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WESTINGHOUSE PHASE I FINAL REPORT

Volume VII — METAL VAPOR RANKINE TOPPING-STEAM & BOTTOMING CYCLES

by

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WESTINGHOUSE ELECTRIC CORPORATION RESEARCH LABORATORIES

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16. Abstract

Adding a metal vapor Rankine topper to a steam cycle is a way to increase the mean temperature at which heat is added to the cycle to raise the efficiency of a power plant. Potassium and cesium topping fluids are considered. Pressurized fluidized bed or pressurized (with an integrated low-Btu gasifier) boilers are assumed. One of the ternary systems studied shows plant efficiency of 42.3% with a plant capitalization of $66.7/kW and a cost of electricity of 8.19 mills/MJ (29.5 mills/kWh).

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Others contributing to the concept study were:

- W. F. Guerin, who defined and costed the liquid metal subsystems.
- J. D. Mangus, who provided technical consultation.
- R. K. Sayre, who designed and costed the liquid metal condenser-steam generator.
- F. A. Beldecos of Power Generation Systems, who sized the needed metal vapor turbines.
- J. L. Steinberg and G. J. Silvestri of the Westinghouse Steam Turbine Division who calculated the performance and price of certain steam turbines.
- C. T. McCreedy and S. M. Scherer of Chas. T. Main, Inc. of Boston, who prepared the balance of plant description and costing, site drawings, and provided consultation on plant island arrangements and plant constructability.

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SUMMARY

Adding a metal vapor Rankine topping cycle to a steam cycle is a way to increase the mean temperature at which heat is added to the cycle and to raise the efficiency of the power plant. The majority of this study uses potassium as the working fluid with a few cesium points for comparison. The systems studied use either a pressurized fluidized bed boiler burning coal directly or a pressurized boiler burning clean fuel gas from an integrated low-Btu gasifier. Included in the cycles are a pressurizing gas turbine with its associated recuperator, and a gas economizer and feedwater heater. The base case system assumes a 1255°K (1800°F) pressurizing turbine inlet temperature and a 15 to 1 pressure ratio. The liquid-metal vapor generator is a fluidized bed boiler. The liquid-metal system uses a boiler with a 2.5 to 1 recirculation ratio, and several four-stage - 30 rps (1800 rpm) double flow-25 MW turbine-generators which exhaust into a metal vapor condenser-steam boiler where steam is raised for a nearly conventional steam-bottoming plant.

The metal vapor enters the turbine at 1033°K (1400°F) and the condenser-steam generator at 866°K (1100°F). The steam-bottoming plant uses a 24.132 MPa (3500 psi) either single or nonreheat plant. The high pressure feedwater heating is accomplished partly by extraction steam and partially by exhaust gas feed heating. A temperature difference of 166.7°K (300°F) is assumed across the metal vapor turbine. The steam reheat and/or superheat temperature is 55.5°K (100°F) less than the metal vapor condensing temperature. These variables are not varied independently.

Calculations show the potassium-topped plant with a capitalization of $667/kW and a plant efficiency of 42.3%.

Results show the comparable cesium cycle to have an efficiency about 0.5 point higher than the potassium cycle but to have a 0.44 mill/MJ (1.6 mills/kWh) higher cost of electricity. The need for both the gasifier and pressurized furnace compared to just a pressurized fluidized bed boiler results in a 17% high plant capitalization. The pressurized fluidized bed system is the choice for the case for further study. Also indicated are a 10 to 1 - 1255°K (1800°F) pressurizing gas turbine, a 1033°K (1400°F) metal turbine inlet temperature, and a 24.132 MPa/811°K/811°K (3500 psi/1000°F/1000°F) steam-bottoming plant.

The 1200 MW plant, made up of several distinct pressurized boiler and liquid-metal turbine loops with the exception of the steam turbine which is common to all loops, can be expected to have a higher availability than a normal plant with line dependence on all major components.

The pressurized fluidized bed boiler plant shows a cost of electricity of 8.19 mills/MJ (29.5 mills/kWh). Extrapolation to other conditions than those calculated shows possible efficiencies of 44% with a possible capital cost of $583/kW and a COE of 6.94 mills/MJ (25 mills/kWh). Some limited potential for this plant may exist.

8. METAL VAPOR RANKINE TOPPING-STEAM BOTTOMING CYCLES

Figure 8.1 is a simplified schematic of an energy conversion system utilizing a Rankine metal vapor topping-steam bottoming cycle. The area enclosed by the heavy broken line is the liquid-metal system discussed in this section. The areas outside the heavy broken line include the furnace-boiler, the pressurizing gas turbine generator, and the steam turbine generator, described in greater detail in Sections 4, 5, 6, and 12. Design support for material selection and the fabrication methods suggested are presented in Section 3.

8.1 State of the Art

Considering the generation of power at present-day temperatures and higher, it must be recognized that steam as a working fluid presents serious problems. It requires too high an operating pressure, and it absorbs too little heat at the maximum cycle temperature. Combining a Rankine steam cycle with a Rankine metal vapor topping cycle overcomes these problems and offers the potential for higher cycle efficiencies.

Historically, between 1922 and 1949, six commercial power generating stations were installed and successfully operated with mercury vapor topping turbines at throttle conditions of about 0.8619 MPa (125 psi) gauge/788°K (958°F). In 1949, the Schiller Station of Public Service of New Hampshire went into operation with a total capacity of 40 MWe, of which 15 MWe were generated by the mercury vapor turbine generator. The 10 MWe mercury turbine generator installed at the Hartford Electric Light Company's South Meadow station in 1928 operated until 1947. It was replaced by a 15 MWe unit in 1949. In general, the metal vapor turbine presented few problems, but some boiler corrosion and necessary replacement did occur. These plants exhibited an efficiency

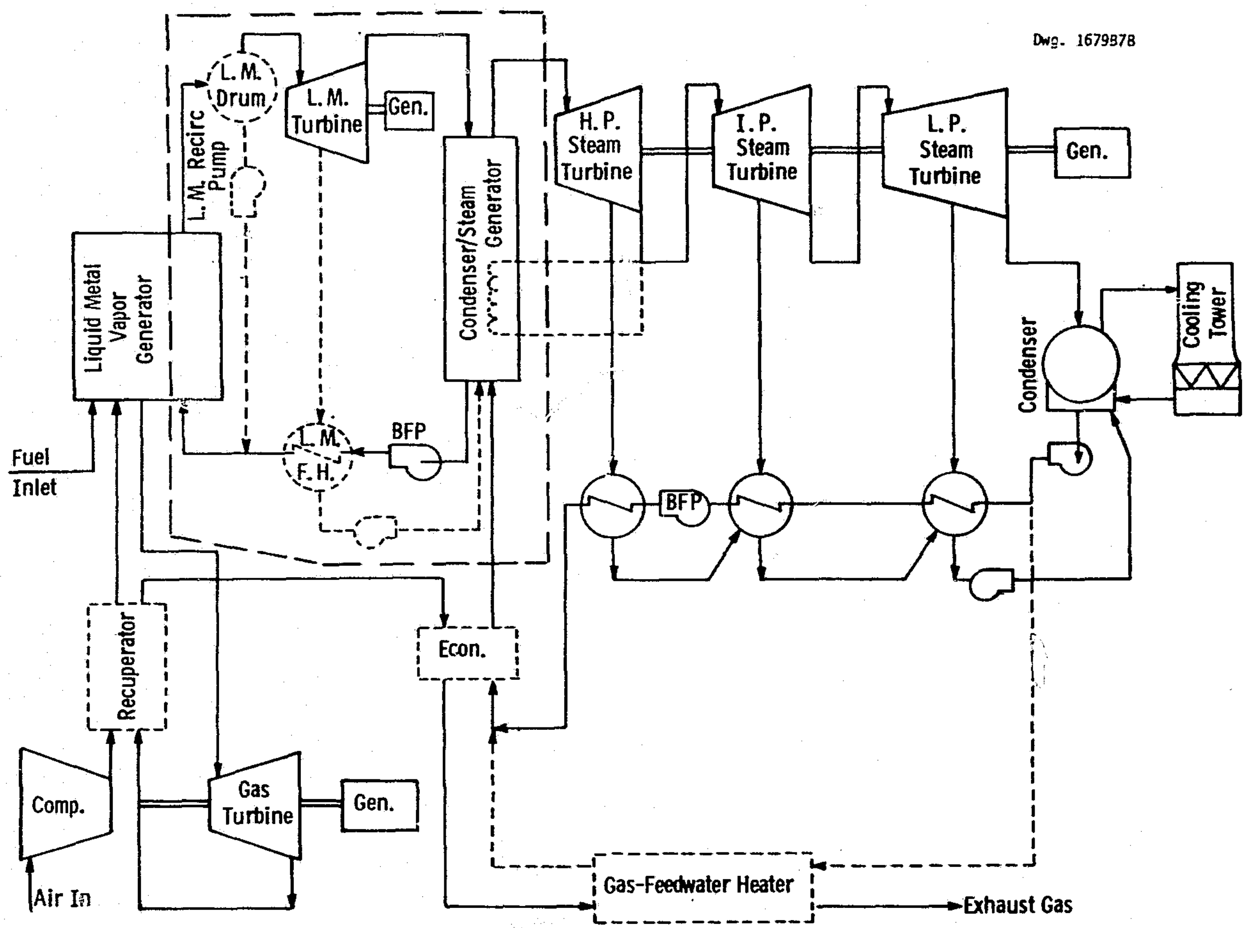

Fig. 8.1—Schematic liquid metal Rankine topping cycle

15% higher than did steam plants with similar top temperatures. Three of these mercury plants were still operating in 1961, but the development of more efficient steam plants (modern plants with higher inlet steam temperatures) and the value of the mercury inventory have since caused them to be dismantled.

More recently, small power plants for space stations using metal vapor turbines (potassium) have been studied. There are now ongoing programs utilizing liquid-metal subsystems for liquid-metal fast breeder reactor (LMFBR) power plants. The pertinent components for which a body of technology has been developed for use in liquid-metal systems are metal vapor condenser-steam generators, feed heaters, pumps, piping systems, valving, expansion joints, purification systems, trace heating systems, inventory control, and metal vapor turbines.

The condenser-steam generator parameters listed in Table 8.1 are indicative of the state of the art as developed by the Energy Research and Development Administration (ERDA) for the LMFBR program.

