Ash Storage Tank (2 required)	214,000 ft ³ each, 70 ft dia., by 70 ft high
<u>2.0 Electrical Systems</u>	
Gas Turbine Transformer (2 required)	260 MVA, 24 kV-500/13.8 kV, 65 C, FOA, 3 ϕ , 60 Hz
Steam Turbine Transformer (1 required)	240 MVA, 25-500 kV, 65 C, FOA, 3 ϕ , 60 Hz
Startup Transformer (1 required)	20/26.5/33 MVA, OA/RA/FOA, 65 C, 500-13.8 kV, 3 ϕ , 60 Hz
Miscellaneous Transformers (20 required--estimated)	1680 kVA, 13.8-480, 277 kV, OA, 65 C, 3 ϕ , 60 Hz
4.16 kV LCC Transformer (2 required)	5500 kVA, 13.8-4.16 kV, OA, 65 C, 3 ϕ , 60 Hz

Table B-10 (Cont'd)

ITEM	DESCRIPTION
<u>2.0 Electrical Systems (Cont'd)</u>	
Emergency Diesel Generator	1000 kW, 1250 kVA, 0.8 pf, 480 V, 3 ϕ , 60 Hz
<u>3.0 Fluid Systems</u>	
Booster Steam Turbine Condenser (2 required)	5560 ft ² of 1.0 in. 18 BWG 90-10 Cu-Ni tubes, 63,500 lb/h, 52.5 $\times$ 10 ⁶ Btu/h duty, 2.3 in. HgA exhaust pressure
Main Steam Turbine Condenser (1 required)	Two-shell, single-pressure condenser complete with water boxes and air ejection equipment; 115,090 ft ² of 30 ft, 90-10 Cu-Ni tubes; 1,170,000 lb/hr, 1,099 $\times$ 10 ⁶ Btu/h duty, 2.3 in. HgA design oper. pressure
Circulating Water Pump (3 required)	Vertical centrifugal pump rated at 1/3 capacity; 47,500 gal/min. 60 ft TDH, one-stage bell suction, C.I. casing, 316 SS shaft and impeller, complete with 1000 hp motor
Condensate Pump (2 required)	Vertical, half-capacity, 6 stage centrifugal pump with 100 hp electric motor driver; C.I. casing, ASTM-A296 impeller, and 416 SS shaft; 1400 gpm design flow at 235 ft TDH
Boiler Feed Pump (2 required)	Horizontal, centrifugal half-capacity pump with 4000 hp electric motor driver, C-5 casing A-296 SS impeller and ASTM-217, GR A-276 410 SS shaft; pump rated at 1430 gpm, 6353 ft TDH
Bucket Coolant Pump (2 required)	Horizontal, centrifugal, full-capacity pump with 75 hp electric motor driver, ASTM-217 GR C-5 Casing, SS shaft and impeller; 295 gpm design flow at 578 ft TDH
Nozzle Coolant Pump (2 required)	Horizontal, centrifugal, full-capacity pump with 1000 hp electric motor driver, ASTM-217 GR C-5 casing, SS shaft and impeller; 770 gpm design flow at 3685 TDH
Saturator Spray Water Pump (2 required)	Horizontal, centrifugal, half-capacity pump with 20 hp electric motor driver; 80 gpm design flow with 600 ft discharge head
Booster Drive Condenser Pump (2 required)	Half-capacity centrifugal pump with 7.5 hp electric motor driver, C.I. casing, and 416 SS shaft and impeller; 55 gpm design flow with 200 ft TDH

Table B-10 (Cont'd)

ITEM	DESCRIPTION
<u>3.0 Fluid Systems (Cont'd)</u>	
Cooling Tower (8 cells required)	13,000 gal/min, 36 ft × 75 ft wide × 47 ft height, 19° approach, 175 × 10 ⁶ Btu/h/cell, F.D. wood cells
Deaerator (1 required)	Tray-type deaerator with 16,000 gallon storage tank; 3560 gpm outlet at 30 psig design pressure
Closed Heater (1 required)	Heating (tubeside) flow of 50,000 lb/hr at 50 psia, 281 F inlet; 184 F outlet; 1590 ft ² surface area
Bucket Coolant Polisher (1 required)	146,000 lb/hr, 184 F inlet, full flow polisher
Process Desuperheater (1 required)	20,000 lb/hr of desuperheated steam at 65 psia, 298 F
Flash Tank (2 required)	6 ft dia., 30 ft high, pressure vessel coded tanks
Process Desuperheater Supply Pump (2 required)	Half-capacity centrifugal pump with 1/2 hp electric motor driver; 32 gpm design flow rate with 30 ft TDH
<u>4.0 Miscellaneous Mechanical Systems</u>	
Hot Exhaust Booster Compressor (2 required)	Horizontal, axial flow compressor with lubricating oil system, 440,000 lb/h saturated air, 1.6 pressure ratio; discharge at 375 psia, 506 F
Booster Compressor Turbine Driver (2 required)	8000 hp/8000 rpm condensing steam turbines; 63,500 lb/h throttle flow at 520 psia/615 F, 2.3 in. HgA exhaust pressure (5.3 MW)
Station Air Compressors (3 required)	400 scfm, 100 psig, 125 hp nonlubricated, for instrument and service air requirements complete with aftercooler and moisture separator
Station Air Receivers (3 required)	4 ft dia. × 12 ft height, ASME vessels complete with instruments and drain trap
Station Auxiliary Boiler (1 required)	150,000 lb/h, 150 psig package boiler complete with fuel, chemical, feedwater and condensate systems, including deaerator

Table B-11
BALANCE-OF-PLANT EQUIPMENT LIST
GAS CLEANUP SYSTEM

EQPT. NO.	SERVICE	DESCRIPTION
E-204	Heater Exchanger for Dewatering and Rewatering Gas, Before and After H ₂ S Removal	Gas-gas shell and tube, 8 shells in series: <u>each shell</u> 18,900 ft ² of heat transfer surface, gases 350 psi, stainless 304, 3/4 in. tubes, BWG gage 22, one inch triangular pitch, no baffle, 6.2 ft dia., 20 ft tube length, 4800 tubes, with fog nozzle upstream of inlet to tube side head, and condensate drain-off lines from tube side bottom head and bottom of shell side
E-205	Heat Exchanger for Final Dewatering of Gas	Gas-cooling water, shell and tube, 3 shells in series; each shell as in E-204 <u>except</u> no fog nozzles; gas on tube side
V-207	Oily Water Separator (3 required)	450 gal/min, 350 psia, 330 F service, 6 ft dia., 20 ft high
P-210A	Pump, Condensate to Gas Rewatering (Stream 32) (2 required: 1 reg, 1 spare)	Centrifugal, 36 hp, 27 kW electric motor, 160 gal/min, inlet 65 psia, outlet 370 psia, temperature 298 F
P-210B	Pump, Treated Water to Gas Rewatering (Stream 34) (2 required: 1 reg, 1 spare)	Centrifugal, 7 hp, 5 kW electric motor, 32 gal/min, inlet 65 psia, outlet 370 psia, temperature 57 F
P-211	Pump, Water from Oil Separator (Stream 43) (2 required: 1 reg, 1 spare)	Centrifugal, 18 hp, 14 kW electric motor, 410 gal/min, inlet 330 psia, outlet 390 psia, temperature 328 F
P-212	Pump, Hot Water to Rewatering (Stream 37) (2 required: 1 reg, 1 spare)	Centrifugal, 8 hp, 6 kW electric motor, 225 gal/min, inlet 320 psia, outlet 370 psia, temperature 317 F
P-213A	Pump, Condensate Water to Gasifier Feed (Stream 31) (2 required: 1 reg, 1 spare)	Centrifugal, 8 hp, 6 kW electric motor, 32 gal/min, inlet 320 psia, outlet 425 psia, temperature 298 F
P-213B	Pump, Treated Water to Claus Heater (Stream 33) (2 required: 1 reg, 1 spare)	Centrifugal, 40 hp, 30 kW electric motor, 148 gal/min, inlet 65 psia, outlet 435 psia, temperature 57 F
P-214	Pump, Oil and Phenol (Stream 8) (2 required: 1 reg, 1 spare)	Centrifugal, 4 hp, 2.5 kW electric motor, 70 gal/min, inlet 330 psia, outlet 400 psia, temperature 328 F

Table B-11 (Cont'd)

EQPT. NO.	SERVICE	DESCRIPTION
P-215A	Pump, Warm Water to Process Heater (Stream 39) (2 required: 1 reg, 1 spare)	Centrifugal, 16 hp, 12 kW electric motor, 240 gal/min, inlet 310 psia, outlet 400 psia, temperature 220 F
P-215B	Pump, Hot Water to Process Heater (Stream 40) (2 required: 1 reg, 1 spare)	Centrifugal, 17 hp, 13 kW electric motor, 238 gal/min, inlet 320 psia, outlet 400 psia, temperature 287 F
V-302	Knockout Drums, Pre-Alkazid Absorption (2 required)	5.3 dia. x 10 ft SS knockout drum with a demister, 350 psia
T-304	Alkazid Absorption Towers (2 required)	9 ft dia. x 20 ft aluminum towers with internals, 350 psia
	Sieve Plates (4 per Tower)	9 ft dia. aluminum sieve trays
E-303	Cooler, Regenerated Alkazid Solution (2 required)	Countercurrent shell and tube aluminum heat exchangers, 4610 ft ² /exchanger
P-308	Pumps, Alkazid Solution Recycle (4 required: 2 reg, 2 spare)	SS centrifugal pumps TDH of 345 psia @ 865 gal/min, 290 bhp
E-309	Heat Exchangers, Alkazid Lean, Rich Solution (2 required)	Countercurrent shell and tube aluminum heat exchangers, 6,980 ft ² /exchanger
T-305	Alkazid Regeneration Tower	12.3 ft dia. x 30 ft aluminum tower with internals, 50 psig
	Sieve Trays (9 required)	12.3 dia. aluminum sieve trays
E-310	Alkazid Regeneration Tower Reboiler	SS thermosyphon reboiler, 7.605 ft ² , 50 psig
E-311	Alkazid Regenerator Reflux Cooler/Condenser	Countercurrent shell and tube SS heat exchanger, 11,870 ft ² , 50 psig
V-312	Stripper Overhead Receiver	4.8 ft dia. x 10 ft SS knockout drum with a demister, 1.2 ton, 50 psig
P-313	Pumps, Stripper Reflux (2 required: 1 reg, 1 spare)	SS centrifugal pump TDH 15 psia, 400 gal/min, 10 bhp
E-314	Acid Gas Cooler/Condenser	Shell and tube SS heat exchanger, 2,765 ft ² , 50 psig

Table B-11 (Cont'd)

EQPT. NO.	SERVICE	DESCRIPTION
V-315	Acid Gas Knockout Drum	4.3 ft dia. x 10 ft SS with a demister, 50 psig
V-318	Alkazid Solution Storage Tank	Aluminum cylindrical storage tank, fixed roof, 500 bbl
PL-306	Claus Plants to Oxidize the Recovered H ₂ S to Elemental Sulfur (3 required: 2 operating, 1 spare)	85 lt/d capacity with minimum conversion efficiency of 95%, 3 conversion stages, sulfur powder as product
F-316	Leakgas and Recycle Tar Incinerator	Furnace system to handle 46 x 10 ⁶ Btu/h
E-317	Incinerator Waste Heat Recovery Package	Stainless 304 tubes to contain liquids and gases at 300 to 400 psig. 40 x 10 ⁶ Btu/h heat exchanged
	Piping for Main Gas Flow Through Items E-204 and E-205	Stainless steel pipe 36 in. o.d., 350 psig, 350 F
	Piping for Main Gas Flow Through Items V-302 and T-304	Stainless steel pipe 24 in. o.d., 350 psig, 350 F

Table B-12

CYCLE ELECTRICAL OUTPUT
OPEN CYCLE GAS TURBINE COMBINED - WATER COOLED - LBTU GASIFIER

CHARACTERISTIC	MWe AT 6 Hz AC
Total prime cycle output (gas turbine; 2 units)	456.5
Total bottoming cycle output (steam turbine; 1 unit)	208.6
Total gross output (MWe at 60 Hz ac)	665.1
Total auxiliary losses, including transformer losses (MWe at 60 Hz ac)	25.1
Net power plant output (MWe at 60 Hz ac 500 kV)	640.0

Table B-13

AUXILIARY LOSS BREAKDOWN
OPEN CYCLE GAS TURBINE COMBINED - WATER COOLED - LBTU GASIFIER

ITEM	ASSUMPTIONS	UNITS	MWe EACH	TOTAL MWe	RATED MWe
Major Pumps					
Boiler feedwater	$\Delta P = 2750$	2	2.49	4.98	5.22
Bucket coolant	$\Delta P = 250$ psia	1	0.04	0.04	0.06
Nozzle coolant	$\Delta P = 1500$ psia	1	0.59	0.59	0.94
Circulating water	Proportional to cooling duty	3	0.47	1.42	2.02
Condensate	$\Delta P = 108$ psia	2	0.08	0.16	0.16
Turbine Auxiliaries					
Gas turbines	Advocate estimate	2	1.16	2.31	
Steam turbine	~0.5% of S.T. output	1	1.04	1.04	
Gas Cleanup System		-	1.20	1.20	1.20
Coal Handling		-	3.48	3.48	5.00
Cooling Tower Fans	Proportional to heat duty	10	0.07	0.69	1.50
Hotel Load	~0.75% of generation (A/E estimate)	1	4.79	4.79	6.38
Compressors	A/E estimate	3	0.09	0.28	0.28
Makeup Water Treatment	A/E estimate	1	0.37	0.37	0.50
Intake Structure	A/E estimate	1	0.52	0.52	0.70
Transformers	~0.5% of gross generation	3	-	<u>3.19</u>	
				25.06	

Table B-14

MAJOR COMPONENT AND SUBSYSTEM CAPITAL COST SUMMARY
OPEN CYCLE GAS TURBINE COMBINED - WATER COOLED - LBTU GASIFIER

MAJOR COMPONENT OR SUBSYSTEM	NUMBER OF UNITS	COST/UNIT FOB (M\$)	COMPONENT OR SUBSYSTEM COSTS FOB (M\$)	BOP + MATERIALS (M\$)	SITE + LABOR (DIRECT + INDIRECT) (M\$)	TOTAL INSTALLED COST (M\$)
Fuel Handling and Preparation						
Gasifier subsystem	12	1.850	22.310	-	3.661	25.971
Gasifier cleanup subsystem	1	-	-	17.790	12.547	30.337
Prime Cycle						
Gas turbine generator	2	18.179	36.358	0.123	0.982	37.463
Bottoming Cycle						
Heat recovery steam generator	2	5.500	11.000	0.460	2.902	14.362
Steam turbine generator	1	9.880	9.880	0.035	1.005	10.920

plant cost of \$279.46 million in Table B-15 is obtained by including 15 percent of the total BOP labor and material cost for architect-engineering services and home office fees, and by further allowing 20 percent of the subtotal cost for contingency.

NATURAL RESOURCES AND ENVIRONMENTAL INTRUSION

The natural resources required for the plant are presented in Table B-16. The total water demand of $1.06 \text{ m}^3/\text{GJ}$ (0.391 gal/kWh) is based on the following assumptions:

- Cooling water evaporation and drift losses amount to $0.366 \text{ m}^3/\text{GJ}$ (102 gal/MBtu) of heat rejected, and the blowdown losses are estimated to be $0.12 \text{ m}^3/\text{GJ}$ (32 gal/MBtu). The combined water loss from these two sources alone is 76 percent of total plant demand.
- Steam system makeup water is estimated at 1 percent of the steam flow, and boiler drum blowdown at 0.5 percent.
- Gasifier process water demand is in the form of water spray in the coarse coal train and water injection in the air blast; the latter is derived from exhaust steam condensate of the booster-compressor drive turbine, and thus extracted from the steam cycle.
- Gas cleanup system water demand consists of imported process steam extracted from the steam cycle and process water flows. A small fraction of the consumed water leaves the cleanup system in the form of process blowdown.
- Water loss from the gas turbine bucket coolant loop and water injection in the cooling air are estimated by the data of Table B-5.
- "Hotel" usage, taken at 3 percent of total water consumption, represents general plant use.

The gaseous emission through the stacks, the thermal pollution, and the waste discharge from the plant are listed in Table B-17. The gaseous emissions are both from the incinerator stack of the LBtu gas cleanup system and from the gas turbine combustion products discharged through the HRSG stacks. The SO_x and NO_x emission rates (kg/GJ [lb/MBtu] in HHV of coal) meet the solid fuel emission standards; these rates are achieved by removing an appropriate amount of H_2S from the LBtu fuel gas before combustion. The particulates in the form of ash particles in the exhaust gas are assumed to be negligible, since the fuel gas is expected to be free of any particulate matter after its passage through the gas cleanup system.

The combined heat rejected from the cooling towers and from the stack (both latent and sensible) accounts for a major fraction of the total heat rejection from the plant. The difference is distributed throughout the plant.

The plant wastes associated with the LBtu fuel plant include the ash and the sulfur. The wastewater discharge is associated with the cooling tower blowdown.

Table B-15

BALANCE-OF-PLANT CAPITAL COST BREAKDOWN
OPEN CYCLE GAS TURBINE COMBINED - WATER COOLED - LBTU GASIFIER

CATEGORIES	COMPONENT CAPITAL COST (M\$)	DIRECT LABOR (M\$)	INDIRECT FIELD (M\$)	MATERIALS (M\$)	TOTAL (M\$)
1.0 Steam generators	11.26	1.53	1.37	0.46	14.62
2.0 Turbine generator	46.24	1.05	0.94	0.16	48.39
3.0 Process mechanical equipment		2.36	2.13	15.95	20.44
4.0 Electrical		8.07	7.27	11.28	26.62
5.0 Civil and Structural		7.11	6.50	8.74	22.25
6.0 Process piping and instrumentation		6.31	5.68	6.69	18.68
7.0 Yardwork and miscellaneous		1.59	1.43	2.00	5.02
8.0 Gasification cleanup system		6.60	5.94	17.79	30.33
9.0 Gasifier	22.31	1.97	1.78	0.51	26.57
Subtotal	79.81	36.59	32.94	63.58	212.92
A/E Service and Contingency					66.54
Total Estimated Plant Cost (1975 dollars)					279.46

Table B-16

NATURAL RESOURCE REQUIREMENTS
OPEN CYCLE GAS TURBINE COMBINED - WATER COOLED - LBTU GASIFIER

COMPONENT	VALUE
Coal (lb/kWh)	0.719
Water Total (gal/kWh)	0.391
Water Consumption	
Cooling tower evaporation	0.226
Steam system makeup	0.003
Gasifier process	0.024
Gas cleanup system	0.035
NO _x suppression	0
Bucket coolant loss	0.018
Injection in blocking air	0.002
Hotel usage	0.011
Blowdown Treated Waste	
Cooling tower blowdown	0.071
Boiler drum blowdown	0.001
Total Land (acres/100 MWe)	12.08
Main plant	9.30
Disposal land	2.78

Table B-17
ENVIRONMENTAL INTRUSION
OPEN CYCLE GAS TURBINE COMBINED -- WATER COOLED -- LBTU GASIFIER

EMISSIONS	INPUT (lb/MBtu)	OUTPUT (lb/kWh)
SO _x	1.2000	0.0093
NO _x	0.3790	0.0029
HC	0.0175	0.0002
CO	<0.0175	<0.0002
Particulates	0	0
THERMAL POLLUTION		
Heat rejected, cooling towers (Btu/kWh)		2218
Heat rejected, stack (Btu/kWh)		1329
Heat rejected, total (Btu/kWh)		4341
WASTE	(lb/kWh)	(Mlb/day)
Ash	0.069	1.06
Sulfur	0.023	0.35
Water Discharge	0.598	9.19

SUMMARY OF PERFORMANCE AND COST

The performance and cost estimates for this cycle are summarized in Table B-18. The plant has an overall energy efficiency of 44 percent, based on HHV of as-received coal, with an equivalent coal consumption of 90.6 kg/GJ (0.719 lb/kWh). The solid waste includes coal ash discharged from the gasifier and the elemental sulfur from the Claus plant.

The plant capital cost of \$474/kW (1975\$) is calculated on the basis of 5 years' construction time, derived from the detailed field labor man-hour estimate of Tables B-8 and B-9 and assuming that the plant enters service in the year 2000.

The cost of electricity, calculated for three capacity factors, is based on the following contributions:

- Capital. An 18 percent fixed charge rate is applied to the plant capital cost of \$474/kW.
- Operating and Maintenance. The O&M contribution is derived from three factors:

Table B-18

SUMMARY OF PERFORMANCE AND COST
OPEN CYCLE GAS TURBINE COMBINED - WATER COOLED

PARAMETER	VALUE
Net Power Output (MWe, 60 Hz, 500 kV)	640
Thermodynamic Efficiency (%)	-
Power Plant Efficiency (%)	44
Overall Energy Efficiency (%)	44
Coal Consumption (lb/kWh)	0.719
Total Solid Wastes (lb/kWh)	0.092
Plant Construction Time	5 years
Total Estimated Plant Cost (1975 dollars)	279.5 M\$
Plant Cost Estimate in Year of Construction	
Start	984.8 M\$
Escalation and Interest During Construction	479.6 M\$
Capital Cost in Year 2000, When Plant	
Enters Service	1464.5 M\$
Capital Cost De-escalated to 1975 Dollars	303.4 M\$
Cost per Installed kW (1975 dollars)	474.0 \$/kW
Levelized Cost of Electricity (mills/kWh in 1975 dollars)	
Capacity Factor	0.70 0.40 0.15
Capital	13.9 24.3 64.9
Fuel	17.5 17.5 17.5
O&M	<u>3.8</u> <u>4.1</u> <u>5.2</u>
Total	35.2 45.9 87.6

(a) Maintenance: For this plant, maintenance costs are estimated as follows:

<u>Category</u>	<u>Mills/kWh</u>
Gasifier	0.28
Cleanup system	0.33
Gas turbine	0.64
Heat recovery steam generator	0.08
Steam turbine-generator	0.10
Makeup water treatment	0.01
Water intake structure	0.01
BOP	<u>0.29</u>
Total	1.74

(b) Operating Labor: It is assumed that a total of 40 people of various skills would be required for the plant operation, with an average salary of \$20,000/year including fringe benefits and overhead. The payroll charge is the fixed part of the O&M cost.

(c) Operating Consumables: It is assumed that conventional consumables (treated makeup water, lubricants, miscellaneous supplies) would cost \$0.35 M per year for this plant, resulting in 0.09 mills/kWh contribution.

Thus the fixed O&M cost is 1.25 \$/kWyr while the variable cost is 1.83 mills/kWh.

A 30-year levelization factor of 1.88 is applied to these costs in computation of cost of electricity.

- Fuel. The fuel charge is calculated for \$0.89/GJ (\$0.94/MBtu) for Illinois No. 6 coal, and on the basis of a 30-year levelization as described in Section 3.

BACKGROUND INFORMATION ON LOW-BTU GAS CLEANUP SYSTEM

The major function of the gas cleanup system is to remove hydrogen sulfide (H_2S) from the fuel gas so that the quantity of sulfur dioxide (SO_2) in the combusted gas will not exceed legal limits for emission to the atmosphere. The cleanup system also manufactures solid sulfur, incinerates waste fuels from the gasification complex, and separates the oil and water in the liquid from the complex.

The cleanup system includes an Alkazid plant for removing hydrogen sulfide from the gas, a Claus plant for sulfur recovery, a standard incinerator, and a simple three-drum gravity liquid-separation system. Only state-of-the-art equipment and processes are specified.

The system is relatively simple because the emission standards assumed were those applying to the combustion of solid fuel.

Several key engineering features of the cleanup system are discussed here. First the sulfur balance for the system is presented; then the absence of ammonia removal equipment is justified. The characteristics of the dewatering-rewatering heat exchangers are discussed; then the Alkazid plant for H_2S removal is discussed in detail. The function of the Claus plant for sulfur recovery is explained, and the water systems are discussed. Finally, particulate carryover questions are discussed.

Sulfur Balances

The sources of emission to the atmosphere were studied to ensure that the environmental sulfur emission limit is met. The requirement is for no more than 0.54 kg (1.2 pounds) of SO_2 emitted per million Btu of solid-fuel higher heating value to be charged to the plant. Since the coal charged to the plant has a heating value of 25,093 kJ/kg (10,788 Btu/lb) and a mass flow rate of 57.9429 kg/s (459,864 lb/hr), the allowable SO_2 emission rate for the entire plant is 0.750 kg/s (5953 lb/hr). This SO_2 is formed by oxidation of H_2S , of COS, or of the sulfur in

the incinerated blowdown tar. The cleanup system must remove enough sulfur as elemental sulfur so that the sum of the SO_2 emitted with incinerator flues and the SO_2 emitted with the power gas flues will be no greater than 0.7501 kg/s (5953 lb/hr). The cleanup system contains no COS hydrolysis equipment. Thus the COS formed in the gasifier and entering with the raw gas will pass into the product gas unchanged and will form SO_2 in the power furnace. The Alkazid plant removes H_2S from the product gas to a level that will allow the limit to be met. Five percent of the H_2S removed by the Alkazid plant will not be converted to elemental sulfur in the Claus plant and will be emitted to the atmosphere as SO_2 when the tail gas is incinerated. The emission standards are met when the Alkazid plant removes 95.28 percent of the H_2S entering with the raw gas. The cleaned gas contains in volume (dry) 491 parts per million of H_2S , and 787 parts per million of COS.

Table B-19 shows the disposition of the sulfur entering the cleanup system.

Table B-19
EQUIVALENT SO_2 IN STREAMS

IMPORT STREAMS	Lb/Hr
Raw gas, COS	2,495
Raw gas, H_2S	33,007
Leak gas, COS	22
Leak gas, H_2S	291
Leak gas, tar	1
Blowdown tar	15
Total Import	35,831
EXPORT STREAMS	
Cleaned gas, COS	2,495
Cleaned gas, H_2S	1,557
SO_2 from leak gas flues	314
SO_2 from blowdown tar flues	15
SO_2 from tail gas flues	1,572
Subtotal to Gaseous Emissions	5,952
Elemental sulfur	29,878
Total Export	35,831

Ammonia Limits

Nitrous oxides are formed by combustion of ammonia, and by oxidation of N_2 in the combustion air. To meet solid fuel emission standards, .032 kg of NO_2 may be emitted to the atmosphere per GJ of solid-fuel higher heating value ($0.716 NO_2/MBtu$). The combustor performance estimates for the total NO_x production from both fuel and air indicated that the emission standards would be met without removal of NH_3 from the raw gas.

Dewatering and Rewatering Heat Exchange

The gas heat exchangers used were constrained by the total cleanup system pressure drop. Consequently, a large amount of surface area had to be provided. Table B-20 summarizes the characteristics of the gas-gas dewatering and rewatering heat exchanger E-204 in the cleanup system.

Table B-20
E-204 HEAT EXCHANGER CHARACTERISTICS

PARAMETER	DESCRIPTION
Number of shells	8
Heat exchange surface per shell (ft ²)	18,900
Tube length (ft)	20
Shell diameter (ft)	6.2
Heat transferred (10^6 Btu/h)	265
Average ΔT_{LM} countercurrent (F)	67
Average overall heat transfer coef U (Btu/hr ft ² F)	40
Assumed heat transfer efficiency factor	0.67
Approximate total pressure drop (psi) (8 in. series shell side plus 8 in. series tube side)	18

Alkazid Plant

Alkazid is the trade name for a gas-sweetening process using concentrated water solutions of salts of amino acids. The process was developed in the 1930s in Germany. Twenty-two Alkazid plants were built abroad between 1953 and 1969 by the German affiliates of one U.S. licensor of the Alkazid process.*

*Alkazid solution and Alkazid process design data can be obtained from Badische Anilin & Soda-Fabrik, AG, Ludwigshafen am Rhein, Germany. Davy Powergas, Inc., of Lakeland, Florida, is one of the U.S. companies licensed to market the process.

Alkazid Solution

The Alkazid scrubbing agent is a nonvolatile compound which in solution has the advantage of a preferential affinity for H_2S compared to CO_2 . To maximize the volume of working fluid available in the power gas, it is desirable to minimize the CO_2 removal that takes place when H_2S is removed from the gas. If less CO_2 is removed with the H_2S , less steam is required to regenerate the solution. The Alkazid system that minimizes the CO_2 absorption is called Alkazid DIK. The sorbent is a solution of the potassium salt of diethyl glycine or dimethyl glycine. The amine group in the salt is basic and has a natural affinity for any gas that dissolves and forms an acid in water solution. Both H_2S and CO_2 form acidic complexes in water (that is, they are acid gases), and both form weak complexes with the amine group in Alkazid DIK. The potassium amino-acid salt is a salt of a strong base and a weak acid. In water solution, the salt dissociates, and the amino-acid ion forms the neutral acid by capturing a hydrogen ion from water. Thus the water that lost the hydrogen ion survives as OH^- . This enhances the basic character of the salt. When the gases are captured in the sorbent solution, the vapor pressures of the gases are reduced, as compared with the vapor pressure when the same amount of gas is dissolved by pure water. The sorbent solution can thus absorb roughly 100 times as much acid gas per pound of solution as can pure water. The sorbent solution can be loaded with acid gas approximately until there is one molecule of captured acid gas for each molecular amine group in the amino acid. In practice, however, the loading is usually kept substantially below this level, to increase "driving forces" for absorption. Also, the partial pressure of the acid gases in the gas being scrubbed affects the degree of loading that is possible. The gas entering the absorber must have an acid gas partial pressure higher than the acid gas vapor pressure of the loaded sorbent leaving the absorber.

Alkazid Absorbers

About 95 percent of the incoming H_2S is removed in the absorbers to bring the H_2S level in the cleaned gas to 491 parts per million as required. The absorption occurs readily, and only a small number of tower trays (four) are needed to effect the required removal. The assumed tray efficiency of 20 percent used to calculate the number of trays is conservative. Two towers operating in parallel are needed to accommodate the large volume of gas flow. Gas enters the bottom of each tower and leaves through the top. Fresh, lean sorbent is withdrawn from the bottom of each tower. The liquid and gas flow countercurrent. During the absorption, both H_2S and CO_2 are absorbed. However, the affinity of the sorbent for H_2S is about 28 times as great as for CO_2 . Thus, even though the average CO_2 partial pressure in the tower is 30 times as great as that of H_2S , the sorbent actually absorbs CO_2 and H_2S in roughly equal molar quantities. Thus, 12.7 percent of the CO_2 is removed. The balance of

the CO_2 remains as working fluid in the clean gas. Two towers operating in parallel are provided to present enough cross-sectional area for gas flow to maintain the gas velocity below 0.61 m/s (2 ft/sec). This prevents tray flooding, a condition which spoils the towers' absorption capability.

Alkazid Regenerator

The loaded solution from the absorption tower is regenerated by stripping out the H_2S and CO_2 with an ascending current of water vapor. This regenerator tower operates at a high temperature and a low pressure so the vapor pressure of the acid gases leaving the solution is higher than the partial pressure of the acid gases in the vapor phase. This ensures that the acid gases leave the liquid phase and enter the vapor phase. The conditions for operating a stripper are therefore just the opposite of those for an absorber, which performs best at low temperature and high pressure, so that the acid gases tend to leave the gas phase and enter the liquid phase. The degree to which acid gases must be stripped out of the solution in the regenerator is determined by the inlet solution requirements of the absorber. In the regenerator, the ascending water vapor to perform the stripping is obtained by boiling the solution in the reboiler. Steam is used to provide the heat for boiling the solution. The heat added in the boiler is removed by the condenser, which cools and dewateres the acid gas leaving the stripper. One tower of reasonable diameter provides enough cross-sectional area to keep the acid gas and vapor flow velocity in the tower to approximately 1.83 m/s (6 ft/sec).

Claus Plant

The Claus plant converts H_2S in an acid gas into elemental sulfur. Claus plants are standard packaged systems which can be purchased on a turnkey basis. Usually they operate at 95 percent efficiency. That is, 5 percent of the entering sulfur remains unconverted and leaves as H_2S and SO_2 in the tail gas. Claus plants work best when the amount of CO_2 diluent is low, as in our system. That is, the one-to-one mole ratio of H_2S and CO_2 in this cleanup system is good for a Claus plant. When more CO_2 is present in the acid gas, the cost of the Claus plant is higher. A third of the entering acid gas is incinerated with stoichiometric air to form SO_2 . The hot gases are cooled in a waste heat recovery boiler so when they are mixed with the acid gas that was bypassed, the temperature will be around 505 K (450 F). The mixed gases react according to the equation:

However, only part of the H_2S reacts in this way in the mixing environment without catalyst. The gas is cooled to condense the sulfur vapor thus formed. Then it is passed through three

successive cycles of reheating, reaction over catalyst, and cooling to condense liquid sulfur. Three Claus plants are provided, two operating and one spare. This configuration assures complete availability of the Claus plant module.

Process Water Systems

Foul water condenses from the gas during dewatering, and a foul process water enters with oil and phenol from gasifier washer coolers. These foul waters contain dissolved H_2S , NH_3 , CO_2 , and phenols. The water separated from the oil and phenol is returned to the washer coolers, and some additional makeup water is sent to the washer coolers. This makeup water evaporates and enters the cleanup system with the gas as saturated vapor. There is no need to clean up the water sent to the washer coolers. All the water for makeup is taken from the dewatering condensate. Some heat must be added to the makeup water before it is sent to the washer coolers. The water sent to the washer coolers may even contain a small amount of residual oil without interfering with the quenching function. Thus the oil/water separation scheme can be inexpensive and somewhat "sloppy." This tolerance of contamination in both streams leaving the oil/water separator has been exploited in Bechtel's design. Some foul water is remixed with the gas in rewatering, as mentioned before. No more than 31.8 kg (70 lb.) per hour of H_2S will be added to the gas along with this water, however. Since this flow of H_2S is so small, it has been ignored in the mass balance, pending a complete analysis of the amount of H_2S leaving with the condensate from each shell of heat exchanger banks E-204 and E-205. Negligible change to equipment or costs would result from taking full account of the small flow of H_2S reintroduced into the gas during rewatering.

Steam-Condensate Systems

The cleanup system requires import steam and import boiler feedwater. The mix of the two depends upon the heat balance of the cleanup system. The mass of steam plus condensate imported is calculated as follows. Water enters the cleanup system with the oily water from the washer coolers and also as water vapor in the entering raw gas. Water leaves the cleanup system as return water to the washer coolers, as feedwater to the gasifiers, as water vapor in the product rewatered clean gas, and as blowdown from the boilers and the process water systems. More water leaves than enters. The difference must be additional entering water. Heat is added to the steam-condensate systems in the Claus plant and in the incinerator systems. Heat is removed from the steam-condensate systems by the Alkazid reboiler. Heat also leaves the systems with the export gasifier feedwater and washer cooler makeup water. The amount of water mass and heat that must be added to the system to make inflow mass and heat rates balance outflow rates can be calculated. This determines the ratio of steam and liquid water imported into the cleanup system.

Particulate Removal

As mentioned earlier, the Alkazid absorbers contain a particulate removal zone just before the gas exit at the top of each column. This is judged sufficient to assure adequate removal of any entrained Alkazid solution agent carried up with the gas. Also, the gas rewatering process should catch any residual particulates. Consequently, the cleanup system probably provides adequate protection against carryover of Alkazid sorbent compound into the gas turbines.

B.2 ADVANCED STEAM CYCLE (16,550 kPa/811 K/922 K [2400P/1000F/1200F]) — ATMOSPHERIC FLUIDIZED BED

INTRODUCTION

The advanced steam cycle power plant with atmospheric fluidized beds (AFBs) achieves the functions of combustion, steam generation, and sulfur capture in the four modular AFBs that replace a conventional steam boiler requiring wet flue gas scrubbers to remove sulfur dioxide. A simplified cycle schematic is presented in Figure B-14 showing the major pieces of equipment. The AFB and items to its left are concerned with the release of chemical energy, its transfer as thermal energy, and the management of the chemical effluents from the plant. The center of the figure represents the steam turbine prime cycle that converts thermal energy to mechanical and then to electrical energy. At the far right, the condenser and cooling towers are the heat rejection system for the prime cycle.

Figure B-14. Simplified Schematic Diagram of Advanced Steam Cycle —
Atmospheric Fluidized Bed

The cycle parameters are presented in Table B-21. The Illinois No. 6 coal contains 3.9 percent sulfur. Eighty-three percent of the sulfur must be captured to meet the environmental emission limit of 0.51 kg/GJ (1.2 lb/MBtu) of fuel heat release. The capture medium is limestone fed into each of the six main fluidized beds (in each module) at twice the rate that would capture all of the sulfur. The 1116 K (1550 F) main bed operating temperature was selected to maximize sulfur capture at approximately 85 percent of that present in the coal. Unburned carbon is conveyed from the main beds in the fly ash of the gas stream and in the solids tapped from each bed. The 95 percent of the fly ash recovered in cyclone separators and the tapped solids are recycled to a carbon burnup cell, where a higher

Table B-21
CYCLE PARAMETERS
ADVANCED STEAM - ATMOSPHERIC FLUIDIZED BED

PARAMETER	VALUE OR DESCRIPTION
FUEL	
Illinois No. 6	10788 Btu/lb Higher Heating Value
Limestone	\$.94/MBtu, 3.9% Sulfur
	Sulfur Capture Medium
	0.257 lb/lb Coal
FURNACE	
Atmospheric Fluidized Bed Combustor and Steam Generator Modules (4)	
Main beds (6)	Coal and Limestone
	1550 F, 20% Excess Air
Carbon burnup cell (1)	Fly Ash and Solids Drain
	2000 F, 30% Excess Air
PRIME CYCLE - STEAM PLANT	
Working Fluid	Steam
Turbine Inlet	2415 psia, 1000 F
Reheat	494 psia, 1200 F
Condenser	2.3 in. Hga, 106 F
Final Feedwater	3018 psia, 590 F
HEAT REJECTION	
Wet Mechanical Draft	24 Cells
Cooling Towers	
Stack Gas Temperature	260 F

temperature of 1366 K (2000 F) and increased excess air of 30 percent produce a substantial burnup of residual combustibles. In essence, the main beds release energy while capturing sulfur as calcium sulfate. The carbon burnup cell releases additional energy but without the burden of sulfur capture; the result is a high boiler efficiency.

The steam cycle uses conventional throttle conditions but reheats steam to 922 K (1200 F). Another unconventional feature of the steam turbine cycle is the use of two feedwater heaters above the cold reheat point with a final 583 K (590 F) feedwater temperature. Nine feedwater heaters are used. The condenser back pressure was chosen to minimize the total cost of electricity.

The heat rejection system used 24 cells of mechanical draft evaporative cooling towers. The net power from the plant would be 843 MW, representing 37.1 percent of the higher heating value (HHV) of the coal supplied to the plant.

CYCLE DESCRIPTION

A detailed plant schematic is presented in Figure B-15. State points and stream flows are shown in which the enthalpy values are referenced to 273 K (32 F) water for steam and water and to a 300 K (80 F) zero reference for air, combustion gases, and solids. The advanced feature of this power system is the use of AFB combustion to generate steam from high sulfur coal for a steam turbine cycle with a single reheat of the steam to 922 K (1200 F), with nine feedwater heaters to improve steam cycle efficiency.

Steam Turbine-Generator

Each steam turbine is contained in two shells connected in tandem with a single generator. The low-pressure stages have two parallel flows exhausting downward into a common condenser. The condenser coolant is water recirculated in a closed circuit to the evaporative cooling towers. The regenerative feedwater heating cycle has four low-pressure feedwater heaters, a deaerating feedwater heater, and four high-pressure feedwater heaters. Part of the steam exhausted from the high-pressure turbine is used in feedwater heating; the rest is returned to the AFB units to be reheated to 922 K (1200 F). Part of the steam from the reheat turbine exhaust is used for driving a boiler feedpump. The exhaust from that drive turbine is routed to the main condenser. All other pump drives are driven by electric motors and appear in the detailed account of auxiliary losses. The boiler feedpump and its drive are an integral part of the steam cycle and are fully accounted for in the heat balance for the steam turbine-generator. Three identical steam turbines are operated in parallel to aggregate the total generated output of 905 MW.

The final feedwater temperature is 583 K (590 F) for operation at the 100 percent point.