Table 8.1 - LMFBR Steam Generator Operating Conditions

	Evaporator	Superheater
Temperatures, °F		
Sodium in	855	950
Sodium out	700	855
Water in	470	715
Water out	715	905
Sodium Velocity, ft/s	8.5	11.0
Steam Exit Velocity, ft/s	37.4	173
Pressure Drop, psi		
Water	44	245
Sodium	21	29

Table 8.2 - Characteristics of Sodium Pumps[a]

System	Hallam	EBR-2	Enrico Fermi	500 MWe FBR	P.F.R.	ANL 1000 MWe	FFTF 400 MWt
Primary System Pumps							
Design	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal
Type	Free surface	Free surface	Free surface	Free surface	Free surface	Free surface	Free surface
Number of units	2	2	3	3	3	3	4
Capacity, gpm	7200	5500	38,500	38,500	21,100	62,500	11,750
Dynamic head, ft	160	200	310	379	333	375	385
Design temp., °F	1000	800	1000	1100	752	1175	800
Motor speed, rpm	900	1075	900	600	960	520	870
Motor power, hp	350	350	1060	4000	200	6000	1300
Sealing arrangement	Mechanical shaft seal	Hermetically sealed drive motor	Mechanical shaft seal	Mechanical shaft seal	Mechanical shaft seal	Mechanical shaft seal	Mechanical shaft seal
Material	304 SS	304 SS	304 SS	304 SS			
Type of speed control	Eddy current coupling	Variable freq. and voltage	Wound rotor motor w/liquid rheostat	Eddy current coupling	Hydraulic coupling	WR/DC	Eddy current coupling
Secondary System Pumps							
Design	Centrifugal	ac linear	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal
Type	Free surface	Induction	Free surface	Free surface	Free surface	Free surface	Free surface
Number of units	3	1	3	3	3	3	4
Capacity, gpm	7200	6500	13,000	45,300	20,400	55,200	11,450
Dynamic head, ft	170	142	100	226	159	250	222
Design temp., °F	1000	700	1000	965	752	1085	675
Motor speed, rpm	900	1180 (MG set)	900	850	960	870	800
Motor power, hp	350	500 (MG set)	350	3000	750	3500	745
Sealing arrangement	Mechanical shaft seal	Total metal enclosure	Mechanical shaft seal	Mechanical shaft seal	Mechanical shaft seal	Mechanical shaft seal	Mechanical shaft seal
Material	304 SS	304 SS	2-1/4% Cr - 1% Mo	304 SS			
Type of speed control	Eddy current coupling	Variable Volt. (MG set)	Eddy current coupling	Eddy current coupling	Hydraulic coupling	WR/DC	Eddy current coupling

[a]Prototype FFTF pump/fabrication complete - January 1971
Prototype demonstration pump/fabrication complete - January 1972
500 FBR pump P.O. - January 1971.

The technology involved in the liquid-metal feedheater is similar to that developed for the intermediate heat exchanger (IHX) of the LMFBR. The liquid-metal operating conditions in Table 8.1 are comparable to those expected in the feedheater. The feedheater can operate at higher temperatures than those indicated because it is not limited by nuclear reactor temperatures.

Existing steam generators and IHXs have been operating at capacities in the order of 30 and 100 MWt per unit, respectively. The LMFBR program is designing them for 100 and 300 MWt per unit, respectively.

Initial estimates of liquid-metal flow rates and required pump heads indicate that a centrifugal pump will be selected according to pump state of the art. Figure 8.2 shows the range of flows and heads of existing liquid-metal pumps. The pumps of the LMFBR program, listed on Tables 8.2 and 8.3, provide additional information on centrifugal pump designs and operating conditions. The metal vapor Rankine topping cycle liquid-metal pump would be classified in the secondary pump parameter range, especially for the design head. The application of electromagnetic (EM) pumps is also a possibility.

Table 8.3 - Free Surface Sodium Pumps

Characteristics	SRE	HNPF
Capacity, gpm	2,500	7,200
Design Temperature, °F	1,200	1,000
Total Dynamic Head, ft	145	160
Motor Horsepower, hp	150	350
Hours of Operation	14,000	9,000

Table 8.4 lists the sizes and designs of liquid-metal valves which have been built and tested. These valves are of the order-of-

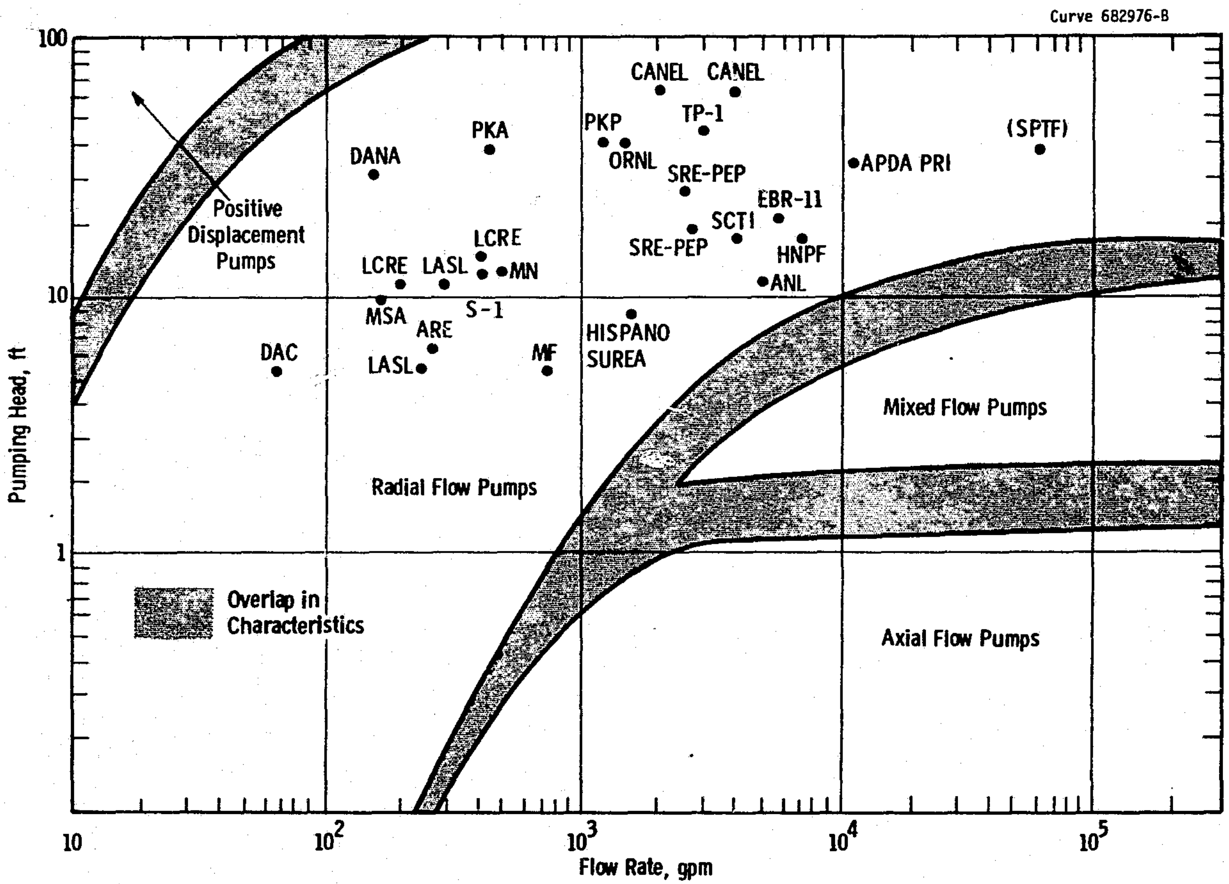

Fig. 8.2—Typical liquid metal pump characteristics

Table 8.4 - Large Valves in Liquid-Metal Cooled Reactors[a]

Reactor	Valve Function	Total Valves in Loop	Size, in	Stem Seal	Service Conditions: Approx. Temp., °F	Approx. Pressure, psi	Approx. Flow, gpm
EBR-I	Block	15	4, 6	Double bellows	600	20	291
ERB-II	Throttle	2	4	Close clearance	700	56	630
FERMI	Throttle	3	6	Double bellows	600	118	1,000
	Check	3	16	None	600	118	10,000
HALLAM	Block	9	14, 16	Freeze seal	950	57	6,750
	Check	3	16	None	610	37	6,750
SRE	Block	9	6	Bellows and freeze seal	850		
SRE-PEP	Block	4	4, 6	Bellows and freeze seal	1160	47	1,540
	Throttle	1	8	Torque tube	650	19	1,420

[a]All valves had stainless steel bodies.

Table 8.5 - Previous Studies

1. Condenser-Steam Generator
   - Westinghouse Primary Steam Generator Development Program
   - AI MSG Steam Generator Study
   - EBR-II

2. Liquid-Metal Feedheater
   - Foster Wheeler Corp. LMFBR and FFTF IHX Design Report
   - Fermi IHX
   - Hallam IHX
   - ALCO Sine-Wave IHX (SCTI)

3. Liquid-Metal Pumps
   - Westinghouse Large Sodium Pump Study
   - Fermi Pump
   - British PFR Pump
   - Hallam Pump
   - EM Pump Studies

4. Liquid-Metal Piping
   - Material Compatibility Studies
   - Piping Stress Analysis Codes
   - Pipe Hangers and Penetration Studies
   - Piping Insulation Selection Studies

5. Liquid-Metal Valves
   - Valve Development Program
   - Valve Operating Experience

6. Liquid-Metal Vapor Turbine
   - Two- and Three-Stage Potassium Turbine Test by General Electric
   - Potassium Turbine Tests by Garrett
   - Liquid-Metal Rankine Cycle Space Power Application

7. Inventory Control Development Programs for:
   - Level Instruments
   - Expansion Tanks, Dump Tank
   - Flowmeters
   - Temperature Instruments
   - Pressure Instruments
   - Leak Detectors

8. Liquid-Metal Purification Development Program for:
   - Liquid-Metal Solubility Studies
   - Hot and Cold Traps
   - Soluble Getters
   - Sampling Techniques
   - Chemical Analysis
   - EM Flowmeters
   - Plugging Meters
   - Electrochemical Meters

9. Trace Heating
   - Heater Development Program
   - Hanger and Insulation Development

magnitude size required for the metal vapor Rankine topping cycle. The LMFBR program is studying sodium valve development in order to improve on present valve capabilities.

In addition to the state of the art of mercury vapor turbines established for the mercury topping cycle power plants, much effort has been expended in space vehicle application of alkali-metal vapor turbines. The space program has also been investigating the feasibility of other liquid metals as working fluids for power generation.

Liquid-metal vapor turbines have been built and tested by General Electric for NASA and by Airesearch Manufacturing for the U. S. Air Force. A two-stage potassium turbine was operated successfully for 18 Ms (5000 hr) by General Electric.

The same may be said of liquid-metal inventory controls, purification systems, and trace heating: the technology exists. These systems have been built and tested for the Fermi, EBR-II, and Hallam in this country, and by several foreign nations. They have been designed for the Fast Flux Test Facility (FFTF), and many aspects of the systems have been tested in various facilities. Development programs are in progress to enhance the state of the art in these areas.

8.1.1 Previous Studies

As intimated previously, the steam generator studies for the LMFBR program provided information applicable to the condenser-steam generator. Table 8.5, Item 1, lists a few of the studies available. The Westinghouse Primary Steam Generator Development Program in particular provides an initial concept for design of the condenser-steam generator.

The design of the liquid-metal feedheater will closely resemble the IHX of the LMFBR program. Item 2 of Table 8.5 lists a design report and three actually built IHXs as reference studies.