Atmospheric Fluidized Beds

The feedwater from the steam turbine cycle goes to each AFB module. It first passes through tubes submerged in the bed of the carbon burnup cell (CBC) and then through convection surfaces above the CBC bed. The heated water is then fed into the drum atop the AFB module. Downcomers feed water to the waterwalls in all of the cells. The resulting two-phase mixture with 12.9 percent steam is returned to the steam drum. The remaining evaporation is accomplished in the beds and convection space of the top two main cells. These circuits must have circulating pumps to assure adequate circulation. The superheating of throttle steam and reheating of steam is accomplished in the convection and submerged beds of the four remaining main cells as well as a small portion in the convection path of an upper cell. Steam at 16,550 kPa (2400 psig) and 811 K (1000 F) is delivered to the turbine. The reheat steam is delivered at 3410 kPa (494 psia) and 922 K (1200 F). There are four identical AFB modules operating in parallel to supply the steam required by the steam turbines.

Figure B-15. Schematic Diagram of Advanced Steam Cycle — Atmospheric Fluidized Bed

Each AFB module has six main beds rather than the two shown schematically in the figure. The injection of coal and limestone is assisted by the flow of primary air (PA) along with these solids. The main airflow (A) enters the bed in an upward flow through a perforated distribution plate that is the bottom of each fluidized bed. Most of the fluidized bed solids are the residual products of the coal-air-limestone reaction. A continual tap of these solids maintains a constant bed inventory of solids. The bed temperature of 1116 K (1550 F) results in maximum sulfur capture. It is also below the ash fusion temperature. Most of the ash will be conveyed by the gas stream as fly ash. The heat exchange surfaces within the bed material experience high overall heat transfer rates as a result of the localized agitation of the bed material. In the carbon burnup cell bed the temperature of 1366 K (2000 F) is too hot for use in superheating or reheating steam in conjunction with the high heat transfer rates. Only water tubes are located in the bed of the carbon burnup cell for the purpose of in-bed fluid dynamic stability.

The gases leaving the beds must be cooled to 661 K (730 F) for effective fly ash removal from the low-sulfur gas streams. This cooling is done by heat transfer to steam superheaters and reheaters and to evaporating surfaces as described above. The two top mainbeds use circulating pumps to maintain adequate circulation in the evaporator circuits, since the natural head would be inadequate.

The solids fed to the carbon burnup cells comprise the solids tapped from the main beds and that portion (95 percent) of the fly ash collected in the cyclone separators that receive the gas flowing from the main beds.

Flue Gas and Air Supply

The flue gas from the main beds and from the carbon burnup cells at 661 K (730 F) flow through cyclone separators that remove 95 percent of the solids burden in the gas streams. The electrostatic precipitators (ESPs) remove the remaining fine fly ash to the level required by emission standards. The hot flue gas next passes through the air preheater, where it is cooled to 394 K (250 F). The induced draft (ID) fan assists in this flow and delivers the gas at 400 K (260 F) to the stack.

Air for combustion passes through the forced draft (FD) fans. About 15 percent of that air is further boosted in pressure by the primary air fans so that it may be used to convey solids into the fluidized bed cells. The main air (A) is heated to 630 K (675 F) in the air heater and is then routed to the fluidized bed cells. The pressure rise of the forced draft fans is substantially greater than conventional practice because of the flow restrictions imposed by the fluidized beds, their perforated air distribution plates, and the cyclone fly ash separators.

Spent Solids Systems

Spent solids in the form of dry hot granular material are collected from the carbon burnup cell solids tap. Spent solids in the form of dust are collected from the carbon burnup cell cyclone separator and from the ESP. The composition of the spent solids aggregate is approximately 42 percent calcium sulfate, 24 percent unreacted lime, 31 percent ash, and 3 percent unburned carbon. The unreacted lime results from the 100 percent excess in the limestone feed rate as well as the 15 percent deficiency in sulfur capture.

Coolers are provided for the spent solids and dust to supply heated air for the drying of coal and limestone. A small amount of coal is burned in the spent solids cooler to augment this regenerative use of the sensible heat in the spent solids.

Coal and Limestone Systems

Hot air at 672 K (750 F) from the spent solids system is drawn through the feedstock dryers and storage silos by the silo air fans. The dried coal and limestone are crushed to size, blended, and then conveyed to the AFB main cells by vibration of inclined tables. Primary air is used to assist the flow from the tables down through the many injection needles or tubes in the beds.

Overview

The fluidized main beds scavenge sulfur, and the carbon burnup bed scavenges otherwise lost combustibles from fly ash and solids discharged. The subdivision into four modules ensures that malfunctions in a single AFB system would not result in total plant shutdown.

MAJOR CYCLE COMPONENTS

Components for steam power plants are specified for continuous operation, with flow rates 5 percent greater than the requirement for 100 percent power. Figure B-15 depicts the 100 percent operating point. The major component specifications as well as the balance-of-plant (BOP) components specifications are based on continuously sustaining the 5 percent margin. For the steam turbine-generator this operation is at the VWO condition of the main steam throttle control. This customary margin in all components assures purchasers that the entire system will not fall below its intended power rating because of some minor inadequacy in one or more components. The specifications for components will generally exceed by 5 percent the stated performances shown in Figure B-15 or the summaries (Tables B-26, B-27, B-31, B-32, and B-38) that follow for total plant rated performance.

The design and performance details of the AFB modules and the steam turbine-generator are considered in this section. All remaining equipment would be specified and supplied by an architect/engineer as Balance of Plant materials. Equipment lists for these items are provided below under "System Performance and Cost."

Atmospheric Fluidized Bed Modules

The major component of the heat input systems is the AFB module together with its air supply and hot gas cleanup equipment and the solids handling equipment.

In the fluidized bed combustion process, air enters a plenum at the bottom of the cell, flows up through a grid plate that is designed to distribute the air uniformly across the bed, passes through and fluidizes the bed material, which envelopes a tube bundle, exits from the bed, passes through a convection pass tube bundle located above the bed, and exits from the cell. Coal and limestone are injected into the bed through injection pipes that are arranged to distribute the coal uniformly across the bed plan area. Feeding is continuous in order to provide steady combustion conditions. Spent bed material is continually drained to provide steady bed operating levels. The surfaces submerged in the fluidized bed have exceptionally good heat transfer characteristics. In addition there is no coal-ash corrosion of the heat exchange surfaces, since the beds operate below the ash fusion temperature and provide a continuously alkaline atmosphere. Fluidized bed combustors require a combustion air supply system, a hot gas cleanup system for removing particulate material entrained in the flue gas, coal and sorbent processing and feeding systems, and a spent bed material removal system.

The spent bed material is alkaline and should be handled in a dry state. Because of its good chemical reactivity and alkalinity, it is considered a chemical byproduct of the process and could be used in a number of ways. The use of atmospheric fluidized bed dust has been reviewed for application in the neutralization of acid mine runoff, in the preparation of fertilizer, and in the preparation of alkaline scrubbing solutions for other conventional units. Because of its concentrated iron (magnetite) and alumina content, it has been considered as a feedstock for iron and aluminum manufacture. Its practical use as a feedstock for metallurgical processing will depend to some extent on a better understanding of the chemical composition as a function of size distribution in the solids products recovered from the fluidized bed boiler. No credits or costs were included for sale or disposal of spent solids off the plant site. Regeneration of spent bed material, which would reduce the quantity of waste products, was not considered in this study. It requires more development than the system considered here.

Figure B-16 shows the equipment for spent bed material removal and cooling. The spent sorbent is transported by a high-temperature vibrating conveyor to an air-fluidized bed cooler

Figure B-16. AFB Solids Handling and Hot Gas Cleanup Equipment Systems for Two Module Trains (Foster Wheeler)

which cools the material to disposable temperatures of 394 to 422 K (250 to 300 F). Heat recovered from the cooling of the spent sorbent is used to dry the raw coal and limestone by ducting the cooler's hot discharge air to the dryer units. During plant startup conditions, when hot spent sorbent is not available, the drying units obtain their heat for drying by burning coal in their furnace sections.

The Hot Gas Cleanup section of Figure B-16 shows the conventional cyclone separators and ESPs that strip elutriated bed material from the flue gases. Solid material captured in the main bed cyclones is recycled to the 1136 K (2000 F) carbon burnup cell. Material from the carbon burnup cell that is captured in its cyclone separator is removed and cooled by means of an air-fines cooler. Particulate matter captured in the ESPs is removed from the process without cooling, since the heat content of this stream is small. It is to be noted that "hot" precipitators at 661 K (730 F) are used instead of conventional 422 K (300 F) "cold" precipitators in order to compensate for the low ash resistivities that are encountered with low-temperature, low-sulfur-bearing flue gases.

The Air Supply system (Figure B-16) utilizes forced draft (FD) and induced draft (ID) fans to "push" and "pull" the combustion air through the system. Primary air boost fans are used to provide the high air pressures that are required to inject the coal and limestone into the beds. Compact air heaters are utilized to recover flue gas heat and preheat the combustion air; the tubular air heaters have no leakage, in contrast to up to 70% when conventional regenerative air preheaters are applied.

As in a conventional plant a combustion control and safety interlock system is required. However, because of the fluidized bed boiler consisting of four towers with seven combustion beds in each tower, and the need for blending and controlling the steam production of four towers, a more complicated control system is required than for a single conventional boiler. Because of the multiplicity of heat transfer circuits required in this system, a more complex startup system and control valve arrangement is required on the water and steam circuit. Further development is required for steam circuitry and control. Valves and controls for the modules only are included; items needed for a four-tower steam blending system were not included.

A process flow schematic presented as Figure B-17 summarizes the detailed heat and mass balances made for each item of equipment at the design specification point. The schematic is for one of four AFB modules. To adjust the stated mass flows for the continuous 100 percent rated operation, they should be multiplied by the factor indicated. This results in an exact match of heat to the steam cycle.

(1) STREAM FLOWS - (lb/hr)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	20A
COAL	188978	11390	187839	167177																	
STONE					415648	476219															
SOLIDS							285213	459249	286213	286306	585853	239547	37910	623763							
AIR															2147514	1739572	0	1739573	1552260	187310	
ALT	186542	0	186542	162297	143223	146825	28324	45608	28324	28324	58072	29743	3765	61946	2073440	21259	1116075	1899184	1541544	186017	17622

	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
SOLIDS								48342	24171	31531	15765	3393.6	2027	2027							
AIR	286171	116882	939195	229625	169289	59117	110172														
GAS								1784117	1784117	224667	224667	2506764	2008764	2008764	1703183	111332	159135	179797	12126	191923	39813
TOTAL								1832459	1765334	256196	126244	202773	2008764	2008764							
ALT	59181	116075	93271	22804	529	58181	0	195500	1769993	1254428	1224681	1994679	1990216	1990916	1229204	43241	166563	210813	44646	255459	30264

Flow Ratio	Condition	Heat to Steam MBtu/h	Stack (F)
1.0000	As Tabulated	1792.464 + 4.165 from Pumps	260 F
0.9935	VWO Design	1780.802 + 4.165 from Pumps	260 F
0.9498	100% Operating	1702.51 + 4.165 from Pumps	260 F
(0.9422)	100% Operating	1702.51 + 4.165 from Pumps	(185 F)

Figure B-17. Atmospheric Fluidized Bed Generator — Process Flow Schematic (Foster Wheeler)

Figure B-18 shows a design concept of one of the AFB tower modules for steam generation. This concept was developed to a sufficient level of detail to reveal major engineering problems and to permit realistic cost evaluations. The module is 6.7 m x 13.4 m x 54.9 m (22 ft by 44 ft by 180 ft) tall and weighs 2.365 Mkg (2607 tons) in operation. It includes

Figure B-18. Advanced Steam Cycle — Atmospheric Fluidized Bed Boiler —
One of Four Modules (Foster Wheeler)

evaporating, superheating, and reheating services in the beds and in the convection spaces above the beds. The tubes are of conventional materials, and tube bundles were sized to be shipped by rail. Fuel is injected into the beds through needles, each servicing about 0.79 m^2 (8.5 ft^2) of the main bed area. The bottom unit is the carbon burnup cell (CBC). There are six main cells stacked on top of the CBC. The air and flue gas ducts taper from bottom to top in proportion to the local gas flow. The heat absorption in each AFB module is shown in Figure B-19. The total heat to steam is the sum of the thermal heat transfer and the energy applied by the circulating pumps. The fluidized bed heat exchange surfaces have an overall heat transfer coefficient of $227 \text{ W/m}^2\text{K}$ ($40 \text{ Btu/hr ft}^2 \text{ F}$) in the bed. The convection surfaces above the bed have coefficients one-third to one-quarter those in the bed. A value of 74 was used in the study. Table B-22 details the heat exchanger surfaces shown in Figure B-19. Table B-23 summarizes the basic requirement for materials, which leads to Item 1 in Table B-24, where the selling prices of the AFB module are derived from the component weights. The costs of module auxiliaries are presented with the major component equipment lists later in this appendix, under "Plant Cost Estimates."

The performance evaluation for the overall boiler system shows a boiler efficiency of 88.13 percent for heat to steam divided by the total coal fired. Additional heat recovery from spent solids could completely displace coal burned to dry coal and limestone. A boiler efficiency of 88.66 percent could then be realized along with an increase in capital cost.

Prime Cycle

The major component for the prime cycle is the steam turbine-generator. The selected units were three tandem compound turbines with two-flow exhaust using .851-m (33.5-in.) last-stage buckets. A single turbine rated 905 MW, would normally be selected. In this case, the choice of three one-third-size units was made so the plant as conceptually designed could have the earliest date for commercial deployment. The 922 K (1200 F) reheat would require extensive development of cooling and materials for the turbines. An outline drawing, Figure B-20 shows the two turbine shells and the generator having an overall length of 31.4 m (103 ft). The performance of the steam turbine-generator is inseparable from many of the BOP components that are part of the prime cycle heat balance. Figure B-21 presents the heat balance for the 100 percent operating point for the entire prime cycle. The heat to steam is 2006 MJ/s (6826.7 MBtu/hr). The efficiency of the prime cycle is 45.2 percent.

The condenser back pressure of 7.8 kPa (2.3 in. Hga) resulted from an economic optimization of the turbine and heat rejection system in combination. The cooling tower specifications are given in Table B-25 insofar as they impact directly on the steam turbine prime cycle performance.

Table B-22
AFB MODULE HEAT TRANSFER — SURFACE AND PRESSURE PART DATA

BANK	CELL LOC.	SERVICE FLOW-W (mmLB/HR)	DUTY Q (mmBtu/HR)	SURFACE So (Ft ²)	φ _o (O.D.) Lo (L-Ft)	Surface Arrangement Nc CIRCUITS	S _T TRANS.	S1 LONGIT.	BC CLEAR	WT. TONS
WW	ALL	4.500 BOILING	208.5516	13042	2 1/2 (150') (108e)	340	-	-	1.25	204
B1b	A BED	11.505 BOILING	168.4118	4909	1 1/4 (6.0e)	2500	6 1/2	1	23.67	22
B1c	A CONV.	"	69.8302	17754	1 1/4 (6.2e)	2500	1 5/8	0	13.00	80
B2b	B BED	"	168.4118	4909	1 1/4	2500	6 1/2	1	23.67	22
B2c	B CONV.	"	35.3262	4651	1 1/4 (6.5e)	2500	1 5/8	0	13.00	21
(2800 lb)										
PSH1c	B CONV.	1.605 PRIMARY SUPERHEAT	34.5041	18848	1 1/2 (12')	500	3 1/4	1.500	48.00	104
PSH2c	C CONV.	"	69.8302	16492	1 1/2 (12')	500	3 1/4	.75	41.00	92
PSH3c	D CONV.	"	64.8302	16493	1 1/2 (12')	500	3 1/4	.75	41.00	92
(2700 lb)										
FSH1c	E CONV.	1.605 FINISHING SUPERHEAT	40.8747	7068	1 1/2 (12')	500	3 1/4	1.00	17.50	39
FSH1b (SET HIGH)	E	"	168.4118	7068	1 1/2 (12')	500	3 1/4	1.90	22.40	34 17
FSH2c	F	"	40.8746	7068	1 1/2 (12')	500	3 1/4	1.00	17.50	39
FSH2b	F	"	168.4118	7068	1 1/2 (12')	560	3 1/4	1.90	22.40	14 17
(2600 lb)										
RH1c	E	1.2286 PRIMARY REHEAT	28.9555	14136	1 1/2 (12')	1000	3 1/4	1.50	36.00	68
RH2c	F	"	28.9556	19848	1 1/2 (12')	1060	3 1/4	1.50	48.00	90
RH3b (SET HIGH)	C	1.2286 FINISHING REHEAT	168.4118	7068	1 1/2 (12')	750	3 1/4	1.90	22.40	18 17
RH4b	D	"	168.4118	9424	1 1/2 (12')	1000	3 1/4	1.90	30.00	23 22
ALL (600#)										
Elb	G	1.605 ECONOMIZE	53.6513	982	1 1/4 (12')	250	3 1/4	1.25	2.50	5
Elc (3000#)	G	"	84.1464	14878 (14729)	1 1/4 (12')	250	1	0	36.25	66

NOTES:

So - Installed Surface, ft²
φ_o - Tube o.d., inches
Nc - Circuits
S_T - Side spacing, inches
S1 - Back spacing, inches (staggered pitch)
BC - Bundle clearance, inches (includes one S1 for supports)

E - Economizer
PSH - Primary superheater
FSH - Finishing superheater
RH - Reheater

h - Enthalpy BTU/lb
° - Temp. °F
m - Flow million lb/hr
Q - million BTU/hr

Figure B-19. Advanced Steam — AFB Circuit Absorption Diagram for One of Four Modules

Table B-23

**AFB WEIGHT BREAKDOWN
RAW HEAT EXCHANGER SURFACE MATERIAL IN TONS
(1 Module of 4)**

SANK	ITEM	CS	T2 P2	T22 P22	TP304H	TP347H	IN601	HAST. X	MO-RE-2	TOTAL (tons)
DRUM	-	126			2					128
WW	Tubing Header & Pipe	108	180	24						204
B1	Tubing Header & Pipe	102		1	1		2			106
		98								98
B2	Tubing Header & Pipe	43				1	1			45
		329								329
PSH1	Tubing Header & Pipe	104		1	2					107
		20								20
PSH2	Tubing Header & Pipe		92	1	2					95
			13							13
PSH3	Tubing Header & Pipe		92	1	2					95
			16							16
FSH1	Tubing Header & Pipe			39	1					40
c				6						6
	Tubing Header & Pipe						17	15		32
b						11				11
FSH2	Tubing Header & Pipe			39	1					40
c				8						8
	Tubing Header & Pipe						17	15		32
b						18				18
RH1	Tubing Header & Pipe		68		2					70
		42								42
RH2	Tubing Header & Pipe		90	1	2					93
		55								55
RH3	Tubing Header & Pipe					17	18	2		37
					36					36
RH4	Tubing Header & Pipe					22	23	2		47
					57					57
E1	Tubing Header & Pipe	71			1		1		1	74
		25								25
Sum		1123	551	101	109	69	79	34	1	2067
\$/ton		2848	3144	3774	11771	15216	13300	24321	26332	4619
\$ x 10 ⁶ (mid-75)		3.198	1.732	0.381	1.283	1.050	1.051	0.827	0.026	9.548
<u>Notes:</u>										
CS	- carbon steel					TP347H	- 347 stainless steel			
T2, P2	- 1/2 chrome 1/2 molybdenum alloy steel					IN601	- Incaloy 601			
T22, P22	- 2-1/4 chrome alloy steel					HAST. X	- Hastelloy X			
TP304H	- 304 stainless steel					MO-RE-2	- Moly René-2			

Table B-24
AFB MODULE WEIGHT AND COST BASIS MID-1975

1. Heat Transfer Elements and Pressure Parts			
<u>MATERIAL</u>	<u>TONS</u>	<u>1975 \$/TON</u>	<u>1975 M\$</u>
CS	1123	2848	3.198
T2/P2	551	3144	1.732
T22/P22	101	3774	0.381
TP304H/TP3474	178	11771/15216	2.333
IN601	79	13300	1.051
Hast. X/MO-RE2	35	24321/26332	0.853
	2067	4619 avg.	9.548
2. Special AFB Items			
Injector Needles	39.10	6455	0.252
Fluidization Grilles	35.70	6528	0.233
	(2856 ft ²)	(\$82/ft ²)	
Solids Lines	72.00	3300	0.238
	(360 ft)	(\$660/ft)	
Solids Valves	8.00	13750	0.110
	(16 valves)	(6875@)	
	154.8	5512	0.833
3. Control Systems			
		<u>UNITS × \$/UNIT</u>	
Startup, Steam Valves	13.4	16 × 3000	0.048
Combustion Elements	3.5	7 × 11000	0.077
Bed Air Dampers	5.6	7 × 4400	0.031
	22.5		0.156
Control Components			0.415
			0.571
4. Miscellaneous Items			
Cell Partition, Seal	44	1590	0.070
Plates (25.73 lb/ft ²)	(3400 ft ²)	(\$20.58/ft ²)	
Flues and Ducts*	39	1430	0.056
(2.55 lb/ft ²)	(7200 ft ²)	(\$2.81/ft ²)	
Boiler Lag and Sheath	77	880	0.062
(9.615 lb/ft ²)	(16000 ft ²)	(\$3.85/ft ²)	
Buckstays and Braces, etc.	110	1100	0.121
Misc. Pipe, Springs, Joints	54	5500	0.297
	333		0.727
TOTALS: 2577 tons, 11.68 M\$			
Control 0.42M\$, 11.26 M\$ All else

Figure B-20. Preliminary Study Outline — One of Three Steam Turbine-Generators

Figure B-21. AFB Steam Cycle Heat Balance — 100% Output from Three TC2F Steam Turbine-Generators

Table B-25
COOLING TOWER PERFORMANCE

Design Heat Duty	3,739 MBtu/hr
Wet Bulb	51.5 F
Condensing at 2.3 in. Hga	105.9 F
Hot Water to Tower	100.9 F
Cold Water Return	70.2 F
Range	30.7 F
Approach	18.7 F
Water Flow	243,600 gpm
Fan Power	2.70 MW
Pump Power	4.59 MW
Cells	24
Each cell: 36 ft long, 75 ft wide, 47 ft high, 1 fan	

Materials of Construction

Steam turbines operating at design throttle steam temperatures of 811 K (1000 F) have demonstrated a high degree of reliability and utilize materials with a long history of development and service. The use of 922 K (1200 F) reheat steam will mandate additional cooling if conventional turbine materials are to be used for the reheat turbine. Significant development effort would be required to pursue the alternative of using higher temperature alloys which do not require cooling.

Two steps were taken in steam turbine-generator selection for this study to minimize the risk for an initial application. The last stages of the turbine were designated to use 6 flows to the condenser, whereas 4 flows would be sufficient to pass the total steam. As a result each section has less than two-thirds of its upper limit of steam flow, with a proportional reduction of stresses. By this selection, margin is gained to counterbalance the higher steam temperature. As a second measure, three turbine-generators, rated 302 MW each, would be used in place of a single turbine at 905 MW (905 MWe). The three units would operate precisely in unison, as if they were a single machine. This selection would reduce the diameter and the bucket height in the 922 K (1200 F) reheat sections. It was expected that these smaller ratings would be commercially available ten years before the evolution of a high-capacity 922 K (1200 F) reheat steam turbine-generator. The factors governing materials application for particular parts of the steam turbine-generator are identical with current practice.

Buckets are subjected to centrifugal forces, steam forces, vibratory forces, thermal stresses, and erosion from wet steam. Alloys are chosen on the basis of strength at operating conditions, erosion and corrosion resistance, damping properties, and ease of machinability.

Turbine rotors and wheels are subjected to bucket loadings and must have high resistance to creep and rupture and good thermal stability to resist bowing. The material is selected on the basis of yield, tensile, creep, and rupture strengths, transition temperature hardness and impact strength, and resistance to erosion and corrosion due to normal steam chemistry. Alloy steels are typically used.

Nozzle diaphragms must perform over a wide range of temperature and pressure conditions and withstand steady-state thermal and pressure loadings, differential expansion stresses, and cyclic thermal stresses. In addition the material must be fully weldable and produce sound castings. The material must also have good creep and rupture strength and be resistant to erosion and corrosion. The high-pressure shell or casing must contain the high-pressure steam and resist creep in longtime service and also be resistant to erosion and corrosion. Castability and weldability are important requirements. Alloy steels are used. Materials for valve bodies are similar to those used for shells and are selected on the same basis of creep and rupture strength, weldability, stability, and resistance to erosion and corrosion.

With periodic repair and replacement of some parts, 30 years of operation can be expected for the turbine. For the buckets, each turbine stage is analyzed for stresses and frequencies under the specific operating conditions, and allowable stresses are established from results of laboratory testing on creep, rupture, fatigue, erosion and corrosion resistance, and experience. Rotors and wheels are sized on the basis of torque, plus centrifugal and bending stresses, and are carefully analyzed for critical speeds. When major parameters are established, they are analyzed in detail for fillets, grooves, balancing provisions, and contours. Each turbine diaphragm is analyzed for stresses, and the results of extensive laboratory testing are used to establish the allowable stresses. For the shells, the analysis starts with a pressure stress calculation and then is refined for thermal stresses, with stress concentrations taken into account. The design procedure for valves likewise analyzes for stress concentration points and provides modifications to account for both steady-state and transient conditions. The thermal stresses are limited by establishing allowable rates of heating and cooling.

In the AFB, coal combustion occurs in a bed of limestone which operates at 1116 K (1550 F). The materials selected for the various temperature ranges within the AFB at 16,650 kPa (2400 psig) are carbon steel (CS) for 728 K (850 F) maximum temperature, 1/2 chrome—1/2

molybdenum alloy steel (T2) for 783 K (950 F) maximum temperature, 2-1/4 chrome alloy steel (T22) for 800 K (980 F) maximum temperature in thick sections and 866 K (1100 F) in thin sections, and 304 stainless steel (T304) for maximum temperatures. At the reduced pressure of 3790 kPa (550 psi) for reheater service, T22 would be used for 853 K (1075 F) maximum and T304 for 1011 K (1360 F) maximum. Incaloy 601, Hastelloy X, and Moly-Rene-2 would be used for reheater service to 922 K (1200 F).

Design lifetimes were based on the ASME Power Boiler Code to give an estimated 30-year life. This involves assessment of tensile strength, yield strength, creep, and rupture strength. No detailed investigation was made of corrosion, erosion, or fouling rates, and it was judged that conservative procedures for selecting boiler metals would result in the selection of metals adequate for the projected life. The rationale was that internal corrosion was not expected to be a problem and the small amount of external oxidation, sulfiding, and wastage would be compensated for by conservative design. External fouling was not considered.

These judgments are based on extensive experimental data on hot corrosion of boiler tube materials. There is in fact good reason to believe that corrosion in fluidized bed combustion systems for the lower temperature steam tubes will be much less severe than in conventional pulverized-coal-fired units. However, there could be a serious corrosion problem in the hotter components of the system.

The ash particles formed at the relatively low fluidized bed combustion temperature are soft and friable compared with the fused ash particles generated in the high-temperature pulverized coal flames of a conventional furnace. No erosion has been reported in pilot scale tests of fluidized bed combustors, so this does not appear to present a significant problem.

Fouling on boiler tubes may become a problem, depending on the ash composition of the coal, its reaction with the bed sorbent, and the operating temperature. If the problem proves to be severe, there may be ways of reducing it by modifications in operating temperatures or by the use of fuel additives.

The steam turbine will require intense development for cooling, and significant materials developments are anticipated. The fluidized bed system has potential problem areas, but new material developments are not anticipated. A principal concern is hot corrosion; it will be necessary to run tests with a variety of coals and tube materials to develop a complete understanding.

BALANCE-OF-PLANT ARRANGEMENT AND COSTS

Plot Plan

The plant arrangement on its plot is based on storage of a 60-day supply of coal and a capacity to hold ash for 15 days. A series of ponds contain runoff water from the site and provide for treatment of all water returned to the North River. The basic plot dimensions are 805 m by 483 m (one-half mile by three-tenths of a mile).

Figure B-22 shows the main plant area; the total plant area including runoff ponds (not shown) covers 437,000 m² (108 acres). Coal is received by rail and is unloaded to two conical storage piles. The compacted dead storage coal pile is 18.3 m (60 ft) high with a base measuring about 378 m (1240 ft) by 128 m (420 ft). This stores 384.7 Mkg (424,000 tons) of coal for recovery by the use of dozer tractors. Two conical live coal storage piles are provided with a base diameter of about 96 m (315 ft). These piles contain a total of 104.1 Mkg (114,700 tons) of coal, with 24.5 Mkg (27,000 tons) vibrating feeders. Limestone is stored in a single storage pile of 122.5 Mkg (135,000 tons) total capacity with 6.10 Mkg (6720 tons) available as live feed by gravity flow to the under-pile vibrating feeders. These feeders load a conveyor to the coal cascade. At that point magnetic separators remove tramp iron, and oversized coal is diverted to the crushers for size reduction prior to distribution. The coal and the limestone are then dried, passed through grinders, and blended. There are three trains of equipment from the cascade to the delivery of dried and blended feedstock. Any one of the three sets may be out of service without reducing plant output. The coal and limestone mixture is next conveyed to each of the four AFB modules. The dried and cooled spent solids produced by the AFB operations are conveyed to the 15-day ash storage bins at the lower left, for loading on railroad cars. The 24 cells of wet cooling towers are set apart from the rest of the plant in the upper right corner.

General Arrangement—Plan and Elevations

The arrangement of the four AFB modules and the turbine building is shown in Figure B-23. This arrangement made it possible to keep the steam lines short. The ground level plan shows the air path through the forced draft (FD) fan and the air preheater and then around the lower outside of the AFB to the end next to the turbine building. The 15.5 m (51 ft) level plan shows the path of the flue gas through the electrostatic precipitator (ESP), the air preheater, and the induced draft (ID) fan, and thence to the stack. The line-up of the three steam turbine-generators is also evident.

The plant elevation view through the turbine building and one AFB is presented in Figure B-24. The seven-cell stack of fluidized beds stands 58.6 m (192 ft) high. Air is fed

GENERAL ELECTRIC
PROJECT DESIGN IN FULL OPERATION

Figure B-23. General Arrangement Plan for Advanced Steam Cycle — Atmospheric Fluidized Bed

Figure B-24. General Arrangement Elevation for Advanced Steam Cycle — Atmospheric Fluidized Bed

upward from the right, and flue gas flows downward on the left side of the AFB module to the cyclone separator. The flue gas passes through the ESPs, the air heater, and the ID fan, and to the stack.

One-Line Electrical Diagram

A single-line diagram showing major electrical equipment is presented in Figure B-25. The steam turbine-generators feed two main transformers at 25 kV, and two unit transformers feeding the 13.8 kV buses. A startup transformer also may feed the 13.8 kV buses. Major electrical loads are indicated as well as the subsidiary bus bars and the emergency diesel generator.

Figure B-25. Electrical Diagram Advanced Steam Cycle—Atmospheric Fluidized Bed

CYCLE PERFORMANCE AND COST

Performance

Cycle performance concerns boiler efficiency, prime cycle efficiency, and the fraction of gross generation expended for auxiliary services. These evaluations are made at the 100

percent operating point. Table B-26 presents the gross generation, the auxiliary power losses, and the net power transmitted from the plant. The auxiliaries are 6.8 percent of the gross generation. Table B-27 gives a detailed breakdown for the auxiliary losses. Half of these are attributed to the AFB module services. The FD fan power is four times conventional values as a result of the added flow path resistances for the fluidized bed, the distribution grid plate, and the cyclone separators.

Table B-26
CYCLE ELECTRICAL OUTPUT
ADVANCED STEAM CYCLE — ATMOSPHERIC FLUIDIZED BED

Total Gross Output (MWe at 60 Hz ac)	905.0
Total Auxiliary Losses (MWe at 60 Hz ac) including Transformer Losses	61.9
Net Power Plant Output (MWe at 60 Hz ac 500 kV)	843.1

Costs—General

Costs were synthesized from major component costs, balance-of-plant (BOP) material costs, and BOP labor costs. Items made up of numerous smaller components are presented by enumeration of the total cost and unit count for each of the subcomponents. An equipment list for BOP components identifies all major items. A detailed breakdown of BOP labor man-hours and material costs completes identification of all material and construction and installation costs. Thereafter these are combined with major component costs to arrive at total plant costs.

Costs—Major Components

The steam turbine-generator costs must be considered speculative, pending more detailed evaluations as well as several years of design and development effort. A single tandem compound six-flow unit at 905 MWe would have an estimated cost at standard conditions (16,550 kPa/811 K/811 K [2400 psi/1000 F/1000 F]) of \$30.5 million; the estimated cost penalty for adding the 922 K (1200 F) reheat temperature is \$26 million, which increases the total cost to \$56.5 million. In order to foreshorten the time to commercial readiness, three

Table B-27
AUXILIARY LOSS BREAKDOWN
ADVANCED STEAM CYCLE — ATMOSPHERIC FLUIDIZED BED

ITEM	ASSUMPTIONS	NO. OF UNITS	TOTAL MW _e
Furnace			
Dust cooler fans	70" ΔP, 0.60 eff	4	0.7
Silo air fans	24" ΔP, 0.82 eff	4	0.8
FD fans	67" ΔP, 0.82 eff	4	17.4
PA fans	16" ΔP, 0.82 eff	4	0.4
ID fans	16" ΔP, 0.78 eff	4	4.7
ESP		8	3.3
Circ. pumps	27 psi, 0.85 eff	16	5.4
Solids Handling		4	0.7
			<u>33.4</u>
Turbine Auxiliaries		3	2.9
Major Pumps			
Service	A/E Estimate	2	0.9
Condensate	220 psi, 4.37 Mlb/hr	2	1.2
Circulating water	Proportion to Cooling Heat Duty	3	4.6
Water Intake	A/E Estimate	2	1.0
Solids Handling	Based on Rates and Lifts	1	1.9
"Hotel" Loads		1	8.8
Cooling Tower Fans	Proportional to Heat Duty	24	2.7
Transformers	0.5% of Gross Generation	4	4.5
			<u>4.5</u>
	TOTAL AUXILIARY POWER		61.9

units of 302 MW each were selected for this evaluation. Their aggregate cost would be \$36 million at standard conditions, and \$62 million for units for the 922 K (1200 F) reheat temperature.

The steam generator comprises four AFB modules, auxiliary units serving each AFB, conveyor and solids equipment serving pairs of AFB modules, and solids preparation equipment providing three units, any two of which can service the entire plant. Equipment lists for the AFB steam generator system are presented in Tables B-28, B-29, and B-30.

Table B-28
SOLIDS HANDLING FOR AFB — EQUIPMENT LIST AND COSTS

SUBSYSTEMS	COST (1975 \$)	PLANT REQUIREMENT	
		NUMBER	M\$
<u>Coal Drying & Crushing</u>			
1 - Dryer System-189 TPH	\$ 910,446		
1 - Coal Crusher & 2 Screens	159,250		
1 - Distribution Box	31,200		
2 - Vibrating Feeders @ 94-1/2 TPH	11,701		
2 - Surge Bins @ 7600 ft ³	59,489		
2 - Bin Activators	20,800		
2 - Weighbelt Feeders @ 94-1/2 TPH	53,101		
Section Subtotal =	\$1,245,987	3	3.74
<u>Limestone Drying & Crushing</u>			
1 - Dryer System @ 48.6 TPH	358,800		
1 - Crusher & 2 Screens	82,550		
1 - Distribution Box	11,128		
2 - Vibrating Feeders @ 24.3 TPH	7,800		
2 - Surge Bins	22,256		
4 - Bin Activators	26,000		
2 - Air Lock Valves	6,501		
2 - Vibrating Feeders	7,800		
2 - Weighbelt Feeders @ 24.3 TPH	17,906		
Section Subtotal =	540,741	3	1.62
<u>Coal & Limestone Blending & Feeding</u>			
2 - Blenders @ 115 TPH	130,000		
14 - Air Lock Valves	36,983		
14 - Vibrating Feeders	91,002		
56 - Vibrating Tables	657,120		
Section Subtotal =	915,120	3	2.74
<u>Spent Bed Material Cooling</u>			
2 - Air Lock Valves @ 15 TPH	27,300		
2 - Surge Bins and Cooler	41,600		
4 - Air Lock Valves @ 30 TPH	67,600		
2 - Solids Cooler & Cyclones	312,000		
Section Subtotal =	448,500	2	0.90
<u>Solids Handling Controls</u>			
1 - Control System			
Section Subtotal =	149,058	3	0.45
Subtotal for Solids Handling			9.45

Table B-29
HOT GAS CLEANUP AND AIR SUPPLY FOR AFB-EQUIPMENT LIST AND COSTS

SUBSYSTEMS		COST		PLANT REQUIREMENT	
HOT GAS CLEANUP & AIR SUPPLY		(1975 \$)		NUMBER	M\$
4 - Bed Cyclone Units		\$ 392,391			
12 - Cyclone Air Lock Valves		78,000			
4 - Fines Injection Systems		260,000			
2 - CBC Cyclone Units		73,060			
2 - CBC Cyclone Air Lock Valves		25,480			
2 - Surge Bins @ Dust Cooler		40,404			
2 - Coolers for CBC dust		260,000			
4 - Cooler Air Lock Valves		50,960			
4 - Electrostatic Precipitators		2,406,103			
2 - Air Preheaters (compact tubular type)		2,676,000			
2 - ID Fans & Motors		911,587			
2 - FD Fans & Motors		929,234			
2 - PA Fans & Motors		90,813			
Section Subtotal =		\$ 8,194,032		2	16.39

Table B-30
TOWER COMPONENTS FOR AFB-EQUIPMENT LIST AND COSTS

SUBSYSTEMS		COST		PLANT REQUIREMENT	
ITEMS		(1975-M\$)		NUMBER	M\$
Heat Exchange and Pressure Parts		9.624			
Injector and Air Parts of AFB		0.833			
Control System		0.571			
Flues, Ducts, Insulation, etc.		0.627			
Circulating Pumps		0.847			
		12.502		4	50.01
Total for Modules, excluding Solids Handling				4	66.40
Total Above Without Electrostatic Precipitators				4	61.59

Major Component Characteristics

Table B-31 presents the characteristics of the AFB module heat exchange and pressure containment parts. The 88.14 percent efficiency represents heat to steam divided by the HHV of all the coal that is fired in the plant. The average heat flux is high compared with conventional boilers. However, the peak heat flux is very much less than peak values for conventional boilers. As a result, the AFB heat exchange surfaces are expected to have a far longer service life than the hottest parts of conventional furnaces and boilers.

Table B-31
HEAT EXCHANGER CHARACTERISTICS
ADVANCED STEAM CYCLE — ATMOSPHERIC FLUIDIZED BED

HEAT EXCHANGER	NO. OF UNITS	VESSEL SIZE OR TYPE	OUTPUT OR DUTY PER UNIT (MBtu)	EFFICIENCY	UNIT SURFACE AREA (ft ²)	UNIT WEIGHT (FOB) (MLb)	UNIT COST (FOB) (M\$)	HEAT FLUX AVERAGE (Btu/hr ft ²)
AFB Module	4	76' × 33' × 178'	1707	88.14%	190560	5.21	9.6	8960

*Heat exchange surfaces and pressure parts only

Equipment List—Balance of Plant

The BOP equipment and its specifications are listed in Table B-32. The specifications are based on VWO steam turbine flow rates. In addition, electric motor drives for fans and pumps anticipate a further margin of 10 percent flow, 20 percent pressure rise, and 30 percent power. As a result, the motors are sized for continuous duty at levels well above the 100 percent plant operating point.

Capital Costs—Balance of Plant

Table B-33 presents the architect/engineer's detailed breakdown of the direct manual field labor in thousands of man-hours, and of BOP material cost in thousands of dollars for each major category of the balance of plant. In using these data, an average hourly field labor rate of \$11.75 in mid-1975 dollars converts man-hours to dollars. In tables where field indirect labor is allocated to individual items rather than the total labor for the job, it is apportioned as 90 percent of the direct field labor, which is equivalent to \$10.58 per hour.