Item 3 of the same table lists a Westinghouse study that provides liquid-metal pump design procedures, as well as sizing and costing information. Atomics International also has a similar study available, which is not listed. Under Item 3 are listed three centrifugal pumps which were built and tested. The final entry refers to the studies on EM pumps.

The EM pumps avoid the uncertainty of hydrostatic or hydrodynamic bearings operating in high-temperature liquid metal. EM pumps require no bearing, nor do they requires seals since there is no penetration of the liquid-metal envelope. The utilization of EM pumps would additionally simplify the liquid-metal transport system.

Item 4 of Table 8.5 is concerned with piping systems for liquid metals. One of the major requirements of such a system is the compatibility of the liquid metal with the piping material, as discussed in Section 4. Material is available from the LMFBR program and the metal vapor Rankine cycle program for space vehicle application. Also available under the LMFBR program are piping stress analysis codes and a Westinghouse development analysis procedure. Development programs are also involved with pipe hangers, penetrations, and insulation materials.

As mentioned previously, liquid-metal valve development programs are in progress using past operating experience as a guide. These are listed in Item 5.

Item 6 concerns previous studies on liquid-metal vapor turbines. Listed first are the two- and three-stage potassium turbine tests performed by General Electric under NASA CR-924 and NASA CR-1483, respectively. Also listed are the potassium turbine tests by Airesearch under contract to the Air Force.

Items 7, 8, and 9 of Table 8.5 cover the auxiliary system of inventory control, purification, and trace heating. Listed under the individual systems are developed programs for specific components and equipment required in the systems.

Uncertainties and development problems do exist in a liquid-metal system, but previous studies and testing programs have provided a good background for resolving them. Current FFTF and other LMFBR development programs are advancing the state of the art in these areas.

8.2 Basic Liquid-Metal Rankine Topping Cycle Plant

The parametric analysis of Task I for the liquid-metal Rankine topping cycle included 50 different plant designs, as shown in Table 8.6. The work scope specifically required that the analysis include pressurized fluidized bed combustion of coal and a pressurized furnace burning low-Btu gas made from coal. It was decided to incorporate two base cases in the parametric analysis: Base Case 1, a pressurized fluidized bed (PFB) plant, and Base Case 2, a pressurized furnace (PF) plant.

The plant site arrangement and size for Base Case 1 is shown as Figure 8.3. The plant island arrangement is illustrated on Figure 8.4 as supplied by Chas. T. Main, Inc., the architect/engineer. Figures 8.5 and 8.6 represent the plant site and plant island arrangement drawings for Base Case 2.

The flow schematics and location of state points for a PFB plant and a PF plant are shown in Figures 8.7 and 8.8, respectively. The components and flow paths denoted by dashed lines represent variations in the system configuration that were investigated. The base case system configurations are represented by solid-line components.

The configuration, performance, and state point values of Base Cases 1 and 2 are shown in Tables 8.7 and 8.8, respectively, for 1200 MWe size plants.

The base cases were assumed to be as simple as possible—hence the absence of recuperators, gas-heated feedwater heaters or economizers, and liquid-metal extractions. Based on availability studies for the liquid-metal fast breeder, plant availability is lower for sodium reheat steam cycles than nonreheat steam because of the increased probability of sodium/water reaction in the event of a steam tube rupture. Thus, a nonreheat steam cycle was selected for the two base cases.

A recirculating liquid-metal boiler was selected instead of a once-through boiler for the base cases in order to improve heat transfer coefficients and to mitigate possible overheating of the furnace tubes at

Dwg. 8505020

TABLE 8.6 – LIQUID METAL VAPOR RANKINE TOPPING CYCLE

	Compound Matrix								Parameter Matrix									
	Pressurized Combustor	Fuel	Recuperator Effectiveness	Liquid Metal Circulation Ratio	Liquid Metal Feedheater	Gas Feedwater Heater	Gas Economizer	Stages of Steam Reheat	Compressor Pressure Ratio	Air Equivalent Ratio	Gas Turbine Inlet Temperature °F	Liquid Metal Inlet Temperature (°F)	Liquid Metal Condenser Temperature (°F)	Steam Turbine Throttle Temperature (°F)	Steam Turbine Throttle Pressure (psig)	Steam Turbine Back Pressure (In. Hg. Abs.)	Cycle Power (MWe)	Liquid Metal
Variable Values	Press. Furnace Press. Fluid. Bed	Bituminous Sub-bit Lignite	0, 0.7, 0.8	1:1, 2.5:1	If Applicable	No, Yes	No, Yes	0, 1	5, 10, 15	1.2, 2.0, 3.0	1600, 1700, 1800	1400, 1500, 1600	1100, 1200, 1300	1000, 1100, 1200	3500, 2400	2, 3½, 9	400, 800, 1200, 1600	K, Cs
Case No.																		
1[1]	PFB	Bit	0	2.5:1	If Applicable	No	No	0	15	1.2	1800	1400	1100	1000	3500	3½	1200	K
2		Sub-bit																
3	↓	Lignite																
4	PF	Bit																
5		Sub-bit																
6	↓	Lignite																
7	PFB		0.7															
8	↓		0.8															
9	PF		0.7															
10	↓		0.8															
11	PFB			1:1														
12	PF			1:1														
13	PFB					Yes												
14	PF					Yes												
15	PFB						Yes											
16	PF						Yes											
17	PFB								5									
18	PFB								10									
19	PFB									2.0								
20										3.0								
21											1600							
22											1700							
23												1500	1200					
24												1600	1300					
25												1500	1200	1100				
26												1600	1300	1200				
27								1										
28								1				1500	1200	1100				
29								1				1600	1300	1200				
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38																2		
39																9		
40	PFB	Bit	0	2.5:1		Yes	No	1	15	1.2	1600	1400	1100	1000	3500	3.5	600	
41																	900	
42	↓																1600	
43	PF																600	
44																	900	
45	↓																1600	
46	FFC																1200	Cs
47																	600	
48	↓																1500	↓
49	PFB																1200	
50	PF	↓	↓	↓		↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	1200	

(1) Case No. 1 Is Base Case and All Blanks Have Same Value As Base Case

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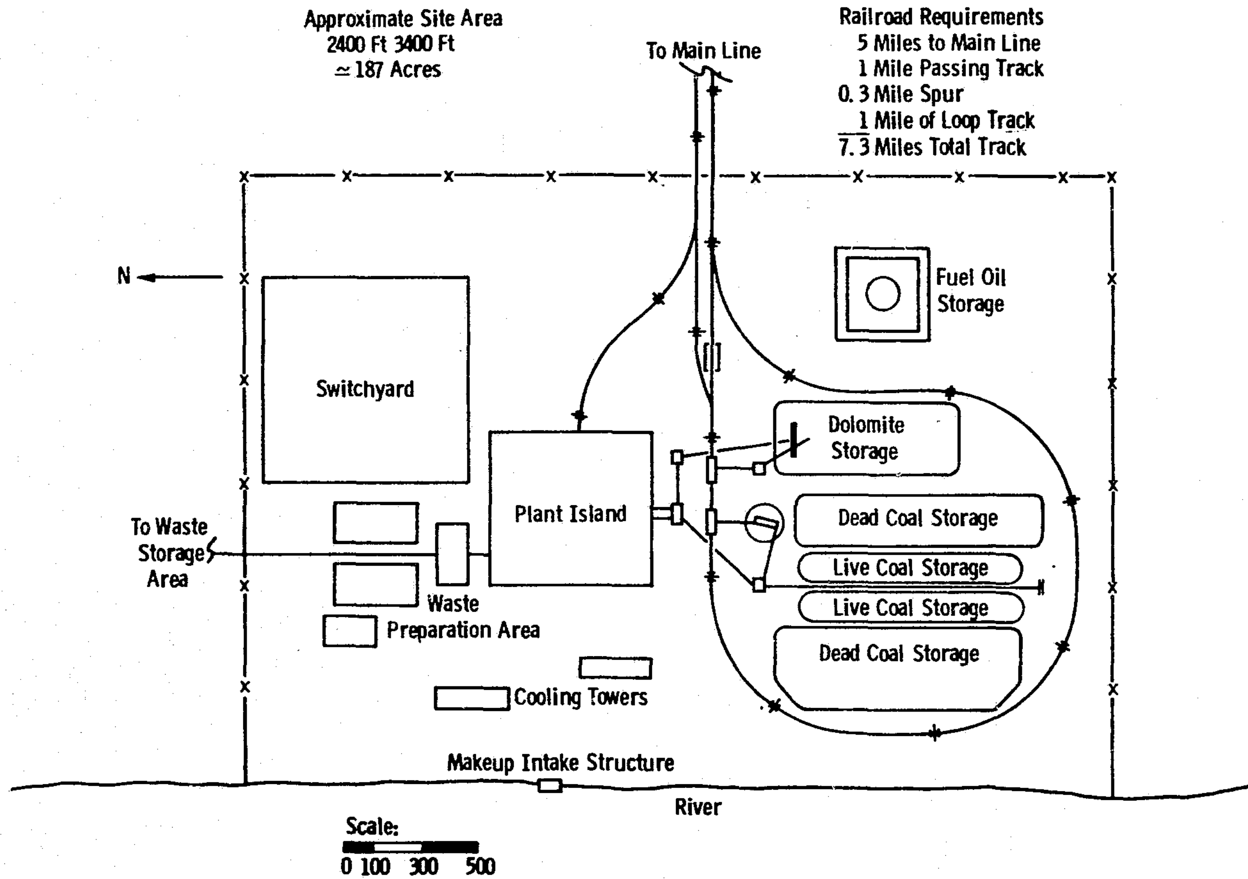
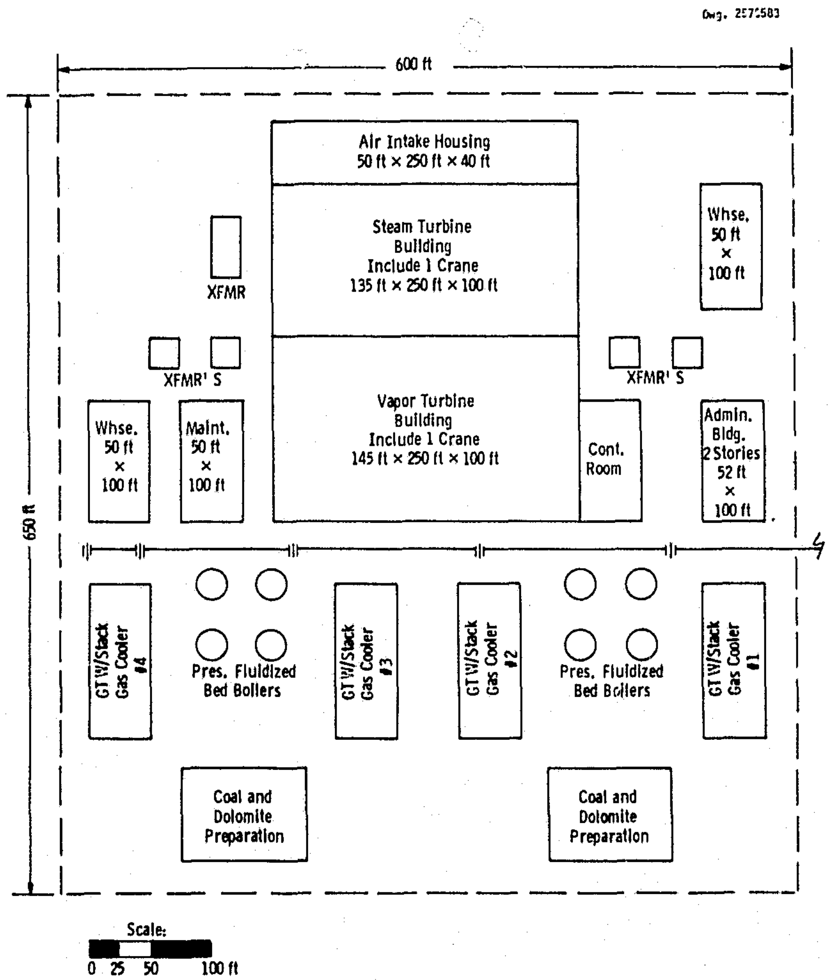


Fig. 8.3—Rankine metal vapor topping-steam bottoming cycle with pressurized fluidized bed boiler (Base Case 1)



Total = 1200 MW
STM = 700 MW
Vapor = 200 MW, 4 at 50 MW
GT = 300 MW, 4 at 75 MW

Fig. 8.4—Plant island arrangement for a metal vapor Rankine topping plant with a pressurized fluidized bed boiler

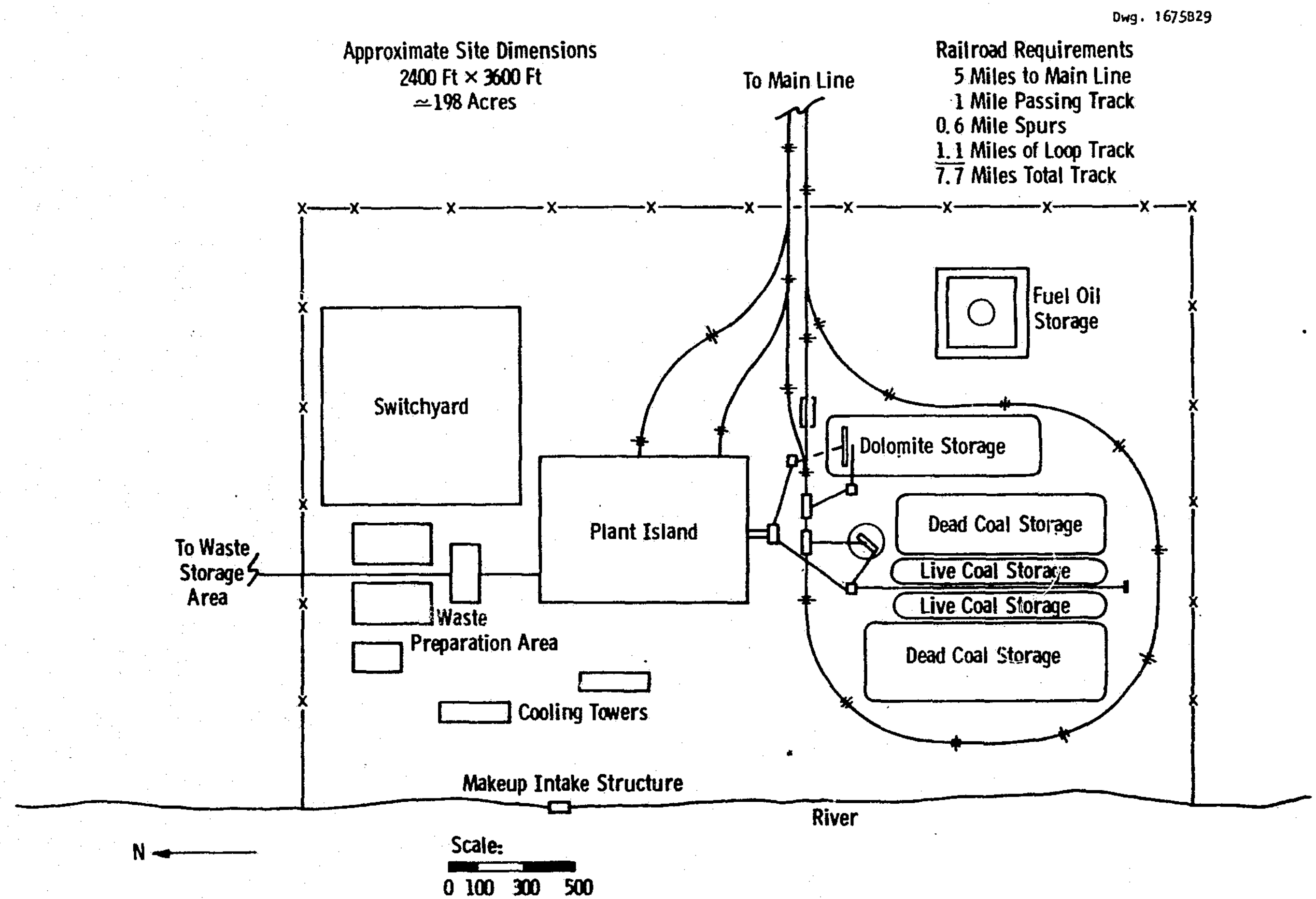


Fig. 8.5—Rankine metal vapor topping-steam bottoming cycle with a pressurized furnace (Base Case 2)

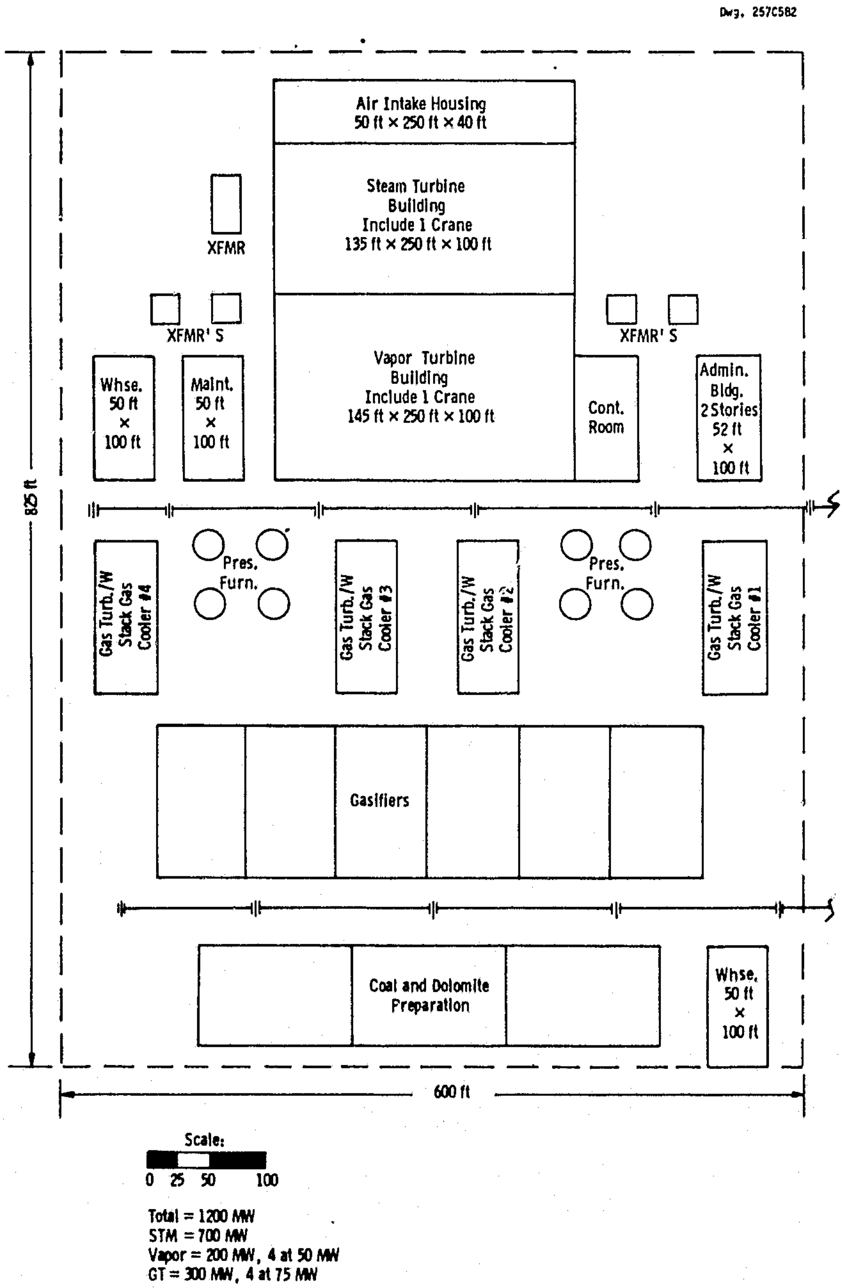


Fig. 8.6—Plant island arrangement for a metal vapor Rankine topping plant with a pressurized furnace and integrated coal gasifier