Table B-32

BALANCE-OF-PLANT EQUIPMENT LIST
ADVANCED STEAM PLANT — ATMOSPHERIC FLUIDIZED BED

EQPT. NO.	SERVICE	DESCRIPTION
C-1	Coal Conveyor Belt	60 in wide, 344 ft long, 3,000 tph, 375 hp
C-2	Coal Conveyor Belt	60 in wide, 575 ft long, 3,000 tph, 660 hp
C-3	Coal Conveyor Belt	60 in wide, 190 ft long, 3,000 tph, 435 hp
C-4	Coal Conveyor Belt	42 in wide, 1,000 ft long, 500 tph, 150 hp
C-5	Coal Conveyor Belt	42 in wide, 610 ft long, 500 tph, 115 hp
C-6	Limestone Conveyor Belt	60 in wide, 375 ft long, 3,000 tph, 95 hp
C-7	Limestone Conveyor Belt	36 in wide, 1,035 ft long, 125 tph, 21 hp
C-8	Limestone Conveyor Belt	36 in wide, 830 ft long, 125 tph, 27 hp
C-9	Feed Cascade System:	
	2 Conveyor Belts	24 in wide, 540 ft long, 190 tph
	3 Conveyor Belts	24 in wide, 170 ft long, 190 tph
	12 Conveyor Belts	24 in wide, 30 ft long, 190 tph
	18 Bucket Elevators	60 ft average height, 190 tph
	2 Conveyor Belts	18 in wide, 540 ft long, 48 tph
	3 Conveyor Belts	18 in wide, 140 ft long, 48 tph
	15 Conveyor Belts	18 in wide, 30 ft long, 48 tph
	15 Bucket Elevators	60 ft average height, 48 tph
	2 Conveyor Belts	36 in wide, 140 ft long, 240 tph
	4 Conveyor Belts	24 in wide, 300 ft long, 119 tph
	4 Conveyor Belts	24 in wide, 110 ft long, 119 tph
	4 Bucket Elevators	200 ft high, 119 tph
C-10	Ash Residue Removal System:	
	2 Conveyor Belts	24 in wide, 600 ft long, 64 tph
	1 Conveyor Belt	36 in wide, 1,840 ft long, 128 tph
	1 Conveyor Belt	36 in wide, 420 ft long, 128 tph

Table B-32 (Cont'd)

EQPT. NO.	SERVICE	DESCRIPTION
C-11	Six Vibrating Feeders for Car Unloading	Rating 0-750 tph
C-12	Coal Belt Scale	0-3,000 tph, 60 in Belt
C-13	Coal and Limestone Sampling System	0-3,000 tph, 60 in Belt
C-14	Coal Lump Crusher (3 req'd.)	0-10 tph, 10 in Lumps
C-15	Limestone Lump Crusher (3 req'd.)	0-10 tph, 10 in Lumps
C-16	Magnetic Coal Cleaner (3 req'd.)	500 tph
C-17	Magnetic Limestone Cleaner (3 req'd.)	125 tph
C-18	Coal and Limestone Dust Control System	four 6000 cfm Bag Type Dust Collectors
C-19	CO ₂ Fire Protection System	Adequate to Service Item C-18 Bag-house
C-20	Vibrating Feeders for Limestone Pile (4 req'd.)	0-100 tph
C-21	Vibrating Feeders for Coal Piles (8 req'd.)	0-200 tph
C-22	Ash Storage Silos (6 req'd.)	Total Volume 2,206,800 ft ³ 80 ft dia x 75 ft high
C-23	Eight Coal Silos	375 tons each
C-24	Two Limestone Silos	325 tons each
<u>2. Electrical Systems</u>		
E-1	Main Transformer (2 req'd.)	500 MVA, FOA 65 C, 24/500 kV, 3Ø, 60 Hz
E-2	Unit Auxiliary Transformers	27/36/45 MVA, 65 C, OA/FA/FOA, 24/13.8K/, 3Ø, 60 Hz
E-3	Emergency Diesel Generator	1000 kW, 3Ø, 60 Hz, 480, V, 0.8 PF
E-4	Startup Transformer	20/26.5/33 MVA, OA/FOA/FOA, 65°C, 500/13.8 kV, 3Ø, 60 Hz
E-5	Miscellaneous 480 V LCC Transformers (17 req'd.)	1680 kVA, OA, 65°C, 13.8 kV/ 480V/277V, 3Ø, 60 Hz

Table B-32 (Cont'd)

EQPT. NO.	SERVICE	DESCRIPTION
E-6	4.16 kV Boiler Auxiliary Transformers (2 req'd.)	4000 kVA, OA, 65°C, 13.8/4.16kV, 3Ø, 60 Hz
E-7	4.16 kV LCC Transformers (2 req'd.)	5500 kVA, OA, 65°C, 13.8/4.16kV, 3Ø, 60 Hz
<u>3. Main Fluid Systems</u>		
F-1	Main Condenser (3 req'd.)	1.39 × 10 ⁵ ft ² heat exchange surface. Design conditions, 2.3 in. Hg, 106°F, 1.09 × 10 ⁶ lb/hr. Two pass, 40 ft long tubes with 15,600 at 1 in. dia. Circulating water temperature rise of 30.7°F.
F-2	Piping:	
	<u>Service</u>	<u>Inside Diameter</u> <u>Minimum Wall Thickness</u>
	Circulating Water	130 in.
	Main Steam	10.0 in. 1.87 in.
	Boiler Feedwater	10.0 in. 1.50 in.
	Cold Reheat	18.0 in. 0.41 in.
	Hot Reheat	24.0 in. 0.84 in.
F-3	Feedwater Heaters	
	<u>Shell Press./Temp. (psia/ F)</u>	<u>Tube Press./Temp. (psia/ F)</u> <u>Steam Flow 100% (M lb/hr)</u> <u>Heat Transfer Area (ft²)</u>
	LP No.1 150	210/153 4.37 16,900
	LP No.2 10/190	210/186 4.37 11,460
	LP No.3 17/224	210/219 4.37 11,530
	LP No.4 62/295	210/292 4.37 22,020
	No.5 Deaerator 127/346	- 6.15 -
	IP No.6 219/390	3018/352 6.15 17,970
	HP No.7 532/473	3018/473 6.15 23,410
	Harp No.8 904/540	3018/543 6.15 31,590
	Harp No.9 1400/587	3018/590 6.15 22,400
EQPT. NO.	SERVICE	DESCRIPTION
F-4	Main Condenser Pumps and Motors (2 req'd.)	Vertical Centerline 4,375 gal/min, 650 hp, motor-driven, 410 ft TDH
F-5	Booster Pumps & Motors (not req'd.)	

Table B-32 (Cont'd)

EQPT. NO.	SERVICE	DESCRIPTION
F-6	Main Boiler Feed Pumps and Turbine Drivers (3 req'd.)	6,860 gal/min, 13,400 hp, 7,760 ft TDH
F-7	Main Circulating Water Pumps and Motors (3 req'd.)	86,250 gal/min, 1,828 hp, 75 ft TDH
F-8	Cooling Tower (24 cells)	235,250 gal/min
F-9	Exhaust Stacks (2 req'd.)	17 ft i.d., 470 ft high

Table B-33
BALANCE-OF-PLANT ESTIMATE DETAIL
ADVANCED STEAM PLANT — ATMOSPHERIC FLUIDIZED BED

	DIRECT MANUAL FIELD LABOR (MH 1,000s)	BALANCE-OF- PLANT MATERIAL (\$1,000s)
1. <u>AFB Steam Generators</u>		
1.1 Steam Generator Erection		
Erect only (supply by others): includes heat transfer surface and pressure parts; buckstays, braces, and hangers; attached flue and duct; fluid bed com- ponents; control equipment and valves; miscellaneous piping and small valves; insulation for above	343	
- Supply and erect: includes support steel for above; access steel; miscellaneous mate- rials and labor operations	158	3,020
1.2 Steam Generator Auxiliaries		
- Erect only (supply by others): includes P.A. fans; F.D. fans, I.D. fans; air preheaters; coal and limestone feed tables; pipes; and air lock valves	70	100
- Supply and erect: includes external flue and duct; support steel for ductwork; in- sulation for external ductwork	198	2,570
1.3 Stack Gas Cleanup		
- Erect only (supply by others): includes cyclones and electro- static precipitators	82	
- Supply and erect: includes support steel for cy- clones and precipitators	14	610
	<u>865</u>	<u>6,300</u>
2. <u>Turbine Generator</u>		
- Install only (supply by others): includes 883 MWe steam turbine; generator; exciter; auxiliary equipment; integral steam and auxiliary piping; insulation; miscellaneous labor operations	292	225

Table B-33 (Cont'd)

	DIRECT MANUAL FIELD LABOR (MH 1,000s)	BALANCE-OF- PLANT MATERIAL (\$1,000s)
3.0 Process Mechanical Equipment		
3.1 Boiler Feedwater Pumps	10	3,200
- Supply and install: includes turbine-driven main feed- water pumps and drivers (3 @ \$940,000 ea.*);		
3.2 Main Circulating Water Pumps	3	790
- Supply and install: includes main circulating water pumps and motors (3 @ \$250,000 ea.*)		
3.3 Other Pumps	5	670
- Supply and install: includes condensate pumps and motors (2 @ \$100,000 ea.*) and other pumps and drivers not listed elsewhere		
3.4 Main Condenser*	31	2,460
- Supply and install: includes shells; tubes; air ejectors		
3.5 Heaters, Exchangers, Tanks, and Vessels	11	3,150
- Supply and install: includes feedwater heaters (8); deaerating heater and storage tank; miscellaneous heaters and exchangers; tanks and vessels		
3.6 Stacks and Accessories	110	1,700
- Supply and erect: includes concrete stacks and liners*; lights and marker painting; hoists and platforms; stack foundations		
3.7 Turbine-Hall Crane	3	420
- Supply and erect: includes crane and accessories		
3.8 Coal Handling		
- Erect only (supply by others): includes coal dryers (3); support and access steel for dryers; coal grinders (3); screens at grinders	22	10
*Based on suppliers' oral budgetary quotations		

Table B-33 (Cont'd)

	DIRECT MANUAL FIELD LABOR (MH 1,000s)	BALANCE-OF- PLANT MATERIAL (\$1,000s)
3.0 <u>Process Mechanical Equipment</u> (Cont'd)		
- Supply and erect: includes railcar dumping equipment dust collectors; primary crushing equipment; belt scale; sampling station; magnetic cleaners, mobile equipment; conveyors to pile; re- claiming feeders; conveyors to cas- cade; coal cascade; conveyors and bucket elevators to dryers and grinders; recirculating conveyors at grinders; conveyors to blenders	73	5,700
3.9 Limestone Handling		
- Erect only (supply by others): includes limestone dryers (3); support and access steel for dryers; limestone grinders (3); screens at grinders; limestone surge bins at AFB modules	11	10
- Supply and erect: includes magnetic cleaners; con- veyor to limestone pile; reclaiming feeders; conveyors to cascade; lime- stone cascade; conveyors and bucket elevators to dryers and grinders; recirculating conveyors at grinders; conveyors to blenders; pneumatic transport feeders, hoppers, blowers and piping to AFB modules	45	1,960
3.10 Coal and Limestone Blend Handling		
- Erect only (supply by others): includes blenders (3); surge bins; bin unloader and feeders	4	10
- Supply and erect: includes conveyors and bucket ele- vators to AFB modules	13	920
3.11 Spent Solids Handling		
- Erect only (supply by others): includes high temperature vibrating feeders and conveyor to solids cooler	6	10

Table B-33 (Cont'd)

	DIRECT MANUAL FIELD LABOR (MH 1,000s)	BALANCE-OF- PLANT MATERIAL (\$1,000s)
3.0 Process Mechanical Equipment (Cont'd)		
- Supply and erect: includes fly ash handling system for precipitators and air preheater; solids cooler accessories and bucket elevator; ash conveyors; ash storage silos (6) with feeders; unloaders and foundations, railcar loading equipment	93	4,480
3.12 Cooling Towers*		
- Supply and erect: includes mechanical draft towers with fans and motors	49	2,135
3.13 Other Mechanical Equipment	30	1,720
- Supply and install: includes water treatment and chemical injection; air compressors and auxili- aries; fuel oil ignition and warm-up; screenwell; miscellaneous plant equip- ment, equipment installation		
	519	29,345
4.0 Electrical		
4.1 Main Transformers*	4	2,030
4.2 Other Transformers* and Main Bus	15	1,160
- includes startup transformer; station service transformers; generator main bus		
4.3 Switchgear and Control Centers	37	3,020
- includes switchgear and load centers; motor control centers; local control stations; distribution panels, relay, and meter boards		
4.4 Other Electrical Equipment	428	2,400
- includes communications, grounding; cathodic and freeze protection; lighting; pre-operational testing		
*Based on suppliers' oral budgetary quotations		

Table B-33 (Cont'd)

	DIRECT MANUAL FIELD LABOR (MH 1,000s)	BALANCE-OF- PLANT MATERIAL (\$1,000s)
4.0 <u>Electrical</u> (Cont'd)		
4.5 Auxiliary Diesel Generator	2	110
- includes diesel generator, batteries, and associated dc equipment		
4.6 Conduit, Cable Trays, Wire, and Cable	564 1,050	3,580 12,300
5.0 <u>Civil and Structural</u>		
5.1 Concrete Substructures and Foundations	360	2,975
- includes turbine building sub- structure; AFB base mats; coal, limestone and ash, handling foun- dations, pits and tunnels; mis- cellaneous equipment foundations; auxiliary buildings and substruc- tures; miscellaneous concrete		
5.2 Superstructures	337	9,630
- includes turbine building and auxiliary yard buildings		
5.3 Earthwork	136	310
- includes building excavations; coal, limestone and ash-handling excava- tions; circulating water system excavations; AFB foundation excava- tions; miscellaneous foundation ex- cavations; and dewater and piling		
5.4 Cooling Tower Basin Circulating Water System	110	1,748
- includes circulating water pumps pads, riser and concrete envelope for pipe; cooling tower basin; circulating water pipe; cooling tower miscellaneous steel and fire protection		
5.5 AFB Boiler Enclosures	55	2,170
- includes structural steel; un- insulated walls and roofing; building services; and elevators		
	998	16,833

Table B-33 (Cont'd)

	DIRECT MANUAL FIELD LABOR (MH 1,000s)	BALANCE-OF- PLANT MATERIAL (\$1,000s)
6.0 Process Piping and Instrumentation		
6.1 Steam and Feedwater Piping	76	5,840
- includes main steam; extraction steam; hot reheat; cold reheat, feedwater and condensate large piping, valves, and fittings		
6.2 Other Large Piping	165	2,670
- includes auxiliary steam; process water; auxiliary systems		
6.3 Small Piping	85	760
- includes all piping, valves and fittings of 2 inch diameter and less		
6.4 Hangers and Miscellaneous Labor Operations	245	920
- includes all hangers and supports; material handling; scaffolding; miscellaneous labor operations		
6.5 Pipe Insulation	40	474
6.6 Instrumentation and Controls	<u>115</u>	<u>2,640</u>
	726	13,304
7.0 Yardwork and Miscellaneous		
7.1 Site Preparation and Improvements	38	10
- includes soil testing; clearing and grubbing; rough grading; finish grading; landscaping		
7.2 Site Utilities	5	50
- includes storm and sanitary sewers and nonprocess service water		
7.3 Roads and Railroads	27	750
- includes railroad spur and roads, walks, and parking areas		
7.4 Yard Fire Protection, Fences, and Gates	52	600
7.5 Water Treatment Ponds	12	10
- includes earthwork; compacted clay lining; offsite pipeline		
7.6 Lab, Machine Shop, and Office Equipment	<u>1</u>	<u>280</u>
	135	1,700

Plant Cost Estimates

The installed costs of major system components are detailed in Table B-34. Those elements related to heat release—the coal and solids handling equipment, the AFB furnace modules, and the ESPs—represent a total of \$112 million. The steam turbine-generator along with its feedwater heaters and pumps is 72 percent of that amount.

Table B-34
MAJOR COMPONENT AND SUBSYSTEM CAPITAL COST SUMMARY
ADVANCED STEAM — ATMOSPHERIC FLUIDIZED BED

MAJOR COMPONENT OR SUBSYSTEM	NO. OF UNITS	COST/UNIT (FOB) (M\$)	COMPONENT OR SUBSYSTEM COSTS (FOB) (M\$)	BOP MATERIALS (M\$)	SITE LABOR (DIRECT + INDIRECT) (M\$)	TOTAL INSTALLED COST (M\$)
Fuel Handling and Preparation						
Coal and solids handling	3	—	9.45	13.10	5.96	28.51
Prime Cycle						
Steam turbine-generator	3	20.67	62.00	0.10	2.90	65.00
AFB furnace modules	4	12.50	50.01	7.66	18.40	76.27
Electrostatic precipitators	8	0.60	4.81	0.61	2.14	7.56
Cooling towers	—	—	—	3.88	3.55	7.43
Pumps, heat exchangers, stacks	—	—	—	11.97	3.80	15.77
Piping, etc.	—	—	—	13.30	16.21	29.51

The total plant costs, using the architect/engineer's categories, are presented in Table B-35. The home office and fee of 15 percent is applied only to the BOP costs. A contingency of 20 percent of all prior costs is applied to cover expected costs not specifically included in the original estimating process. The total plant cost is \$417 million.

NATURAL RESOURCES AND ENVIRONMENTAL INTRUSION

The natural resources required for this plant are presented in Table B-36. Total water withdrawals would be 0.63 m³/Gj (0.60 gal/kWh) with 0.17 m³/Gj (0.16 gal/kWh) returned from cooling tower blowdown and plant general use after appropriate water treatment. The coal usage relates directly to boiler efficiency, steam turbine cycle efficiency, and the proportion of generated power diverted for auxiliary requirements.

The environmental intrusions are enumerated in Table B-37. The sulfur emissions are comfortably under the current limit, while the nitrogen oxide emissions are less than half the

Table B-35

**BALANCE-OF-PLANT CAPITAL COST BREAKDOWN
ADVANCED STEAM CYCLE — ATMOSPHERIC FLUIDIZED BED**

CATEGORIES	COMPONENTS	COSTS (M\$)			TOTAL
		DIRECT LABOR	INDIRECT FIELD	MATERIALS	
1.0 Steam Generators	66.40	10.16	9.15	6.30	92.01
2.0 Turbine Generator	62.00	3.43	3.09	0.23	68.75
3.0 Process Mechanical Equipment	9.45	6.10	5.49	29.35	50.39
4.0 Electrical		12.34	11.10	12.30	35.74
5.0 Civil and Structural		11.73	10.55	16.83	39.11
6.0 Process Piping and Instrumentation		6.53	7.68	13.30	29.51
7.0 Yardwork and Miscellaneous		1.59	1.43	1.70	4.72
	137.85	53.88	48.49	80.01	320.23
A/E Service and Contingency					96.88
TOTAL ESTIMATED PLANT COST (1975\$)					417.11

Table B-36

**NATURAL RESOURCE REQUIREMENTS
ADVANCED STEAM CYCLE — ATMOSPHERIC FLUIDIZED BED**

RESOURCE	VALUE
Sorbent (lb/kWh)	
Limestone	0.219
Coal (lb/kWh)	0.852
Water, total (gal/kWh)	
Cooling	
Evaporation	0.444
Blowdown	0.137
Plant general use	0.018
Condensate makeup	0.0
Total Land (acres/100MW)	
Main plant	12.4
Disposal land	0.0

current standard. The major heat rejection is from the cooling tower. The total heat rejected includes the stack loss, loss from hot spent solids, and in-plant thermal energy from motors and other auxiliaries.

Table B-37
ENVIRONMENTAL INTRUSION
ADVANCED STEAM CYCLE — ATMOSPHERIC FLUIDIZED BED

<u>Emissions</u>	INPUT (lb/MBtu)	OUTPUT (lb/kWh)
SO _x	1.028	0.0095
NO _x	0.270	0.0025
HC		
CO	0.040	0.00037
Particulates	0.099	0.00091
<u>Thermal Pollution</u>		(Btu/kWh)
Heat Rejected-Cooling Towers		4441
Heat Rejected-Stack		950
Heat Rejected-Total		5687
<u>Wastes</u>	(lb/kWh)	(Mlb/day)
Spent Solids Conglomerate	0.282	.69
42% calcium sulfate		
31% ash		
24% unreacted lime		
3% carbon		
Water Discharge	1.28	25.8

The spent solids contain appreciable amounts of unreacted lime as a result of 100 percent excess of limestone feed and the 15 percent of sulfur that is not reacted. There are economic incentives which make it advisable to consider on-site recycling of the spent solids to separate the sulfur and recycle the lime.