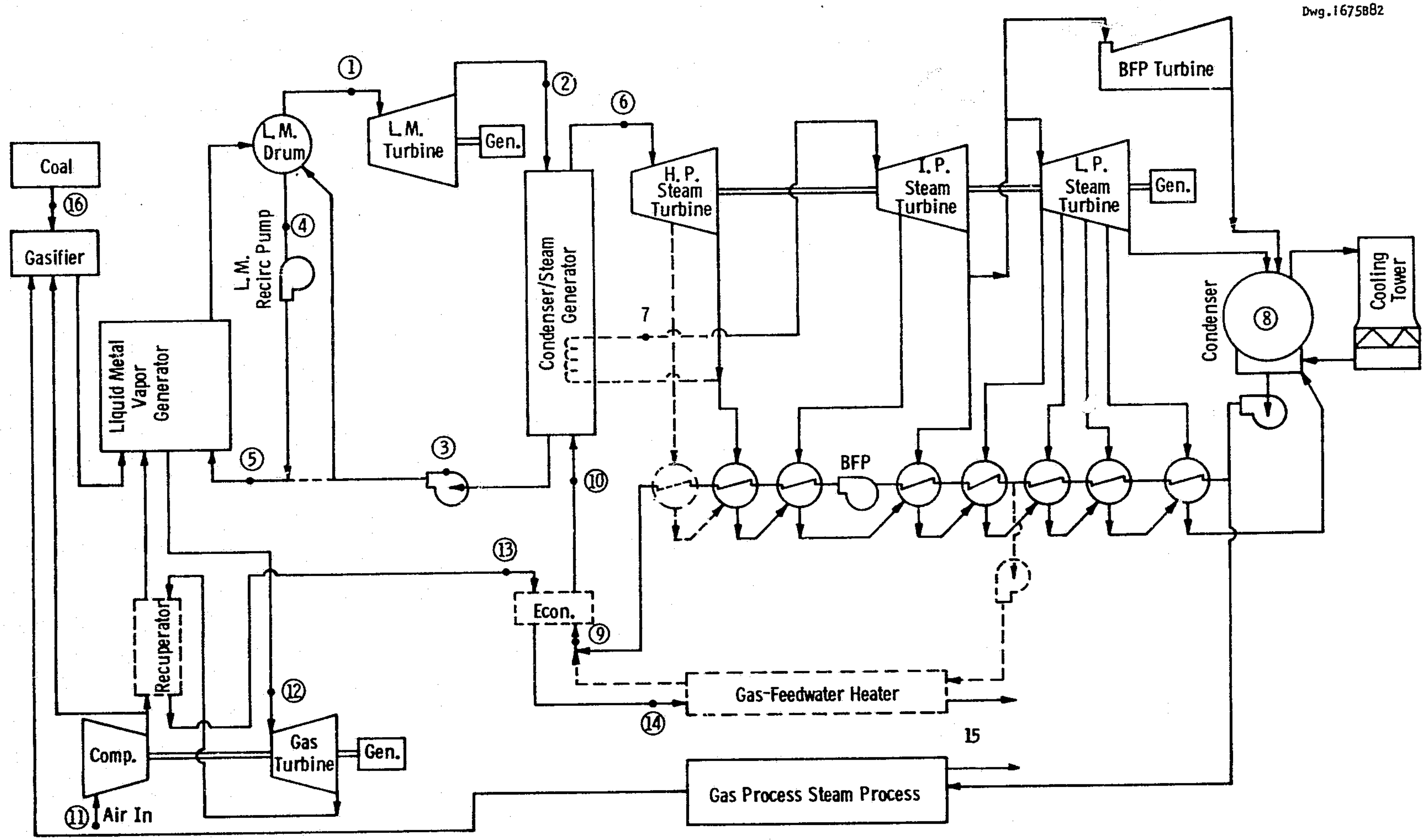


Fig. 8.7—Schematic liquid metal rankine topping cycle pressurized furnace

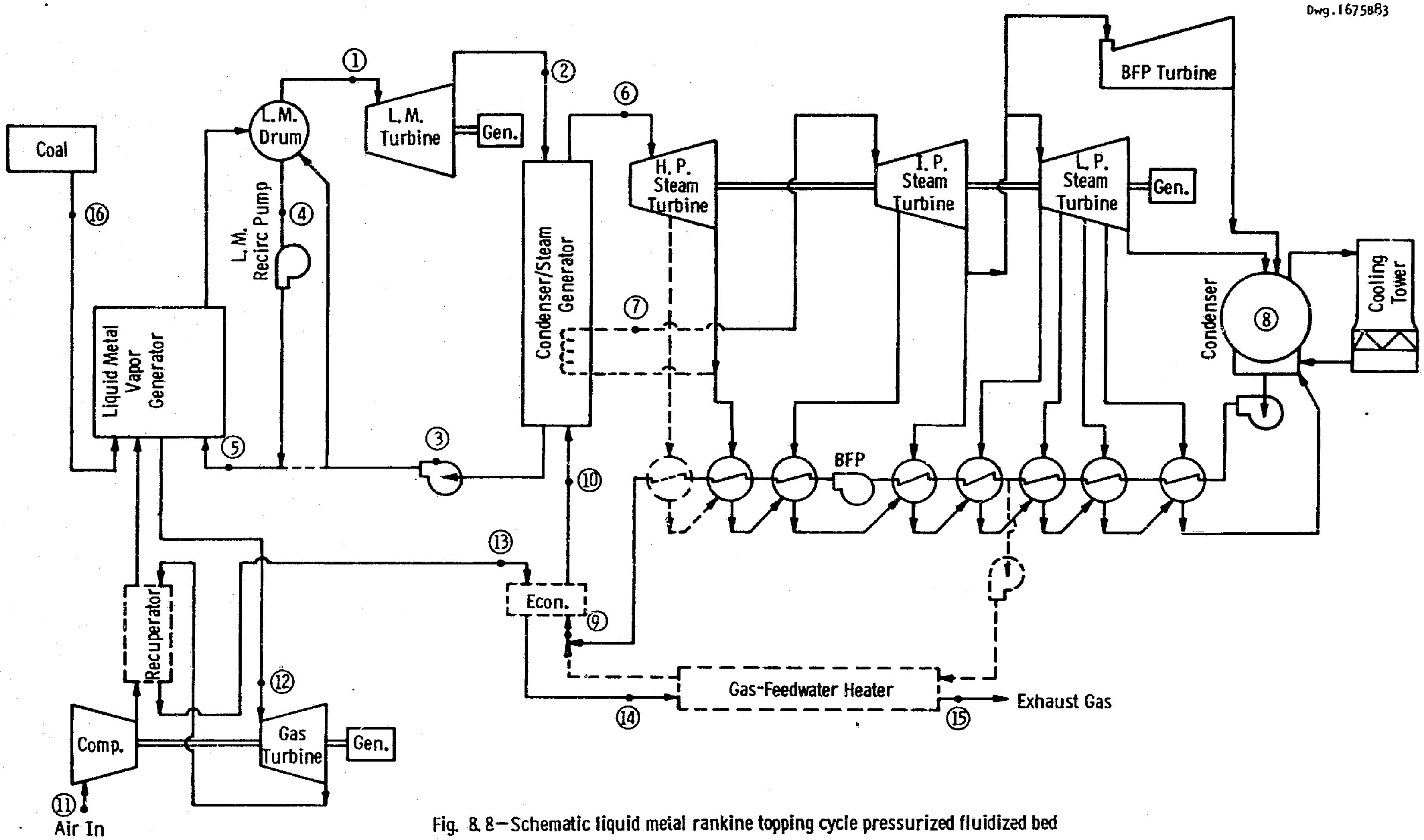


Fig. 8.8—Schematic liquid metal rankine topping cycle pressurized fluidized bed

Table 8.7 - Liquid-Metal Rankine Topping Cycle Components and Operating Parameters for Base Case 1

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.380
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.370
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.57
AIR EQUIVALENCE RATIO	1.2				

(The last four columns are printed under the heading "* * * * * * EFFICIENCIES * * * * *".)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.382	1400.000	15.200		188.000
2 L.M.CONDENSER		1100.000	2.400	5.856	
3 L.M.FEED PUMP	5277.000 GPM	1100.000	33.900		.363
4 L.M.RECIRC PUMP	13574.000 GPM	1280.000	20.610		.173
5 L.M.BOILER INLET		1280.000		6.600	
6 STEAM TURBINE THROTTLE	6.774	1000.000	3515.000		720.600
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.396	
9 FINAL FEEDWATER		560 .000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.320	59.000	14.690		
12 GAS TURBINE INLET	11.216	1800.000			291.500
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	499.400T/HR			10.775	

Table 8.8 - Liquid-Metal Rankine Topping Cycle Components and Operating Parameters for Base Case 2

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET		****** EFFICIENCIES *****	
FURNACE	PR. FURNACE	TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.037
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.263
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.365
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.356
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.88

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.327	1400.000	15.230		186.500
2 L.M.CONDENSER		1100.000	2.400	5.813	
3 L.M.FEED PUMP	5245.000 GPM	1100.000	33.590		.356
4 L.M.RECIRC PUMP	13491.000 GPM	1260.000	20.550		.170
5 L.M.BOILER INLET		1280.000		6.551	
6 STEAM TURBINE THROTTLE	6.724	1000.000	3515.000		715.300
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.372	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.056	59.000	14.690		
12 GAS TURBINE INLET	10.960	1800.000			298.600
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		857.000			
16 AS RECEIVED COAL	520.000T/HR			11.220	

the hot end. Recirculation also provides for easier start-up and control, and reduction of mass transfer and corrosion. A recirculation ratio of 2.5 to 1 was selected because, for the heat fluxes estimated in the vapor generators, departure from nucleate boiling (DNB) occurred at approximately 50% quality. The recirculation ratio of 2.5 to 1 corresponds to 40% quality entering the metal vapor drum and provides sufficient conservatism to avoid the problems of DNB and film boiling in the liquid-metal vapor generators.

The recirculation ratio is defined as the ratio of total liquid-metal flow through the furnace/boiler divided by the feed flow.

A gas turbine inlet temperature of 1255°K (1800°F) was selected as the maximum temperature allowed for pressurized fluidized bed combustion of coal to avoid melting and agglomeration of the ash. In conjunction with the liquid-metal temperatures selected, the 1255°K (1800°F) temperature tended to minimize the PFB and PF heat transfer areas and, hence, minimize capital cost.

A potassium vapor turbine inlet temperature of 1033°K (1400°F) provided a reasonable turbine throttle pressure, 104.8 kPa (15.2 psi) abs. Since the PFB and PF are limited to overall heat transfer coefficients approximately equal to the flue gas coefficients [< 283 W/m^2-°K (< 50 Btu/hr-ft^2-°F)], the log mean temperature difference is maximized with 1033°K (1400°F) liquid metal. Reduction below 1033°K (1400°F) would result in a subatmospheric throttle pressure for the liquid-metal turbine. The liquid-metal condensing temperature of 866°K (1100°F) provided a reasonable condenser pressure [16.55 kPa (2.4 psi) abs] and condenser/steam generator hot-end temperature difference.

The steam turbine throttle conditions of 24.132 MPa (3500 psi) abs, 811°K (1000°F) provide high steam cycle efficiency. The supercritical pressure eliminates potential problems of tube fatigue and uncertainties associated with DNB. The 11.85 kPa (3-1/2 in Hg) abs back pressure represents wet cooling tower conditions. Wet towers are environmentally more acceptable than are once-through and more economical for heat rejection than are dry cooling towers.

Potassium was selected as the working fluid because more data were available. For this reason the study concentrated on the effects of component and parameter variations on a potassium subsystem, assuming that the results of a potassium subsystem would apply to cesium as well.

8.3 Method of Performance Calculation

The performance of the metal vapor Rankine topping-steam bottoming cycle was calculated by a combination of computer codes and hand calculation. Computer codes were used for the performance of the steam turbine subsystem and the pressurized combustor subsystem, and hand calculations determined the performance of the liquid-metal subsystem.

The hand calculation of the metal vapor turbine was based on an isentropic expansion turbine efficiency of 78%. For an inlet condition of 1033°K (1400°F) and 99% quality, the potassium vapor left the turbine at 866°K (1100°F) and 90% quality. Approximately 202 kJ/kg (∿ 87 Btu/lb) of useful work could be extracted from the potassium by expansion through a turbine for the above conditions. The amount of useful work for the 1089°K/922°K (1500°F/1200°F) turbine-condenser conditions and the 1144°K/978°K (1600°F/1300°F) turbine-condenser conditions was assumed to be approximately the same as for the 1033°K/866°K (1400°F/1100°F) cycle.

Further calculations on a volumetric flow basis demonstrated that a 25 MWe potassium turbine would be of a double-flow, four-stage design with a 1.82 m (6 ft) diameter disk and run at 30 rps (1800 rpm). The cesium turbine was designed for the same 1033°K/866°K (1400°F/1100°F) turbine-condenser conditions, with 90% exhaust quality and a 76% efficiency. The useful work for these conditions was calculated to be ∿ 61.2 kJ/kg (∿ 26.3 Btu/lb).

The performance of the pressurizing combustor subsystem was evaluated by computer program using the pressurized combustor type, the coal type, recuperator effectiveness, the compressor pressure ratio, air equivalence ratio, and gas turbine inlet temperature as denoted for the 50 parametric points of the metal vapor Rankine topping cycle of Table 8.6. The output included the quantities of heat available from the combustor, Q_b/W_a; the stack-gas cooler, Q_2/W_a; and the power generated by the gas turbine generator, P/W_a, as a function of the airflow rate, W_a, and the fuel-to-air ratio, W_f/W_a.

The steam turbine subsystem efficiencies, as determined by computer code, were based on the steam turbine throttle temperatures and pressure and condenser back pressures given in Table 8.6. All cases utilized an 800 MWe steam turbine. The final feed temperatures were 566 and 550°K (560 and 530°F) for 24.132 and 16.547 MPa (3500 and 2400 psi) gauge conditions, respectively, with eight feedwater heaters. For the case which utilized a gas feedwater heater in parallel with the turbine feedwater train, the final feed temperature was 529°K (492°F) with seven feedwater heaters. The stack outlet temperature, total flue gas flow, and flue gas composition were included as input. For cases with steam reheat the reheat temperature was assumed equal to the steam throttle temperature, and the IP turbine inlet pressure was always taken as 4.137 MPa (600 psi) abs.

The integration of the three subsystems was performed by simple hand calculation in an iterative process. Assuming the metal vapor turbine-generator produced 100 MWe, P_{LMT}, with a known useful work, ΔH_{LMT}, the liquid-metal flow rate, W_{LM}, is:

$$W_{LM} = P_{LMT}/\Delta H_{LMT} \tag{8.1}$$

For any given metal vapor cycle the liquid-metal enthalpy rise in the boiler, ΔH_b, and enthalpy drop in the condenser-steam generator, ΔH_c, are known. So with W_{LM} of Equation 8.1 the heat available to the boiler, Q_b, is:

$$Q_b = W_{LM}\ \Delta H_b \tag{8.2}$$

and the heat rejected to the steam, Q_c, is:

$$Q_c = W_{LM}\ \Delta H_c \tag{8.3}$$

For the pressurizing combustor subsystem performance values, the airflow rate, W_a, is:

$$W_a = \frac{Q_b}{(Q_b/W_a)} \tag{8.4}$$

and the power generated by the gas-turbine generator, P_{gt}, is:

$$P_{gt} = (P/W_a)\ W_a \tag{8.5}$$

In the case of a gas economizer or feedwater heater, the heat transferred in the stack-gas cooler, Q_2, is:

$$Q_2 = (Q_2/W_a)\ W_a \tag{8.6}$$

If there is no gas economizer or feedwater heater, then Q_2 is 0. To determine the power produced by the steam-turbine generator, the total heat added to the steam-turbine subsystem, Q_{stm}, is:

$$Q_{stm} = Q_c + Q_2 \tag{8.7}$$

and using the steam-turbine cycle efficiencies, η_{stm}, as determined by computer code, the steam-turbine rating, P_{stm}, is:

$$P_{stm} = (Q_{stm})\ \eta_{stm} \tag{8.8}$$

The summation of the power generated by the three subsystems is the total plant power, P_{total}. In order to determine the liquid-metal and airflows, the thermal loads, and the three subsystem power ratings of a 1200 MWe rated plant, a new liquid-metal flow rate, W'_{LM}, was calculated from Equation 8.9:

$$W'_{LM} = W_{LM} \, (1200/P_{total}) \tag{8.9}$$

Letting W_{LM} equal W'_{LM}, the above procedure, Equations 8.2 through 8.8, was repeated.

Once the reiteration is completed, the remaining flow rates needed to size equipment can be calculated. The steam throttle flow rate, W_{stm}, was calculated as:

$$W_{stm} = \frac{Q_c + Q_2}{\Delta H_{cs} + \Delta H_2} \tag{8.10}$$

where ΔH_2 is the water enthalpy rise in the gas economizer and/or gas feedwater heater.

In order to optimize the amount of heat input for a gas economizer with the cost of the heat exchanger, estimates indicate that ∿ 50% of the heat available at the stack-gas cooler, Q_2, should be used to economize the feedwater going to the condenser-steam generator. Obviously, all of Q_2 cannot be available for economizing, since the exhaust stack-gas temperature 416°K (290°F) is lower than the final feedwater temperature of 529°K (492°F).

The water-steam enthalpy rise, ΔH_c, in the condenser-steam generator includes the enthalpy rise for the throttle steam flow and the reheat steam flow. A good approximation of the water enthalpy rise is defined by:

$$\Delta H_{cs} = \Delta H_{stm} + C \; \Delta H_{rh} \tag{8.11}$$

Table 8.9 - Heating Values of Coals with Various % Moistures

Coal	Illinois Bituminous	Montana Subbituminous	North Dakota Lignite
As Received			
Moisture, % (Moist1)	13.0	24.3	36.7
HHV, Btu/lb	10788	8944	6890
LHV, Btu/lb	10230	8372	6248
Lockhopper			
Moisture, % (Moist2)	3	20	27
HHV, Btu/lb	12028	9452	7946
LHV, Btu/lb	11525	8907	7365
Maximum Practicable Drying			
Moisture, % (Moist3)	0	16	18
HHV, Btu/lb	12400	9925	8926
LHV, Btu/lb	11913	9405	8401

where ΔH_{stm} is the throttle steam enthalpy rise above that at the economizer exit, ΔH_{rh} is the reheat steam enthalpy rise, and C is a constant which varies from 0.88 to 0.895, depending on throttle conditions.

This approximation of the high-pressure turbine extraction steam flow agrees within ± 3% for computer-calculated performance values. The flue gas flow rate, W_g, based on the fuel/air ratio, W_f/W_a, which is given in the pressurizing combustor subsystem performance, is:

$$W_g = [1 + (W_f/W_a)]\ W_a \tag{8.12}$$

and the as fired coal flow, W_f, is:

$$W_f = (W_f/W_a)\ W_a \tag{8.13}$$

The as received coal flow rate depends on the type of coal used and the type of combustor. For a pressurized fluidized bed the as received coal use rate, tons/hr, is:

$$\text{Tons/hr} = W_f \left(\frac{1\text{-Moist2}}{1\text{-Moist1}}\right) \tag{8.14}$$

where Moist1 and Moist2 are listed in Table 8.9 for the three types of coal considered. For a pressurized furnace the coal use rate is:

$$\text{Tons/hr} = W_f/(1.0\text{-Moist1}) \tag{8.15}$$

where Moist1 is also listed in Table 8.9. For a pressurized fluidized bed the total heat input of the plant Q_{total} is determined by:

$$Q_{total} = (\text{Tons/hr})\ \text{HHV} \tag{8.16}$$

where HHV, the higher heating values of the three coals, are listed for the various moisture contents in Table 8.9.

The gasification subsystem for a pressurized furnace plant requires heat for drying the coal, and process steam and air for the production of low-Btu fuel gas. It was assumed that these heating requirements were satisfied by the hot exhaust flue gas from the pressurizing combustor subsystem at the stack-gas cooler, Q_2. When a gas economizer was used to add heat in the steam turbine subsystem, approximately half the heat available at the stack-gas cooler, Q_2, was used to economize the feedwater. The other half of Q_2 was assumed sufficient to satisfy the drying and process heat requirements of the gasification subsystem.

For a case where a gas feedwater heater was used in parallel with the extraction feedwater heater string, the process steam requirement was not satisfied (see Table 8.6 Cases 14, 43, 44, 45, and 50). The process steam heat, Q_{ps}, then was assumed to be an added thermal load on the pressurized furnace plant. The process steam rate, W_{ps}, was determined as:

$$W_{ps} = (W_{ps}/W_a)\ W_a \qquad (8.17)$$

where (W_{ps}/W_a), was calculated by the pressurizing combustor subsystem performance computer code for a pressurized furnace.

The thermal load of the process steam, Q_{ps}, was evaluated by:

$$Q_{ps} = W_{ps}\ \Delta H_{ps} \qquad (8.18)$$

where ΔH_{ps} was the water enthalpy rise from the enthalpy at the steam condenser to the enthalpy of saturated steam at a saturation pressure 1.5 times the pressurized furnace operating pressure. [For the applicable cases this saturation pressure was 1.5 times 1.520 MPa (15 atm), or P_{sat} is 2.28 MPa (330 psi) abs.] Hence, for cases 14, 43, 44, 45, and 50 of Table 8.6, the total heat input of the plant was:

$$Q_{total} = (Tons/hr)\ HHV + Q_{ps} \qquad (8.19)$$

The gross plant cycle efficiency, η_{Gross}, then, was given by:

$$\eta_{Gross} = P_{total}/Q_{total} \qquad (8.20)$$

where Q_{total} is given by Equation 8.16 for PFB and by Equation 8.19 for PF. With the various subsystem flows evaluated, the parametric points of the liquid-metal subsystem components were sized for each of the parametric points of Table 8.6.

8.4 Results of the Parametric Study

8.4.1 Matrix of Component and Parameter Variations

The work scope of this study required the metal vapor Rankine topping cycle to be investigated for a variety of furnace combustor types, fuel (coal types), cycle configurations, major cycle parameters, and power levels. The matrix of the 50 parametric points for the metal vapor Rankine topping cycle is shown on Table 8.6. Base Case 1, the pressurized fluidized bed, and Base Case 2, the pressurized furnace-gasifier system, are listed in Table 8.6 as Points 1 and 4, respectively.

The first 39 cases served as a sensitivity study to determine the effects of component and parameter variation for a constant power level. This sensitivity study was then used to determine a preliminary optimum case by combining the components and parametric values which individually provided the best cycle performance and which were estimated to be cost effective. This preliminary optimum cycle was used to determine the effect of power level variation for a PFB plant (Points 40, 41, 42, and 49) and a PF plant (Points 43, 44, 45, and 50). Points 46, 47, and 48 were used to study the effects of power-level variation and cesium as the working fluid in a PFB plant.