SUMMARY OF PERFORMANCE AND COST

Table B-38 conveniently summarizes the system performance and cost effects. The plant overall efficiency of 37.1 percent is lower than the steam cycle thermodynamic efficiency; this is due to the effects of boiler efficiency and auxiliary consumption of generated electricity. The plant capital cost of 542 \$/kW (1975 \$) was based on a 5.5-year construction time, with the plant entering service in the year 2000.

Table B-38

SUMMARY PERFORMANCE AND COST
ADVANCED STEAM CYCLE — ATMOSPHERIC FLUIDIZED BED

PARAMETER	VALUE
Net Power Plant Output (MWe at 60 Hz 500 kV)	843.1
Thermodynamic Efficiency (%)	45.2
Power Plant Efficiency (%)	37.1
Overall Energy Efficiency (%)	37.1
Coal Consumption (lb/kWh)	0.852
Total Wastes (lb/kWh)	0.202
Plant Construction Time (yr)	5.5
Total Estimated Plant Cost (1975 dollars)	417.1 M\$
Plant Cost Estimate in Year of Construction Start	1424.2 M\$
Escalation and Interest During Construction	780.5 M\$
Capital Cost in Year 2000, When Plant Enters Service	2204.7 M\$
Capital Cost De-escalated to 1975 Dollars	456.7 M\$
Cost per Installed kW (1975 dollars)	542 \$/kW
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)	
Capacity Factor	0.70 0.40 0.15
Capital	15.9 27.8 74.2
Fuel	20.8 20.8 20.8
O&M	3.5 3.7 4.7
Total	40.2 52.3 99.7

The cost of electricity was based on the stated capacity factors and used a fixed charge rate of 18 percent on capital. The fuel cost used is 0.89 \$/GJ (0.94 \$/MBtu) (1975 cost) for the Illinois No. 6 coal; this is levelized over 30 years as described in Section 3. The operating and maintenance costs were derived from 1975 values and multiplied by 1.88 to produce the 30-year levelized contribution to the cost of electricity.

For the operating labor content it was estimated that a staff of 45 people of various skills would suffice (a normal plant staff includes numerous maintenance personnel whose costs are included in other accounts). At an average rate of \$20,000 per year including fringe benefits and overhead, the annual payroll charges would total \$900,000/year. This yields a fixed O&M charge of 1.06 \$/kWyr before levelization. Operating consumables were estimated as 0.77 mill/kWh of which 0.55 mill/kWh accounts for limestone costs at \$5 per ton. The balance-of-plant maintenance was 0.38 mill/kWh. The steam turbine-generator and its auxiliaries

account for 0.28 mill/kWh and the AFB 0.21 mill/kWh. The electrostatic precipitators and water intake and treatment account for 0.04 mill/kWh. The total variable O&M charge is therefore 1.68 mills/kWh before levelization.

The cost of the advanced steam power plant would be reduced approximately 9 percent if the reheat temperature for steam had been conventional. The cost would have been reduced an additional 9 percent if the AFB modules were of a once-through supercritical steam type rather than the subcritical type requiring boiling in the steam generating tubes. The overall change in net station efficiency for these changes would increase the fuel costs. The overall effect would be a reduction of 2 mills/kWh in the cost of electricity at a capacity factor of 0.70.

AFB STEAM PLANT ALTERNATIVE (185 F STACK)

An alternative configuration for the AFB modules was investigated wherein a larger air preheater would reduce the stack temperature to 358 K (185 F). Such an alternative is feasible because the concentration of sulfur products in the flue gas is so low that there is no danger of reaching the dew point in the flues or the stack.

Figure B-17 indicates the gas flow and temperatures for this alternative for one AFB module. The boiler efficiency, including the effect of the circulating pump work added, becomes 90.03 percent as compared with the former value of 88.14 percent. This improvement has been achieved not only by the reduced stack loss but also by elimination of burning coal to assist in drying the coal and limestone.

For the same heat to steam as before (which retains the former basis for sizing heat exchange surface requirements and other basic AFB components) there would be a slight reduction in airflow. The net effect at the 100 percent operating point is that the auxiliary power draw for fans and pumps is virtually unchanged. The cost of AFB auxiliary components would increase \$7.3 million. The effect would be an increase of \$9.6 million in capital cost de-escalated to 1975 dollars.

Comparisons of this alternative to the base case are presented in Table B-39. It is evident that the increased plant efficiency is achieved at a reduced total cost of electricity.

Table B-39
COMPARISON OF HIGH EFFICIENCY AFB ALTERNATIVE

PLANT PARAMETER	BASE CASE	ALTERNATIVE
Stack Temperature	260 F	185 F
Boiler Efficiency	88.14%	90.03%
Plant Cost	645.7 M\$	659.3 M\$
Overall Efficiency	37.1 %	37.9%
Gross Generation	905 MW	905 MW
Net Station Output	843.1 MW	843.1 MW
Plant Cost per kW(1975\$)	542 \$/kW	553 \$/kW
Levelized Cost of Electricity at 70% CF (mills/kWh)		
Capital	15.9	16.2
Fuel	20.8	20.4
O&M	<u>3.5</u>	<u>3.5</u>
Total	40.2	40.1

B.3 DEVELOPMENT PLANS

Development plans are presented in this section for the two cycles described in Appendixes B.1 and B.2. These cycles are similar in many respects to those considered in the Energy Conversion Alternatives Study (ECAS) (Ref. B-12), and the plans presented here are adaptations and extensions of this previous work.

OPEN CYCLE GAS TURBINE COMBINED—WATER COOLED—LOW Btu GASIFIER

The ECAS development plan for a water cooled turbine burning semiclean liquid fuel is summarized in Appendix C (Cycle F). The plan outlined below is identical in the tasks dealing with the gas turbine cooling system. Changes have been made to account for the low-Btu combustor development, and additional effort has been specified for tasks aimed at developing the coal gasifier and gas cleanup subsystems.

Table B-40 lists the technical problems which must be solved to make this cycle commercially available.

Figure B-26 shows schematic diagrams of the major test facilities required, and Figure B-27 describes the sequence of testing with decision points and possible alternate paths for the development plan.

Figure B-28 summarizes the scheduling and cost estimates for this development program. The demonstration plant cost includes interest during construction and a 20 percent learning factor on the cost of advanced technology items, such as the gasifier vessels. This is consistent with the practice followed in the Energy Conversion Alternatives Study. Costs are quoted in 1975 dollars, and the schedule starts in mid-1975.

ADVANCED STEAM (16550 kPa/811 K/922 K [2400 psi/1000 F/1200 F]) — ATMOSPHERIC FLUIDIZED BED

The Energy Conversion Alternatives Study development plan (Ref. B-12) for a supercritical steam-AFB plant is summarized in Appendix C (Cycle A). The plan refers to the single AFB module and 200 MW steam turbine currently being evaluated by TVA, and includes the pilot plant operation of an AFB in progress at Rivesville, West Virginia.

The plan evaluated in this section differs from the foregoing in several ways, and it includes additional effort beyond that which would be required for the supercritical cycle with an AFB furnace. The primary differences are the higher temperature reheat (922 K vs 811 K [1200 F vs 1000 F]) and the change to a lower pressure level (16550 kPa vs 24130 kPa [2400 psi vs 3500 psi]). The reheat will require some additional materials development, and the lower

Table B-40
TECHNOLOGY ISSUES
OPEN CYCLE GAS TURBINE COMBINED — WATER COOLED —
LOW BTU GASIFIER

Water Cooled Turbine
<p>Demonstrate ability to distribute water to turbine buckets, control flow, and minimize erosion caused by water flow.</p> <p>Develop understanding of heat transfer in cooling passages. This is a two-phase process in a high acceleration environment. Experimental and analytical work are required to develop the predictive capability needed for design.</p> <p>Development of bucket and nozzle manufacturing processes and nondestructive testing procedures for designs which optimize heat transfer, strength, and corrosion resistance.</p> <p>Development of designs, materials, and manufacturing techniques for ceramic combustor, transition piece, and first-stage nozzle.</p> <p>Development of high pressure ratio compressor; 16:1 ratio is not currently available on a single spool for industrial applications.</p> <p>Development of a low Btu gas combustor to operate at high temperatures while maintaining acceptable emissions of NO_x.</p>
Gasifier and Gas Cleanup System
<p>Demonstrate operation with caking and low ash fusion temperature coals (without pretreatment) in a full scale gasifier with low steam-to-air ratios.</p> <p>Demonstrate low ammonia generation.</p> <p>Demonstrate separation of heavy tars and phenols.</p> <p>Demonstrate heavy tar recycle and use of coal fines.</p> <p>Demonstrate sulfur and particulate removal.</p> <p>Demonstrate prevention of droplet entrainment in resaturation of cleaned gas with oils, phenols and condensate.</p> <p>Demonstrate control strategy for integrated system including gasifier, cleanup system, gas turbine, and steam turbine.</p>

PHASE II COMPONENT DESIGN AND TECHNOLOGY DEVELOPMENT

PHASE IV PILOT PLANTS

PHASE V DEMONSTRATION PLANT

Figure B-26. Experimental Facilities — Open Cycle Gas Turbine Combined — Water Cooled — Low-Btu Gasifier

pressure requires parallel recirculation boiling circuits instead of the once through design specified for the supercritical cycle. The development plan for this cycle has been scheduled and costed as if each facility were revised or added on as the current commitments for the facilities are fulfilled.

Three facilities are utilized in this plan. Facility "A" is a small AFB test bed (0.46 x 1.83 m [1.5 x 6 ft]) in which heat transfer and high temperature soak tests may be made at low risk and low cost.

Figure B-27. Logic Flow Diagram: Open Cycle Gas Turbine - Combined Water Cooled - Low Btu Gasifier

Figure B-28. Development Plan Schedule: Open Cycle Gas Turbine Combined — Water Cooled — Low Btu Gasifier

Facility "B" has two AFB main cells each with plan dimensions of 1.83 x 1.83 m (6 x 6 ft). Adaptation of the facility to this development plan is illustrated in Figure B-29. Water circulation, high temperature reheat, and other critical design features would be investigated in this facility.

Figure B-29. Test Facility "B" — Advanced Steam (2400p/1000 F/1200 F) — Atmospheric Fluidized Bed

Facility "C" would be an adaptation of an AFB facility having 3.66 x 3.51 m (12 x 11.5 ft) main bed cells. Each of the three main cells would be used for proof of particular aspects of plant design. As illustrated in Figure B-30, cell "C" would produce saturated steam at 16550 kPa (2400 psi). Cells "A" and "B" would operate at 9308 kPa (1350 psi) and would superheat

Figure B-30. Pilot Plant Facility "C" — Advanced Steam (2400p/1000 F/1200 F) — Atmospheric Fluidized Bed

steam to 922 K (1200 F). The steam would then be desuperheated to 769 K (925 F) for use in the power plant at the Facility "C" site.

The Logic Flow Diagram for this development plan (Figure B-31) shows the sequence of testing at these facilities. Critical component developments are those for the 922 K (1200 F) reheat steam turbine, the AFB fireside developments already underway, and the hot soak tests for 922 K (1200 F) reheat. The pilot plants only comprise AFB units, and would be undertaken concurrently with turbine component development. To assure feasibility for the overall plant concept, a multitower plant simulation would precede the decision to build the demonstration plant.

Table B-41 presents an enumeration of the technology issues to be addressed in the development plan. Those unique to the 16550 kPa (2400 psig), 922 K (1200 F) reheat plant are

Figure B-31. Logic Flow Diagram — Advanced Steam (2400p/1000 F/1200 F) — Atmospheric Fluidized Bed

the last three items under the AFB Module heading and all items for the steam turbine-generator. All of the preceding issues should be addressed under the ongoing AFB development program. The cost for these basic AFB fireside development items are included in Figure B-32, Development Schedule and Costs, as the first component technology development item (64.6 M\$). A detailed breakdown of this item is given in the discussion of Development Schedule and Costs for the supercritical steam-*AFB* plant (see Cycle A, Appendix C).

The total cost for development is 438 M\$, which includes all costs through the first year of checkout and performance testing of a single AFB tower module and steam turbine in a 300 MW (300 MWe) demonstration plant. No credit for generated power is taken in these costs. The demonstration plant costs were projected from the conceptual design plant with an added learning factor of 20% for all items that are not routine steam power plant construction components. The resulting cost estimate was \$727/kW whereas the conceptual design plant estimate was \$542/kW including interest during construction and a 20% contingency.

Costs in Figure B-32 are quoted in 1975 dollars, and the schedule starts in mid-1975.

Table B-41

TECHNOLOGY ISSUES

ADVANCED STEAM CYCLE (2400 p/1000 F/1200 F) — ATMOSPHERIC FLUIDIZED BEDS

AFB Modules
<p>Energy release pattern within main cells</p> <p>Sulfur-lime ratio for 85 percent sulfur capture</p> <p>Tube fireside corrosion and erosion</p> <p>Bed startup for vertical stacked beds</p> <p>Range for turndown of main beds</p> <p>Fuel-limestone injection and distribution</p> <p>Geometric scale effects to estimate full-scale equipment performance from reduced-scale AFB main bed tests</p> <p>Thermal stress concentrations where cold airbox abuts hot bed zones</p> <p>Circulation adequacy for natural and pumped circuits at 2400 psig</p> <p>Durability and availability when producing 600 psi, 1200 F reheat steam</p> <p>Multitower capability to load-follow the steam turbine-generator</p>
Steam Turbine-Generator
<p>Develop cooling means for 1200 F reheat turbine section for buckets, nozzles, shells and rotors</p> <p>Develop materials to reduce cooling requirement for enhanced efficiency</p>

Cost for Development of 2400 psig, 1200 F Reheat AFB and Steam Turbine Generator

Major Milestones for Development Schedule

① Basic AFB Combustion and Fireside Proven	⑤ Steam Turbine 1200 F Reheat Feasibility Assured
② AFB Add-On Pilot Facility "C" Ready for Test	⑥ AFB Pilot Operations Proven for 2400 psig, 1000 F and 600 psi, 1200 F Reheat
③ Multitower and Plant Operational Feasibility Determined on Mathematical Simulation	⑦ Demonstration Plant Designed, Erected, and Ready for Test
④ Control Automation Determined for Demonstration and Commercial Plants	⑧ Demonstration Checkout and Performance Testing Complete; Endurance Tests Continue with Costs Offset by Power Generated

Figure B-32. Development Schedule and Costs — Advanced Steam — AFB, 2400 psig, 1000 F/1200 F

B.4 REFERENCE CYCLES

The evaluation methodologies described in this report involve a detailed comparison of each advanced cycle to a group of four reference cycles which represent the state of the art. In this appendix, cost and performance data are summarized for these reference cycles:

- Open cycle gas turbine burning oil
- Open cycle gas turbine, combined cycle, burning oil
- Steam cycle, conventional furnace burning high sulfur coal with wet stack gas scrubbing to remove sulfur
- Steam cycle, light water reactor

The gas turbine and gas turbine combined cycle (Tables B-42 and B-43, Figures B-33 and B-34) are representative of the conventional technologies which compete for peaking and midrange applications. Cost and performance were estimated for the major components in these plants by consultation with General Electric's Gas Turbine Division and Medium Steam Turbine Department. Cost estimates for the balance-of-plant items were obtained by scaling the estimates generated by Bechtel Corporation in the Energy Conversion Alternatives Study, ECAS (Ref. B-10). This scaling was done to maintain consistency with the costing procedures used in the ECAS work, and it resulted in estimates which are consistent with the higher range of costs experienced by the utilities in 1975.

Data for the conventional steam cycle burning coal (Table B-44, Figure B-35) were obtained from work performed in parallel to the ECAS study (Ref. B-11). The team members involved in this effort were the same as those involved in ECAS (General Electric, Foster Wheeler, and Bechtel), and the level of detail considered in the conceptual design is the same as for the seven ECAS Task II cycles (summarized in Appendix C of this report).

A breakdown of the plant capital cost estimates into major categories is given in Table B-45 for the three fossil fired cycles described above.

A nuclear power plant has also been included as one of the reference cycles in this study. The data for this plant were specified by EPRI and are summarized in Table B-46.

Table B-42

**SUMMARY OF PERFORMANCE AND COST
CONVENTIONAL OPEN CYCLE GAS TURBINE - OIL**

CYCLE PARAMETER	VALUE		
Cross Power Output	77.0 MWe		
Auxiliary Loads	1.0 MWe		
Net Power Output	76.0 MWe (60Hz, 13.8kV)		
Thermodynamic Efficiency	31.4 %		
Power Plant Efficiency	31.0 %		
Overall Efficiency (oil/semiclean liquid)	31.0 %/22.9%		
Fuel	Oil, No. 2, 19663 Btu/lb HHV		
Prime Cycle	Gas Turbine (Air Cooled)		
	Turbine Inlet Temperature 2000 F		
	Compressor Pressure Ratio 11.3		
Heat Rejection	Stack Gas Temperature 974 F		
Fuel Cost			
Fuel Cost in 1975	1.85 \$/MBtu		
Fuel Cost Escalation Rate	1975-1990	8.5 %/yr	
	1991-2000	9.5 %/yr	
	2001-2030	10.5 %/yr	
Operation and Maintenance Cost			
O&M Cost in 1975-Fixed	.53 \$/kWyr		
Variable	1.37 mills/kWh		
O&M Cost Escalation Rate	6.5 %/yr		
Plant Capital Cost			
Plant Construction Time	1 yr		
Total Estimated Plant Cost (1975 dollars)	8.7 M\$		
Plant Cost Estimate in Year of Construction Start	39.4 M\$		
Escalation and Interest During Construction	3.2 M\$		
Capital Cost in Year 2000 when Plant Enters Service	42.6 M\$		
Capital Cost De-escalated to 1975 Dollars	8.8 M\$		
Cost per Installed kW (1975 dollars)	116 \$/kW		
Cost of Electricity			
Levelized Cost of Electricity in Year 2000			
Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	3.4	6.0	15.9
Fuel (Oil)	109.9	109.9	109.9
O&M	2.7	2.9	3.3
Total	116.0	118.8	129.1

Note:
 P - Pressure (psia)
 # - Flow Rate (10 lb/hr)
 F - Temperature
 P/T/#

Figure B-33. Schematic Diagram of Conventional Open Cycle Gas Turbine - Oil

Note:
 P - Pressure (psia)
 # - Flow Rate (10 lb/hr)
 F - Temperature
 P/T/#

Figure B-34. Schematic Diagram of Conventional Open Cycle Gas Turbine Combined - Oil

Table B-43
SUMMARY OF PERFORMANCE AND COST
CONVENTIONAL OPEN CYCLE GAS TURBINE COMBINED - OIL

CYCLE PARAMETER	VALUE		
Gross Power Output	429.6 MWe		
Auxiliary Loads	12.6 MWe		
Net Power Output	417.0 MWe (60Hz, 500kV)		
Thermodynamic Efficiency	43.9 %		
Power Plant Efficiency	42.6 %		
Overall Efficiency (oil/semiclean liquid)	42.6 %/31.5%		
Fuel	Oil, No. 2, 19,663 Btu/lb HHV		
Prime Cycle	Gas Turbine (air cooled) Turbine Inlet Temperature 2000 F Compressor Pressure Ratio 11.3		
Heat Exchangers	Heat Recovery Steam Generator Vapor Generator Pinch Point ΔT 25 F Gas Side $\Delta P/P$.06		
Bottoming Cycle	Steam Turbine Generator Inlet Conditions 900psi/850 F Condenser 2.5 in. HGA, 109 F		
Heat Rejection	Wet Mechanical Draft Cooling Towers (6 cells) Stack Gas Temperature 348 F		
Fuel Cost			
Fuel Cost in 1975	1.85 \$/MBtu		
Fuel Cost Escalation Rate	1975-1990	8.5 %/yr	
	1991-2000	9.5 %/yr	
	2001-2030	10.5 %/yr	
Operation and Maintenance Cost			
O&M Cost in 1975-Fixed	1.44 \$/kW-yr		
Variable	1.29 mills/kWh		
O&M Cost Escalation Rate	6.5 %/yr		
Plant Capital Cost			
Plant Construction Time	3 Years		
Total Estimated Plant Cost (1975 dollars)	112.1 M\$		
Plant Cost Estimate in Year of Construction Start	448.0 M\$		
Escalation and Interest During Construction	119.6 M\$		
Capital Cost in Year 2000 when Plant Enters Service	567.6 M\$		
Capital Cost De-escalated to 1975 Dollars	117.6 M\$		
Cost per Installed kW (1975 dollars)	282 \$/kW		
Cost of Electricity			
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	8.3	14.5	38.6
Fuel (Oil)	80.0	80.0	80.0
O&M	2.9	3.2	4.5
Total	91.2	97.7	123.1