Table 8.10 - Effect on Cycle Performance of PFB and PF Plants for Parameter and Component Variation

Component/Parameter	Overall Energy Efficiency, %			
	PFB	Point No.	PF	Point No.
Coal Type				
Illinois No. 6 bituminous	35.9	1	35.0	4
Montana subbituminous	35.8	2	38.1	5
North Dakota lignite	34.8	3	38.8	6
Recuperator Effectiveness				
$\varepsilon = 0.0$	35.9	1	35.0	4
$\varepsilon = 0.7$	36.4	7	35.3	9
$\varepsilon = 0.8$	36.4	8	35.4	10
Recirculation Ratio				
25:1	35.9		35.0	
1:1 (once through)	35.9	11	35.0	12
Gas Feedwater Heater	43.4	13	40.9	14
Gas Economizer	39.7	15	38.8	16

8.4.2 Effect of Furnace-Combustor Type

The effect of furnace-combustor type (PFB and PF) on performance was investigated, while varying several other parameters and components. Table 8.10 lists the parameter and components varied for both furnace-combustor types and the resulting overall energy efficiency. In all cases except the Montana and North Dakota coal cases, the PFB shows a higher efficiency. The lower PF efficiency is due to the 90% efficiency of the integrated gasifier producing low-Btu gas from the coal.

8.4.3 Effect of the Gas Turbine Recuperator Effectiveness, ε

The effect of preheating air at the inlet to the furnace-combustor with the gas turbine exhaust was determined for recuperator effectiveness of $\varepsilon = 0.7$ and $\varepsilon = 0.8$. The addition of a recuperator to the PFB raised the air inlet temperature 33.3 and 38.9°K (60 and 70°F) for an effectiveness of 0.7 and 0.8, respectively, over Base Case 1, which had no recuperation. The preheating reduced the required airflow and the power split in the cycle to improve the overall efficiency 1.4% above Base Case 1. For the PF plant the air temperature was raised 38.9 to 44.4°K (70 to 80°F) for 0.9 and 1.1% efficiency improvement for effectiveness of $\varepsilon = 0.7$ and $\varepsilon = 0.8$, respectively.

It was assumed that the recuperators would not be cost effective for the small efficiency improvements. Furthermore, the 22.2 to 27.8°K (40 to 50°F) drop in recuperator exhaust gas temperature would reduce the effectiveness of the gas-heated economizer and/or feedwater heaters and increase their cost. The recuperators were not, therefore, incorporated into the preliminary optimum.

8.4.4 Effect of Liquid-Metal Recirculation

As shown on Table 8.6, both once-through and recirculating liquid-metal boiler subsystems were studied. The cycle efficiency for the once-through system was negligibly higher than the recirculating system. The liquid-metal recirculation pumps required 0.17 MWe (less than 0.015%) of the net power output.

The once-through unit will cost less due to smaller liquid-metal inventory, storage tanks, and the absence of recirculation pumps, piping, and vapor drum. The recirculation ratio of 2.5 to 1 was selected to avoid DNB and all its subsequent problems. Recirculation also provides for easier control and a heated makeup inventory in case of loss of water flow for any reason. For these reasons the recirculating boiler system was selected for the preferred case.

8.4.5 Effect of Exhaust Gas Feedwater Heaters and Economizers

For Base Cases 1 and 2 the combustor pressurizing subsystem turbine exhaust gas was assumed to be used to provide process heat to other subsystems (such as process steam in the PF gasifier plant). In the case of the gas-heated feedwater heaters, all the heat available from the stack-gas coolers was transferred to the feedwater.

The resulting cycle efficiencies of 43.4 and 40.9% for the PFB and PF, respectively, were the highest found. The PFB plant efficiency increased 20.9% over Base Case 1; and the PF plant efficiency increased 16.9% over Base Case 2. The PF increase was not as large as the PFB case due to the gasifier process steam requirements. Because of the economizer exhaust gas temperature limitation imposed by the final feedwater temperature of 529°K (492°F), the exhaust gas transferred approximately half the available stack-gas cooler energy to the gas-heated economizer. The performance improvement was still significant (half the amount of the feedwater heaters), 10.6% for the PFB and 10.9% for the PF. In the case of the PF the process steam requirements were supplied by the remaining available stack-gas cooler energy.

It was assumed that incorporation of both the gas feedwater heater and the economizer would not be cost effective. The larger increase in overall efficiency due to the gas-heated feedwater heater was the basis for its selection as optimum. Preliminary calculations, however, indicate that there is too much heat available in the gas feedwater heater with the assumed 529°K (492°F) maximum feedwater temperature. With this assumption the feedwater flow to the turbine extraction feedwater heater string is greatly reduced. The resulting low-pressure steam turbine exhaust flows are, therefore, larger than for full extraction machines, thereby causing large exhaust losses if the same low-pressure ends were chosen; or the use of larger, more costly ends if this is unacceptable. Reduced steam turbine efficiencies were assumed when a gas feedwater heater was incorporated. A logical optional approach would have been to remove the 529°K (492°F) assumed maximum feedwater temperature.

8.4.6 Effect of Compressor Pressure Ratio

Calculations were performed for combustor pressurizing subsystem pressure levels of 0.506, 1.013, and 1.520 MPa (5, 10, and 15 atm). The resulting overall energy efficiencies increased with increasing pressure ratio, as shown on Figure 8.9. On the basis of efficiency, the 15-to-1 compressor ratio was selected for the preliminary optimum plant.

On the other hand, a compressor pressure ratio of 10 to 1 results in a stack-gas cooler gas inlet temperature 311°K (100°F) higher than a 15-to-1 pressure ratio. There is also approximately 22% more stack-gas cooler energy available to the more efficient steam turbine by means of the gas feedwater heater and/or gas economizer. The effect on overall energy efficiency for a compressor pressure ratio of 10 to 1 with a gas feedwater heater and/or a gas economizer warrants further investigation.

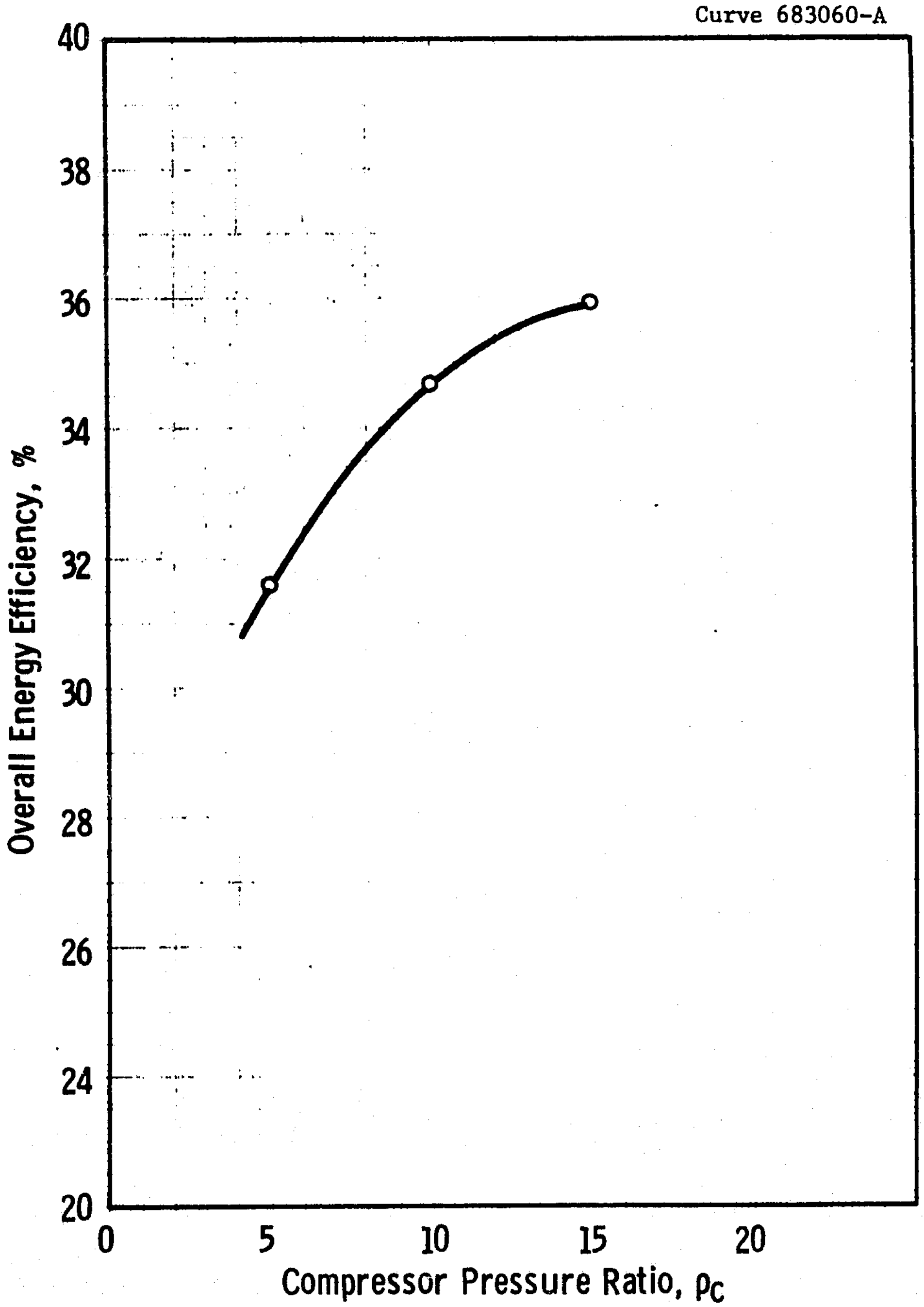


Fig. 8.9—Effect compressor pressure ratio on overall energy efficiency for a pressurized fluidized bed boiler plant

Similarly, the energy available to the steam turbine may be increased by preheating the air to the furnace combustor and lowering the compressor pressure ratio to 10 to 1. Under these conditions the condenser-steam generator heat available to the steam turbine increases approximately 10%. The stack-gas cooler heat available decreases accordingly. Reduction in the amount of gas feedwater heating is in the proper direction for obtaining the optimum flow split through the parallel gas feedwater and the extraction feedwater string (mentioned in Subsection 8.4.5).

The present study has investigated the effects of individually and separately varying such components and parameters as recuperators, gas economizers, gas feedwater heaters, and compressor pressure ratios. The optimum plant configuration and parameters, however, can only be obtained by investigating the above parameters and components in combination, a task beyond the scope of Task I of this study.

8.4.7 Effect of Air Equivalence Ratio

Three values of air equivalence ratio, ϕ_{air}, were investigated. The minimum ϕ_{air} of 1.2 for fluidized bed combustion was used for Base Cases 1 and 2. Additional values of ϕ_{air} used were 2.0 and 3.0. As shown on Figure 8.10, the overall energy efficiency decreases drastically as ϕ_{air} increases above $\phi_{air} = 1.2$. As the airflow increases, less energy is available to heat the liquid metal. At a ϕ_{air} of 1.2, approximately 40% of the available heat is required to heat the air. At a ϕ_{air} of 2.0 almost 75%; and at a ϕ_{air} of 3.0 fully 90% of the heat available is heating the air (see Figure 8.10). The base case ($\phi_{air} = 1.2$) was selected as optimum.