Table B-44
SUMMARY OF PERFORMANCE AND COST
CONVENTIONAL STEAM—WET GAS SCRUBBERS*

CYCLE PARAMETER	VALUE		
Gross Power Output	819.9 MWe		
Auxiliary Loads	72.7 MWe		
Net Power Output	747.2 MWe (60Hz, 500kV)		
Thermodynamic Efficiency	40.7 %		
Power Plant Efficiency	31.8 %		
Overall Efficiency	31.8 %		
Coal Consumption	0.996 lb/kWh		
Total Solid Wastes	0.270 lb/kWh		
Fuel	Coal, Illinois No. 6, 10,788 Btu/lb HHV, 3.9% Sulfur Limestone, Sulfur capture medium used in Stack Gas Scrubbers		
Furnace	Conventional design having radiant and convection sections fired with pulverized coal		
Prime Cycle	Steam Turbine Generator Inlet Condition 3500 psi/1000 F Reheat 1000 F Condenser 2.3 in. HGA, 106 F Wet Mechanical Draft Cooling Towers (20 Cells) Stack Gas Temperature 250 F		
Heat Rejection			
Fuel Cost			
Fuel Cost in 1975	.94 \$/MBtu		
Fuel Cost Escalation Rate	7.2 %/yr		
Operation and Maintenance Cost			
O&M Cost in 1975—Fixed	2.44 \$/kW yr		
Variable	2.18 mills/kWh		
O&M Cost Escalation Rate	6.5 %/yr		
Plant Capital Cost			
Plant Construction Time	5.5 Years		
Total Estimated Plant Cost (1975 dollars)	403.3 M\$		
Plant Cost Estimate in Year of Construction Start	1377.2 M\$		
Escalation and Interest During Construction	754.7 M\$		
Capital Cost in Year 2000 when Plant Enters Service	2131.9 M\$		
Capital Cost De-escalated to 1975 Dollars	442 M\$		
Cost per Installed kW (1975 dollars)	591 \$/kW		
Cost of Electricity			
Levelized Cost of Electricity in Year 2000			
Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	17.3	30.4	81.0
Fuel	24.3	24.3	24.3
O&M	4.9	5.4	7.6
Total	46.5	60.1	112.9

*Source: Ref. B-11

Figure B-35. Conventional Steam Cycle with Wet Gas Scrubbers

Table B-45
PLANT CAPITAL COST ESTIMATES

CATEGORIES	CONVENTIONAL STEAM WET GAS SCRUBBERS	CONVENTIONAL OPEN CYCLE GAS TURBINE COMBINED-OIL	CONVENTIONAL OPEN CYCLE GAS TURBINE OIL
1. Steam Generators	80.04		
2. Turbine Generators	28.78	50.7	6.90
3. Process Mechanical Equipment	63.82	8.9	.71
4. Electrical	36.57	13.9	.33
5. Civil and Structural	38.76	14.3	.08
6. Process Piping and Instrumentation	46.14	7.4	.02
7. Yardwork and Miscellaneous	<u>7.51</u>	<u>3.7</u>	<u>.02</u>
Subtotal	301.62	98.9	8.06
A/E Service and Contingency	101.72	13.2	.68
Total Estimated Plant Cost (1975 Dollars)	403.34	112.1	8.74

Table B-46
SUMMARY OF PERFORMANCE AND COST
CONVENTIONAL STEAM, LIGHT WATER REACTOR*

CYCLE PARAMETERS	VALUE		
Net Power Output	1000 MWe		
Overall Efficiency	32.8%		
Fuel	Uranium		
Prime Cycle	Steam Turbine Generator		
Heat Rejection	Mechanical Draft Cooling Towers		
Fuel Cost			
Fuel Cost in 1975	0.52 \$/MBtu		
Fuel Cost Escalation	7.4 %/yr		
Operation and Maintenance Cost			
O&M Cost in 1975-Fixed	2.67 \$/kWyr		
Variable	0.68 mills/kWh		
O&M Cost Escalation	6.5 %/yr		
Plant Capital Cost			
Plant Design and Licensing Time	4	years	
Construction Time	6	years	
Cost Per Installed kW (1975 Dollars)	776	\$/kW	
Cost of Electricity			
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	22.8	39.9	106.3
Fuel	13.9	13.9	13.9
O&M	<u>2.1</u>	<u>2.7</u>	<u>5.1</u>
Total	38.8	56.5	125.3
*Cost and performance data for this cycle were specified by EPRI for use in this study.			

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- B-12. Energy Conversion Alternatives Study (ECAS), General Electric Phase II Final Report, Vol. III, NASA Report No. NASA-CR-134949, General Electric Company, Schenectady, N.Y., December 1976.

Appendix C

SUMMARY OF POWER CYCLE DATA AND DEVELOPMENT PLANS FROM THE ENERGY CONVERSION ALTERNATIVES STUDY

Performance estimates, cost estimates, and R&D plans were developed for a number of advanced cycles in the recently completed Energy Conversion Alternatives Study (ECAS). The study was conducted under the sponsorship of the Energy Research and Development Administration (ERDA), the National Science Foundation (NSF) and the National Aeronautics and Space Administration (NASA). The work was performed by General Electric, Westinghouse and Burns & Roe/United Technologies and consisted of two phases:

Phase I - Parametric Analysis and Screening of Advanced Cycles

Phase II - Conceptual Design Analysis and Implementation Assessment

Under an agreement between NASA and EPRI, the General Electric ECAS results were made available for use in the study reported here. The Phase I cost and performance numbers (Ref. C-1) are reported in Appendix A along with several new parametric cases performed for EPRI. Appendix C summarizes the conceptual designs, cost estimates, and R&D plans for the seven advanced cycles considered by General Electric in the Phase II ECAS work. (Ref. C-2)

Tables C-1 through C-7 and Figures C-1 through C-7 describe the seven advanced cycles and list costs of electricity for three typical capacity factors. The computational procedure and fuel costs described in Section 3 have been used in computing these electricity costs. Tables C-8 and C-9 summarize the capital cost breakdown and environmental intrusion estimates for each cycle.

R&D plans were outlined for the advanced cycle components in Phase II of ECAS; the schedules and cost estimates are summarized in this appendix. Programs associated with the development of fluidized bed furnaces and the fixed bed gasifier were not included in the ECAS plans. Estimates of furnace development requirements have been generated by Foster Wheeler Development Corporation as part of the present study. The fixed bed gasifier development plan has been estimated by the General Electric team responsible for the GEGAS program. This additional information has been integrated with the original ECAS plans to provide a better estimate of the total development effort required.

Table C-1
SUMMARY OF PERFORMANCE AND COST
CYCLE A
ADVANCED STEAM—ATMOSPHERIC FLUIDIZED BED

Cycle Parameters		Performance/Cost	
Gross Power Output		878.66 MWe	
Auxiliary Loads		64.40 MWe	
Net Power Output		814.26 MWe (60 Hz, 500 kV)	
Thermodynamic Efficiency		43.9 %	
Power Plant Efficiency		35.8 %	
Overall Efficiency		35.8 %	
Coal Consumption		0.884 lb/kWh	
Total Solid Wastes		0.292 lb/kWh	
Fuel		Coal, Illinois No. 6, 10788 Btu/lb HHV, 3.9% Sulfur	
Furnace		Limestone Sulfur Capture Medium Atmospheric Fluidized Bed Combustor, 4 Modules Main Beds (6/Module) 1550 F Carbon Burnup Cell (1/Module) 2000 F	
Prime Cycle		Steam Turbine Generator Inlet 3500 psi/1000 F Reheat 1000 F Condenser 2.3 in. HGA, 106 F	
Heat Rejection		Wet Mechanical Draft Cooling Towers (24 Cells) Stack Gas Temperature 250 F	
R&D Program Cost		228.3 M\$	
R&D Time		6 Years	
Date of First Commercial Service		1988	
Fuel Cost in 1975		.94 \$/MBtu	
Fuel Cost Escalation Rate		7.2 %/yr	
O&M Cost in 1975 - Fixed		2.68 \$/kW-yr	
Variable		1.75 mills/kWh	
O&M Cost Escalation Rate		6.5 %/yr	
Plant Construction Time		5.5 yr	
Total Estimated Plant Cost (1975 Dollars)		332.3 M\$	
Plant Cost Estimate in Year of Construction Start		1134.6 M\$	
Escalation and Interest During Construction		622.1 M\$	
Capital Cost in Year 2000 When Plant Enters Service		1756.7 M\$	
Capital Cost in Year 2000 Expressed in 1975 Dollars		364 M\$	
Cost Per Installed kW (1975 Dollars)		447 \$/kW	
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	13.1	23.0	61.2
Fuel	21.5	21.5	21.5
O&M	4.1	4.7	7.1
Total	38.7	49.2	89.8

Figure C-1. Schematic Diagram of Advanced Steam Cycle--Atmospheric Fluidized Bed (Cycle A)

Table C-2
SUMMARY OF PERFORMANCE AND COST
CYCLE B
ADVANCED STEAM—PRESSURIZED FLUIDIZED BED

Cycle Parameters		Performance/Cost	
Gross Power Output		943.63 MWe	
Auxiliary Loads		39.86 MWe	
Net Power Output		903.77 MWe (60 Hz, 500 kV)	
Thermodynamic Efficiency		41.3 %	
Power Plant Efficiency		39.2 %	
Overall Efficiency		39.2 %	
Coal Consumption		0.808 lb/kWh	
Total Solid Wastes		0.343 lb/kWh	
Fuel		Coal, Illinois No. 6, 10788 Btu/lb HHV, 3.9% Sulfur Dolomite, Sulfur Capture Medium,	
Furnace		Pressurized Fluidized Bed Combustor, 4 Modules Main Bed Cells (6/Module) 1650 F Carbon Burnup Cell (1/Module) 2000 F Pressurizing Gas Turbine (1/Module) Inlet Temperature 1600 F Pressure Ratio 10:1	
Prime Cycle		Steam Turbine Generator Inlet 3500 psi/1000 F Reheat 1000 F Condenser 2.3 in. HGA, 106 F	
Heat Rejection		Wet Mechanical Draft Cooling Towers (22 Cells) Stack Gas Temperature 300 F	
R&D Program Cost		380.2 M\$	
R&D Time		12 Years	
Date of First Commercial Service		1994	
Fuel Cost in 1975		0.94 \$/MBtu	
Fuel Cost Escalation Rate		7.2 %/yr	
O&M Cost in 1975 - Fixed		2.45 \$/kW yr	
Variable		2.10 mills/kWh	
O&M Cost Escalation Rate		6.5 %/yr	
Plant Construction Time		5.5 yr	
Total Estimated Plant Cost (1975 Dollars)		422.0 M\$	
Plant Cost Estimate in Year of Construction Start		1440.9 M\$	
Escalation and Interest During Construction		789.6 M\$	
Capital Cost in Year 2000 When Plant Enters Service		2230.5 M\$	
Capital Cost in Year 2000 Expressed in 1975 Dollars		462 M\$	
Cost Per Installed kW (1975 Dollars)		511 \$/kW	
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	15.0	26.3	70.0
Fuel	19.7	19.7	19.7
O&M	4.7	5.3	7.5
Total	39.4	51.3	97.2

**Figure C-2. Schematic Diagram of Advanced Steam Cycle--Pressurized Fluidized Bed (Cycle B)
(1650 F Main Beds)**

Table C-3
SUMMARY OF PERFORMANCE AND COST
CYCLE C
CLOSED CYCLE GAS TURBINE--HELIUM--ORGANIC BOTTOMING

Cycle Parameters		Performance/Cost	
Gross Power Output		514.79 MWe	
Auxiliary Loads		39.08 MWe	
Net Power Output		475.71 MWe (60 Hz, 500 kV)	
Thermodynamic Efficiency		50.0 %	
Power Plant Efficiency		39.9 %	
Overall Efficiency		39.9 %	
Coal Consumption		0.792 lb/kWh	
Total Solid Wastes		0.262 lb/kWh	
Fuel		Coal, Illinois No. 6, 10788 Btu/lb HHV, 3.9% Sulfur	
		Limestone, Sulfur Capture Medium	
Furnace		Atmospheric Fluidized Bed (2 Stage)	
		Upper Stage	1550 F
		Lower Stage	2000 F
Prime Cycle		Gas Turbine Generator (Helium)	
		Turbine Inlet	1850 F
		Compressor Pressure Ratio 3.2	
		Maximum Discharge Pressure 1000 psi	
Heat Exchangers		Helium/Helium Recuperators	
		Maximum Temperature 1021 F	
		Helium/Organic Boiler	
		Maximum Temperature 588 F	
Bottoming Cycle		Organic Rankine Cycle (Fluorinol 85)	
		Turbine Inlet Condition 700 psi/440 F	
		Condenser 2.3 psia, 112 F	
Heat Rejection		Wet Mechanical Draft Cooling Towers (15 Cells)	
		Stack Gas Temperature 354 F	
R&D Program Cost		964.4 M\$	
R&D Time		15 Years	
Date of First Commercial Service		1997	
Fuel Cost in 1975		0.94 \$/MBtu	
Fuel Cost Escalation Rate		7.2 %/yr	
O&M Cost in 1975 - Fixed		1.42 \$/kW yr	
Variable		1.58 mills/kWh	
O&M Cost Escalation Rate		6.5 %/yr	
Plant Construction Time		5.0 yr	
Total Estimated Plant Cost (1975 Dollars)		394.1 M\$	
Plant Cost Estimate in Year of Construction Start		1388.7 M\$	
Escalation and Interest During Construction		876.6 M\$	
Capital Cost in Year 2000 When Plant Enters Service		2065.3 M\$	
Capital Cost in Year 2000 Expressed in 1975 Dollars		428 M\$	
Cost Per Installed kW (1975 Dollars)		899 \$/kW	
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	26.4	46.2	123.2
Fuel	19.3	19.3	19.3
O&M	3.4	3.7	5.0
Total	49.1	69.2	147.5

Figure C-3. Schematic Diagram of Closed Cycle Gas Turbine--Organic Bottoming (Cycle C)

Table C-4
SUMMARY OF PERFORMANCE AND COST
CYCLE D
POTASSIUM TOPPING CYCLE

Cycle Parameters		Performance/Cost	
Gross Power Output		1032.76 MWe	
Auxiliary Loads		36.97 MWe	
Net Power Output		995.79 MWe (60 Hz, 500 kV)	
Thermodynamic Efficiency		47.8 %	
Power Plant Efficiency		44.4 %	
Overall Efficiency		44.4 %	
Coal Consumption		0.713 lb/kWh	
Total Solid Wastes		0.302 lb/kWh	
Fuel		Coal, Illinois No. 6, 10782 Btu/lb HHV, 3.9% Sulfur Dolomite, Sulfur Capture Medium	
Furnace		Pressurized Fluidized Bed (4 Modules) Main Bed Cells (6/Module) 1750 F Carbon Burnup Cells (1/Module) 2000 F Pressurizing Gas Turbine (1/Module) Inlet Temperature 1700 F Pressure Ratio 10	
Prime Cycle		Metal Vapor Rankine (Potassium) Turbine Inlet 15.2 psi/1400 F Condenser 2.4 psi/1100 F	
Heat Exchanger		Metal Vapor Condenser/Steam Generator Potassium (Shell Side) 2.4 psia, 1100 F Steam (Tube Side) 746 - 4394 psi, 1000 F	
Bottoming Cycle		Steam Turbine Generator Inlet 3500 psi/1000 F Reheat 1000 F Condenser 2.3 in. HGA, 106 F	
Heat Rejection		Wet Mechanical Draft Cooling Towers (19 Cells) Stack Gas Temperature 300° F	
R&D Program Cost		844.8 M\$	
R&D Time		18 Years	
Date of First Commercial Service		2001	
Fuel Cost in 1975		0.94 \$/MBtu	
Fuel Cost Escalation Rate		7.2 %/yr	
O&M Cost in 1975 - Fixed		1.94 \$/kWyr	
Variable		2.30 mills/kWh	
O&M Cost Escalation Rate		6.5 %/yr	
Plant Construction Time		5.5 yr	
Total Estimated Plant Cost (1975 Dollars)		600.0 M\$	
Plant Cost Estimate in Year of Construction Start		2048.7 M\$	
Escalation and Interest During Construction		1122.7 M\$	
Capital Cost in Year 2000 When Plant Enters Service		3171.4 M\$	
Capital Cost in Year 2000 Expressed in 1975 Dollars		657 M\$	
Cost Per Installed kW (1975 Dollars)		661 \$/kW	
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	19.4	34.0	90.5
Fuel	17.4	17.4	17.4
O&M	4.9	5.4	7.1
Total	41.7	56.8	115.0

Figure C-4. Schematic Diagram of Potassium Topping Cycle (Cycle D)

Table C-5
SUMMARY OF PERFORMANCE AND COST
CYCLE E
OPEN CYCLE GAS TURBINE COMBINED-WATER COOLED-
SEMICLEAN LIQUID FUEL

Cycle Parameters		Performance/Cost	
Gross Power Output		873.0 MWe	
Auxiliary Loads		26.5 MWe	
Net Power Output		846.5 MWe (60 Hz, 500 kV)	
Thermodynamic Efficiency		52.7 %	
Power Plant Efficiency		51.1 %	
Overall Efficiency		37.8 %	
Coal Consumption		0.838 lb/kWh	
Total Solid Wastes		0 lb/kWh	
Fuel		Semiclean Liquid Derived From Coal, 16700 Btu /lb HHV, 0.48% Sulfur, 1.30% Nitrogen, 0.20% Ash Fuel Treatment: Waterwash, Magnesium Oxide	
Prime Cycle		Gas Turbine (Water Cooled) Turbine Inlet Temperature 3000 F Compressor Pressure Ratio 16	
Heat Exchangers		Heat Recovery Steam Generator Vapor Generator Pinch Point ΔT 77 F Gas Side $\Delta P/P$ 0.05	
Bottoming Cycle		Steam Turbine Generator Inlet Conditions 2400 psi/1000 F Reheat 1000 F Condenser 2.3 in. HGA, 106 F	
Heat Rejection		Wet Mechanical Draft Cooling Towers (11 Cells) Stack Gas Temperature 305 F	
R&D Program Cost		291.9 M\$	
R&D Time		14 Years	
Date of First Commercial Service		1996	
Fuel Cost in 1975		3.50 \$/MBtu	
Fuel Cost Escalation Rate		7.2 %/yr	
O&M Cost in 1975 - Fixed		1.08 \$/kW-yr	
Variable		1.16 mills/kWh	
O&M Cost Escalation Rate		6.5 %/yr	
Plant Construction Time		5.0 yr	
Total Estimated Plant Cost (1975 Dollars)		237.9 M\$	
Plant Cost Estimate in Year of Construction Start		838.1 M\$	
Escalation and Interest During Construction		408.0 M\$	
Capital Cost in Year 2000 When Plant Enters Service		1246.1 M\$	
Capital Cost in Year 2000 Expressed in 1975 Dollars		258 M\$	
Cost Per Installed kW (1975 Dollars)		305 \$/kW	
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	9.0	15.7	41.8
Fuel	56.2	56.2	56.2
O&M	2.5	2.8	3.7
Total	67.7	74.7	101.7

Note

Pressure (psia) / Temperature (°F) / Flow Rate (x 10⁶ Lb/hr) / Enthalpy (Btu/lb)
Flow Rate (x 10⁶ Lb/hr)

Figure C-5. Schematic Diagram of Open Cycle Gas Turbine Combined--Water Cooled (Cycle E)

Table C-6
SUMMARY OF PERFORMANCE AND COST
CYCLE F
OPEN CYCLE GAS TURBINE COMBINED—AIR COOLED—
LOW Btu GASIFIER

Cycle Parameters		Performance/Cost		
Gross Power Output		607.2 MWe		
Auxiliary Loads		22.4 MWe		
New Power Output		584.8 MWe (60 Hz, 500 kV)		
Thermodynamic Efficiency		--		
Power Plant Efficiency		39.6 %		
Overall Efficiency		39.6 %		
Coal Consumption		0.799 lb/kWh		
Total Solid Wastes		0.103 lb/kWh		
Fuel		Coal, Illinois No. 6, 10788 Btu/lb HHV, 3.9% Sulfur		
Gasifier		Fixed Bed Type (263 psia) Low Btu Gas 3063/2806 Btu/lb (HHV/LHV) .14% Sulfur, 0.04% NH ₃		
Gas Cleanup		Alkazid Process + Claus for H ₂ S Removal		
Prime Cycle		Gas Turbine Generator (Air Cooled) Turbine Inlet Temperature 2400 F Compressor Pressure Ratio 12		
Heat Exchangers		Heat Recovery Steam Generator Vapor Generator Pinch Point ΔT 19 F Gas Side Δ P/P 0.05		
Bottoming Cycle		Steam Turbine Generator Inlet Conditions 1800 psi/950 F Reheat 950 F Condenser 2.3 in. HGA, 106 F		
Heat Rejection		Wet Mechanical Draft Cooling Towers (8 Cells) Stack Gas Temperature 312 F		
R&D Program Cost		228.4 M\$		
R&D Time		11 Years		
Date of First Commercial Service		1993		
Fuel Cost in 1975		0.94 \$/MBtu		
Fuel Cost Escalation Rate		7.2 %/yr		
O&M Cost in 1975 - Fixed		1.25 \$/kWyr		
Variable		1.93 mills/kWh		
O&M Cost Escalation Rate		6.5 %/yr		
Plant Construction Time		5.0 yr		
Total Estimated Plant Cost (1975 Dollars)		303.0 M\$		
Plant Cost Estimate in Year of Construction Start		1067.7 M\$		
Escalation and Interest During Construction		520.1 M\$		
Capital Cost in Year 2000 When Plant Enters Service		1587.8 M\$		
Capital Cost in Year 2000 Expressed in 1975 Dollars		329 M\$		
Cost Per Installed kW (1975 Dollars)		562 \$/kW		
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)				
Capacity Factor	0.70	0.40	0.15	
Capital	16.5	28.9	77.0	
Fuel	19.5	19.5	19.5	
O&M	4.0	4.3	5.4	
Total	40.0	52.7	101.9	

Figure C-6. Schematic Diagram of Open Cycle Gas Turbine Combined--Air Cooled--LBtu Gasifier (Solid Fuel Emission Specifications) (Cycle F)

Table C-7
SUMMARY OF PERFORMANCE AND COST
CYCLE G
OPEN CYCLE MHD

Cycle Parameters		Performance/Cost	
Gross Power Output		1993.0 MWe (60 Hz ac)	
Auxiliary Loads		61.0 MWe	
Net Power Output		1932.0 MWe (60 Hz, 500 kV)	
Thermodynamic Efficiency		54.0 %	
Power Plant Efficiency		49.8 %	
Overall Efficiency		48.3 %	
Coal Consumption		0.655 lb/kWh	
Total Solid Wastes		0.082 lb/kWh	
Fuel		Coal, Illinois No. 6, 10788 Btu/lb HHV, 3.9% Sulfur IBtu Gas-Reducing Agent for Seed Regeneration	
Furnace		High Performance Combustor Pressure 9 Atm Inlet Air Temperature 2500 F Exhaust Temperature 4634 F	
Prime Cycle		Diagonal MHD Generator Average Magnetic Flux 5 Tesla Diffuser Outlet Pressure 1.14 Atm Electrical Load Parameter 0.80 Potassium Seeding 1%	
Heat Exchangers		High Temperature Air Heater, Refractory Ceramic Storage Type 2225-2960 F Radiant Furnace 2960-3662 F Secondary Furnace 765-2225 F Economizers 250-765 F	
Bottoming Cycle		Steam Turbine Generator Inlet Condition 3500 psi/1000 F Reheat 1000 F Condenser 2.3 in. HGA, 106 F	
Heat Rejection		Wet Mechanical Draft Cooling Towers (25 Cells) Stack Gas Temperature 251 F	
R&D Program Cost		1444 M\$	
R&D Time		19 Years	
Date of First Commercial Service		2003	
Fuel Cost in 1975*		0.97 \$/MBtu	
Fuel Cost Escalation Rate		7.2 %/yr	
O&M Cost in 1975 - Fixed		1.37 \$/kWyr	
Variable		1.50 mills/kWh	
O&M Cost Escalation Rate		6.5 %/yr	
Plant Construction Time		6.5 years	
Total Estimated Plant Cost (1975 Dollars)		826.5 M\$	
Plant Cost Estimate in Year of Construction Start		2649.8 M\$	
Escalation and Interest During Construction		1799.2 M\$	
Capital Cost in Year 2000 When Plant Enters Service		4449.0 M\$	
Capital Cost in Year 2000 Expressed in 1975 Dollars		922 M\$	
Cost Per Installed kW (1975 Dollars)		477 \$/kW	
Levelized Cost of Electricity in Year 2000 Expressed in 1975 Dollars (mills/kWh)			
Capacity Factor	0.70	0.40	0.15
Capital	14.0	24.5	65.3
Fuel	16.5	16.5	16.5
O&M	3.2	3.6	4.8
Total	33.7	44.6	86.6

*coal price at .94\$/MBtu plus allowance for cost of
IBtu gas used in seed regeneration.

Figure C-7. Schematic Diagram of Open Cycle MHD (Cycle G)

Table C-8
PLANT CAPITAL COST ESTIMATES

Cycle Identification:	A	B	C	D	E	F	G
	Cost* in M\$ (1975 Dollars)						
<u>Categories</u>							
1. Steam Generators	71.16	90.55	113.20	157.63	20.39	14.92	135.59
2. Turbine Generators	30.00	54.05	38.11	87.90	65.86	44.42	87.13
3. Process Mechanical Equipment	50.55	72.89	75.40	71.24	20.05	19.54	137.94
4. Electrical	35.74	29.09	25.41	36.31	28.65	31.11	93.18
5. Civil and Structural	33.46	30.18	27.04	43.98	21.30	23.79	75.96
6. Process Piping and Instrumentation	25.84	45.77	23.64	67.82	22.90	17.92	89.07
7. Yardwork and Miscellaneous	4.72	4.72	4.38	4.60	4.39	5.02	13.40
8. Gasification Cleanup System	--	--	--	--	--	43.09	--
9. Gasifier	--	--	--	--	--	29.89	--
Subtotal	251.47	327.25	307.18	469.05	183.54	229.70	632.27
A/E Service and Contingency	80.80	94.74	86.94	130.94	54.32	73.31	194.19
Total Estimated Plant Cost (1975 Dollars)	332.27	421.99	394.12	599.99	237.86	303.01	826.46

*Includes major component costs, direct and indirect labor costs.

Table C-9
ENVIRONMENTAL INTRUSION

Cycle Identification :	A	B	C	D	E	F	G
	Emissions in lb/MBtu (input)						
Gaseous Emissions							
SO _x (as SO ₂)	1.028	0.688	1.077	0.688	0.574	1.200	0.500
NO _x (as NO ₂)	0.270	0.152	0.363	0.162	1.7-2.0	0.372	0.300
Hydrocarbons	Trace	Trace	Trace	Trace	< .022	< .018	--
CO	0.040	0.020	0.025	0.020	< .022	< .018	--
Particulates	0.099	0.100	0.100	0.100	0.060	0	0.100
Thermal Pollution							
Heat Rejected in Cooling Towers	4729	3967	3690	3016	1770	2492	2377
Heat Rejected in Stack	909	951	1000	767	1068	1958	606
Solids & Liquids							
Water Discharge	1.320	1.190	0.986	0.905	0.693	0.642	0.750
Ash and Spent Sorbent	0.292	0.342	0.262	0.302	--	0.077	0.058
Sulfur	--	--	--	--	--	0.026	0.021

Each development plan is keyed to the cycle configuration presented in Tables C-1 through C-9 and Figures C-1 through C-7. The plans generally include: (1) component development, (2) pilot plant construction and testing, and (3) demonstration plant design, construction and testing.

The component development phase is intended to provide solutions for the principal technology problems which must be overcome to establish the feasibility of the advanced components in the power plant concept.

The technical purpose of the pilot plant phase is to test the advanced components in a system configuration which will reveal any major component problems that might occur in the final integration of the power plant. The programmatic significance of the pilot plant is to provide performance data to minimize the risk in the decision to proceed with the demonstration phase, which is the largest cost element in the overall development plan.

The demonstration plant must demonstrate all of the component and system performance characteristics on a plant size scale which will permit a low risk technical decision by a supplier to offer the power plant for commercial sale. The demonstration plant operation must also exhibit a reliability and availability potential sufficient to engender confidence by the utilities to purchase a commercial plant.

It is assumed that after appropriate testing of the demonstration plant the energy conversion system could be considered for selection as a commercial offering. As presented, the plans do not include costs for extended operation of the demonstration plant or for the design and construction of the first commercial unit.

The R&D schedules presented here begin in 1975 and the costs are quoted in 1975 dollars. The date of first commercial service is computed as follows:

$$\begin{array}{ccccccc} \text{Year 1975} & + & \text{Development} & + & \text{Two Year} & + & \text{Commercial} & = & \text{Date of First} \\ & & \text{Time} & & \text{Decision} & & \text{Plant} & & \text{Commercial} \\ & & & & \text{Period} & & \text{Construction} & & \text{Service} \\ & & & & & & \text{Time} & & \end{array}$$

Figure C-8 describes the AFB-steam plant program. The costs have been divided into two categories: one includes all the elements associated with the AFB furnace development while the other summarizes the cost of integrating the furnace and the steam cycle. Furnace testing facilities "A" and "B" are fictitious but have been modeled after the existing facility in Alexandria, Virginia* and the proposed facility at Morgantown, West Virginia.**

*Pope Evans and Robbins, Inc. under OCR/ERDA sponsorship

**U.S. Bureau of Mines, Morgantown Engineering Research Center

Phase	Year						Cost of Basic Fluid Bed Technology Development	Cost of Integrated Steam Plant Development
	1	2	3	4	5	6	M\$	M\$
I. Program Definition Study	Continuing →							
II. Component Design and Technology Development								
1. Engineering Test Facilities to Study Combustion, Heat Transfer, Coal Fines Recycle, Carbon Burnup, Cell Operation, Corrosion and Materials								
Facility "A" (0.7 MW)							3.0	
Facility "B" (6 MW)							24.2	
2. Modeling and Simulation of Single Cells and Multi-cell Interaction with Steam Cycle								6.0
III. Pilot Plant (30 MW)								
Three Beds and a Carbon Burnup Cell in Horizontal Array Generating Steam at 1350 psi/925 F (Facility "C")								
1. Construction							26.0	
2. Testing							11.4	
IV. Demonstration Plant (220 MW)								
Six Beds and a Carbon Burnup Cell in a Vertical Tower Driving a Steam Turbine (3500 psi/1000 F/1000 F)								
1. Design and Construction								128.7*
2. Checkout Testing								29.0
	Total Costs						64.6	163.7
	Total Development Cost:							228.3 M\$

*Ref. C-2, Volume III, p. A-7.

Figure C-8. Schedule and Costs for Development Plan-Advanced Steam-Atmospheric Fluidized Bed (Cycle A)

The pilot plant (Facility "C") has been modeled after the Rivesville, West Virginia facility built by Pope Evans and Robbins and Foster Wheeler Development Corporation under OCR/ERDA sponsorship. The demonstration plant cost was estimated in ECAS Phase II; it includes interest during construction and a 20% learning factor on the costs for the advanced components.

Figure C-9 describes a plan for the PFB-steam cycle. The program definition study is equivalent to General Electric's Coal Fired Combined Cycle (CFCC) study. Several facilities have been identified for the component testing phase. Facility "A" is modeled after the Combustion Power Company facility in California, "B" is like a proposed Argonne National Laboratory facility, and "C" is like the facility proposed by Curtiss Wright Company for heating air in a tubed bed. The international program item is an estimate of U.S. contributions to the facility in Grimethorpe, U.K., which is sponsored by ERDA and the International Energy Association. The pilot plant includes only the furnace and gas turbine costs with a 100% learning factor. The demonstration plant cost was estimated previously in the ECAS program.

In order to compare R&D costs fairly, it is necessary that each advanced cycle be treated as though there were no other parallel development going on. For instance, the AFB furnace for the closed helium gas turbine cycle (Figure C-10, Cycle C) can be thought of as a continuation of the AFB development undertaken for steam cycle applications. However, it would not be consistent to charge all of the basic fireside development costs to the AFB-steam and then charge only the incremental costs to the AFB-helium. Therefore, the costs tabulated in Figure C-10 include the cost of 64.6 M\$ required for basic fireside development as well as the unique costs associated with the AFB-helium furnace. This approach treats each cycle as though it were an independent alternative and answers the question: "What would it cost to develop either the AFB-steam cycle or the AFB-helium cycle starting from scratch in 1975?"

Figure C-11 shows the development plan for the potassium topping cycle and PFB furnace. The plan for the cycle components is derived from the ECAS work. The PFB/potassium costs were estimated by starting with the basic PFB-steam development cost and adding the additional costs for work unique to the boiling potassium furnace.

Figure C-12 gives a summary of the schedule and costs for Cycle E; this is taken directly from the ECAS reports without modification.

Phase	Year												Cost of Basic PFB Technology Development	Cost of Integrated Steam Plant Development
	1	2	3	4	5	6	7	8	9	10	11	12	M\$	M\$
I. Program Definition Study													3.0	1.5
II. Component Design and Technology Development														
1. Materials Selection for Pressurizing Gas Turbine													3.0	
2. Engineering Test Facilities														
Combustion Dynamics, Heat Transfer, Fines Recycle, Carbon Burnup Cell Operation, Gas Cleanup, Sorbent Regeneration, Corrosion and Materials for Beds and Gas Turbines														
Facility "A" (20 MW)													20.0	
Facility "B" (4.7 MW)													18.0	
Facility "C" (59 MW)													47.5	
U.S. Participation in International PFB Program													7.5	
3. Modeling and Simulation of Single Cells and Multi- cell Interactions with Steam Cycle														7.0
III. Pilot Plant (117 MW)														
Three Beds and a Carbon Burnup Cell in Vertical Tower with Integrated Pressurizing Gas Turbine and Steam Cycle.														
1. Design and Construction													50.0*	
2. Testing													35.0	
IV. Demonstration Plant (225 MWe)														
Six Beds and a Carbon Burnup Cell in a Vertical Tower Driving a Steam Turbine (3500 psi/1000 F/1000 F)														
1. Design and Construction														159.7**
2. Checkout Testing														28.0
Total Cost													184.0	196.2
Total Development Cost														380.2 M\$

*Cost of PFB, gas filters, and gas turbine only; pilot plant is assumed to be built on an existing steam plant site with coal and waste handling facilities already in place

**Ref. C-2, Vol. III, p. A-9.

Figure C-9. Schedule and Costs for Development Plan-
Advanced Steam-Pressurized Fluidized Bed
(Cycle B)

Phase	Year															Cost of Second Stage Fluid Bed Technology Development	Cost of Integrated Plant Development
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	M\$	M\$
Development of Closed Helium Cycle Exclusive of AFB and Ceramic Tubes (from ECAS)																	
I. Program Definition Study																	3.7
II. Component Design and Technology Development																	14.2
III. Technology Readiness Proof Tests and Pilot Plant																	182.3
IV. Demonstration Plant																	647.3
<u>AFB Development Plan:</u>																	
Costs of Basic Fluid Bed Technology Development (see AFB/Steam Development Plan)																64.6	
II. Component Design and Technology Development																	
1. Materials Screening Test at Facility "A"																0.5	
2. Two Stage Bed Installation and Testing at Facility "B"																9.0	
III. Pilot Plant (50 MW)																	
Additional Tasks Not Included in III Above Which Are Associated With Testing the Unique Features of the Two Stage AFB																13.2	
IV. Demonstration Plant (470 MW)																	
Additional Tasks Not Included in IV Above for Testing AFB																29.6	
	Total Costs															116.9	847.5*
	Total Development Cost**																964.4 M\$

*Ref. C-2, Vol. III, p. 1.3-26

**Excluding Ceramic Tubes Development

Figure C-10. Schedule and Costs for Development Plan-Closed Cycle
Gas Turbine-Helium-Organic Bottoming (Cycle C)

Phase	Year																		Cost of Potassium PFB Development	Cost of Integrated Plant Development
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	M\$	M\$
<u>Development of Potassium Topping Cycle</u>																				
<u>Exclusive of PFB (from ECAS)</u>																				
I. Program Scoping Study																				1.3
II. Component Tests and Materials Development																				75.8
III. Pilot Plant																				230.2
IV. Demonstration Plant																				286.5
<u>PFB Development Plan</u>																				
I. Costs of Basic PFB Technology Development (See PFB/Steam Development Plan)																			184.0	
II. Component Tests and Materials Development																				
1. PFB/Potassium Installation and Testing at PFB/Steam Facility "B"																			8.0	
2. PFB/Potassium Furnace Modeling and Control Study																			18.0	
III. Pilot Plant (125 MW)																				
1. PFB Testing not Included in III Above																			32.0	
IV. Demonstration Plant (250 MW)																				
1. PFB Testing Not Included in IV Above																			9.0	
Total Costs																			251.0	593.8*
Total Development Cost																				844.8 M\$

*Ref. C-2, Vol. III, p. 1.4-27

Figure C-11. Schedule and Costs For Development Plan-Potassium Topping Cycle (Cycle D)

Phase	Year														Cost M\$
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	
<u>Development Plan (From ECAS)</u>															
I. Program Definition Study															4.0
II. Component Design and Technology Development															31.7
III. Technology Readiness Proof Test															59.5
IV. Turbine Prototype Design and Pilot Plant															54.4
V. Demonstration Plant															142.3
	Total Cost														291.9*

*Ref. C-2, Vol. III, p. 1.5-27

Figure C-12. Schedule and Costs For Development Plan-Open Cycle
Gas Turbine Combined-Water Cooled-Semiclean
Liquid Fuel (Cycle E)

Figure C-13 shows a plan for the gas turbine combined cycle with gasifier (Cycle F). Gasifier development has been listed separately from cycle development. The cycle development costs are identical to those reported in ECAS except that the low-Btu combustor development (Phase II, 6 M\$) has been taken out and charged to gasifier development.

Figure C-14 summarizes the open cycle MHD development program as presented in the ECAS report.

Phase	Year											Cost of Gas Turbine and Cycle Development	Cost of Gasifier Subsystem Development
	1	2	3	4	5	6	7	8	9	10	11	M\$	M\$
Development of Advanced Air Cooled Gas Turbine Exclusive of Gasifier (From ECAS)													
I. Program Definition Study												1.1	
II. Component Design and Technology Development												14.0	6.0
III. Turbine Prototype Design and Pilot Plant												25.0	
IV. Demonstration Plant												136.7	
Gasifier Development Plan													
II. Component Tests													
Design and Test Pilot Scale Gasifier with Simulated Tar Recycle and Air Supply													
Install Cleanup System and Tar Recycle Equipment at Pilot Gasifier Site													4.0
Demonstrate Gasifier System Performance Including Heavy Tar Recycle and Gas Cleanup													
Perform Reference Design and Optimization of Gasifier Subsystem													3.0
III. Pilot Plant													
Scaleup of Gasifier and Fabrication													15.0
Install Gasifier at National Test Center													10.0
Test Gasifier as Integrated System with State of the Art Gas Turbine													
IV. Modify Gasifier Design and Manufacture Units for Demonstration Plant													13.6
Total Costs												176.8*	51.6
Total Development Cost													228.4 M\$

*Ref. C-2, Vol. III, p. 1.6-21

Figure C-13. Schedule and Costs For Development Plan-Open Cycle
Gas Turbine-Air Cooled-Low-Btu Gasifier (Cycle F)

Phase	Year																			Cost
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	M\$
I. Component/Subsystem Development																				293
II. Pilot Plant																				708
III. Demonstration Plant																				443
	Total Cost																			1444*

*Ref. C-2, Vol. III, pp. 1.7-25,26

Figure C-14. Schedule and Costs For Development Plan-Open Cycle MHD
(Cycle G)

REFERENCES

- C-1. Energy Conversion Alternatives Study, General Electric Phase I Report, NASA Report No. NASA-CR-134948, General Electric Company, Schenectady, N.Y., February 1976.
- C-2. Energy Conversion Alternatives Study, General Electric Phase II Report, NASA Report No. NASA-CR-134949, General Electric Company, Schenectady, N.Y., December 1976.