8.4.8 Effect of Gas Turbine Inlet Temperature

The maximum allowable fluidized bed temperature is 1283°K (1850°F) because of the desulfurization reaction. Therefore, the maximum gas turbine inlet temperature selected was 1255°K (1800°F). Turbine inlet temperatures of 1144 and 1200°K (1600 and 1700°F) were also studied. The overall energy efficiency increased as the gas turbine inlet temperature decreased, as shown on Figure 8.11. The efficiency increased 6% as

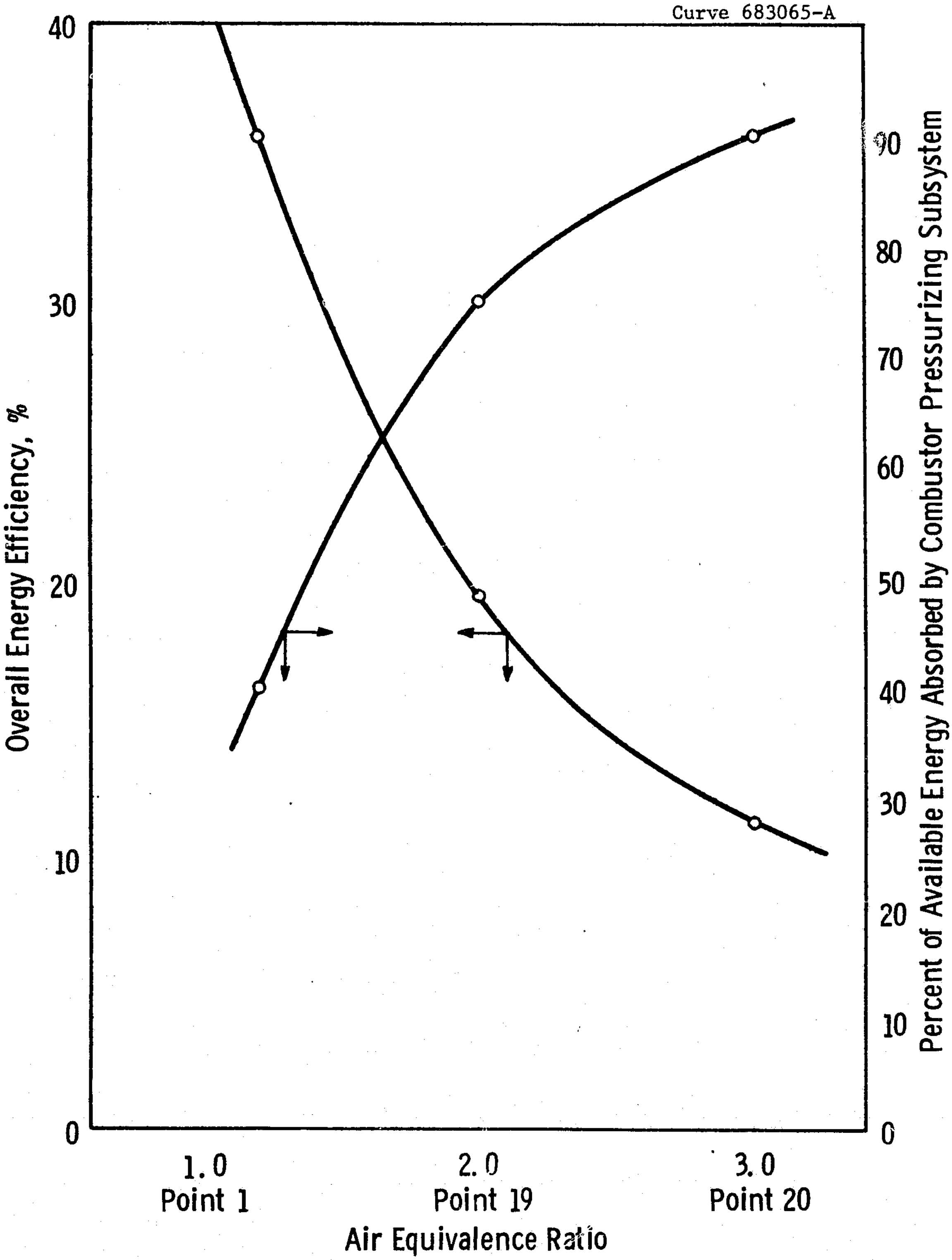


Fig. 8.10—Effect of air equivalence ratio variation on overall energy efficiency for a pressurized fluidized bed boiler plant

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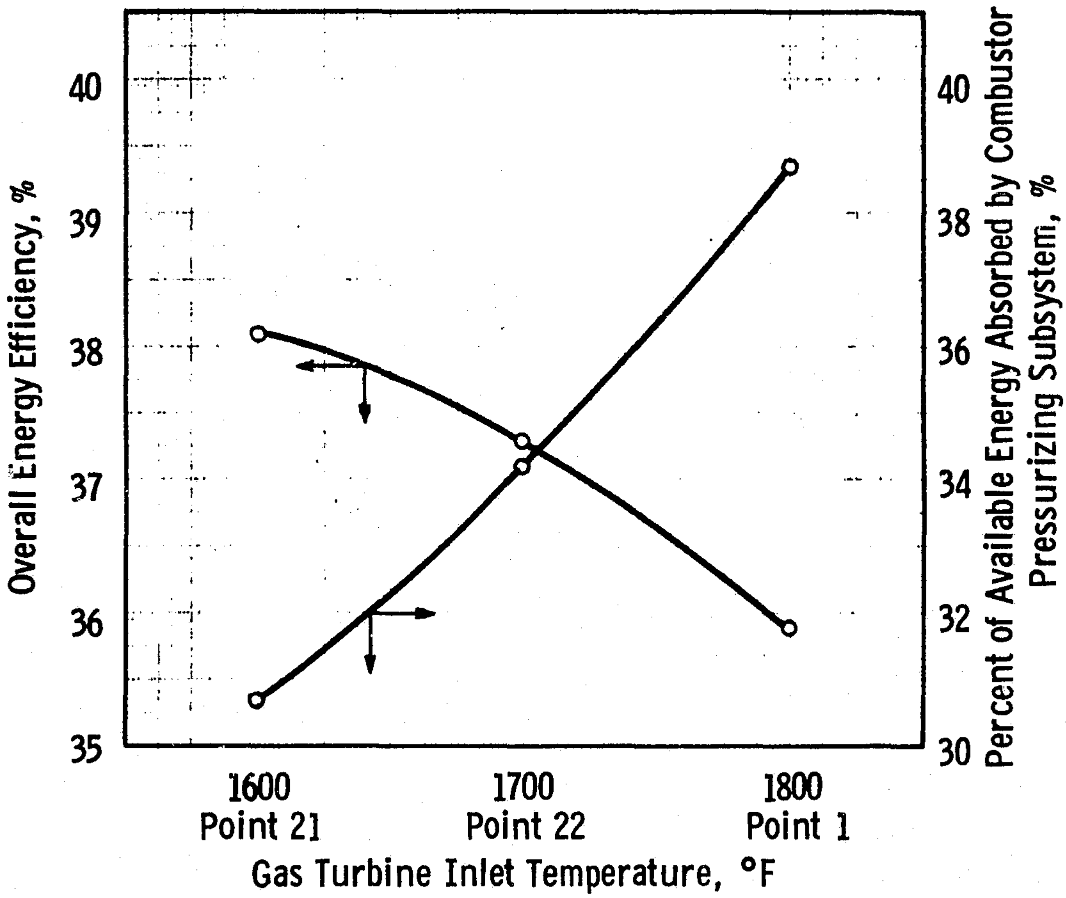

Fig. 8.11 —Effect of gas turbine inlet temperature on overall energy efficiency for a pressurized fluidized bed boiler plant

the gas turbine inlet temperature was reduced from 1255 to 1144°K (1800 to 1600°F). This improved efficiency was the result of reducing the percentage of the total available energy absorbed by the combustor pressurizing subsystem. As the gas turbine inlet temperature was lowered, more of the available energy was transferred to the more efficient steam turbine. Figure 8.11 also shows the percent of available energy absorbed by the pressurizing subsystem as a function of temperature.

On the basis of overall efficiency the 1144°K (1600°F) gas turbine inlet temperature was selected as optimum. As will be demonstrated in Subsection 8.6, however, a lower gas turbine inlet temperature at the same pressure ratio reduces the log mean temperature difference in the stack-gas coolers which transfer energy to the steam turbine feedwater, thus increasing the cost of electricity for this plant. The interaction of gas turbine inlet temperature with stack-gas coolers and recuperators is as significant as is compressor pressure ratio. Again, an optimum plant cannot be determined until the interaction of the parameters and components of the combustor pressurizing subsystem has been investigated thoroughly.

8.4.9 <u>Effect of Metal Vapor Turbine Inlet Temperatures</u>

In studying the effect of liquid-metal temperature variation, a constant 166.7°K (300°F) temperature difference was maintained from liquid-metal turbine inlet to the condenser-steam generator. The liquid-metal temperature variations investigated were 1033°K inlet/866°K outlet (1400°F/1100°F), 1089°K/922°K (1500°F/1200°F), and 1144°K/978°F (1600°F/1300°F). The effect of this variation on overall energy efficiency was negligible. The efficiency improved only 0.3% over the entire range (see Figure 8.21b). The Base Case 1 liquid-metal temperatures of 1033°K/866°K (1400/1100°F) were selected for the preliminary optimum case. The lower temperatures tend to mitigate high-temperature material and development problems.

To fully appreciate liquid-metal system temperature variation effects, the effect of liquid-metal temperature differences should be investigated. The liquid-metal turbine preliminary design calculations, however, indicated that the pressure drop through a moisture separator or reheater were unacceptable. Preliminary studies further indicated that internal moisture separation was not practical due to the low-turbine speeds. The liquid-metal turbine temperatures were based on these considerations and a maximum 10% moisture. Additional effort in the turbine design area should rectify these difficulties.

8.4.10 Effect of Steam Throttle Temperature

The steam throttle temperatures of 811, 866, and 922°K (1000, 1100, and 1200°F) were investigated. Unlike the previous parameter variations, the steam temperature was not varied separately but was varied with the liquid-metal temperature. In each case a 55.5°K (100°F) temperature difference was assumed between the liquid-metal condensing temperature and the steam turbine throttle temperature. The results of the steam turbine throttle temperature variations are, therefore, not completely independent.

The steam temperature was varied with steam pressure for both reheat and nonreheat turbines. As the steam temperature increases, the steam turbine Rankine cycle efficiency increases. Figure 8.12 illustrates the increase in overall energy efficiency as the steam temperature increases.

The steam throttle temperature of 811°K (1000°F) was recommended for the preliminary optimum case. This decision was based on steam turbine and condenser-steam generator design considerations. Material and development problems are diminished at the lower temperature, as are component costs.

8.4.11 Effect of Steam Throttle Pressure

Variation of the steam throttle pressure was limited to one subcritical and one supercritical pressure. The values of pressure investigated were 16.547 and 24.132 MPa (2400 and 3500 psi) gauge. Figure 8.12 demonstrates the Rankine cycle principle that as pressure

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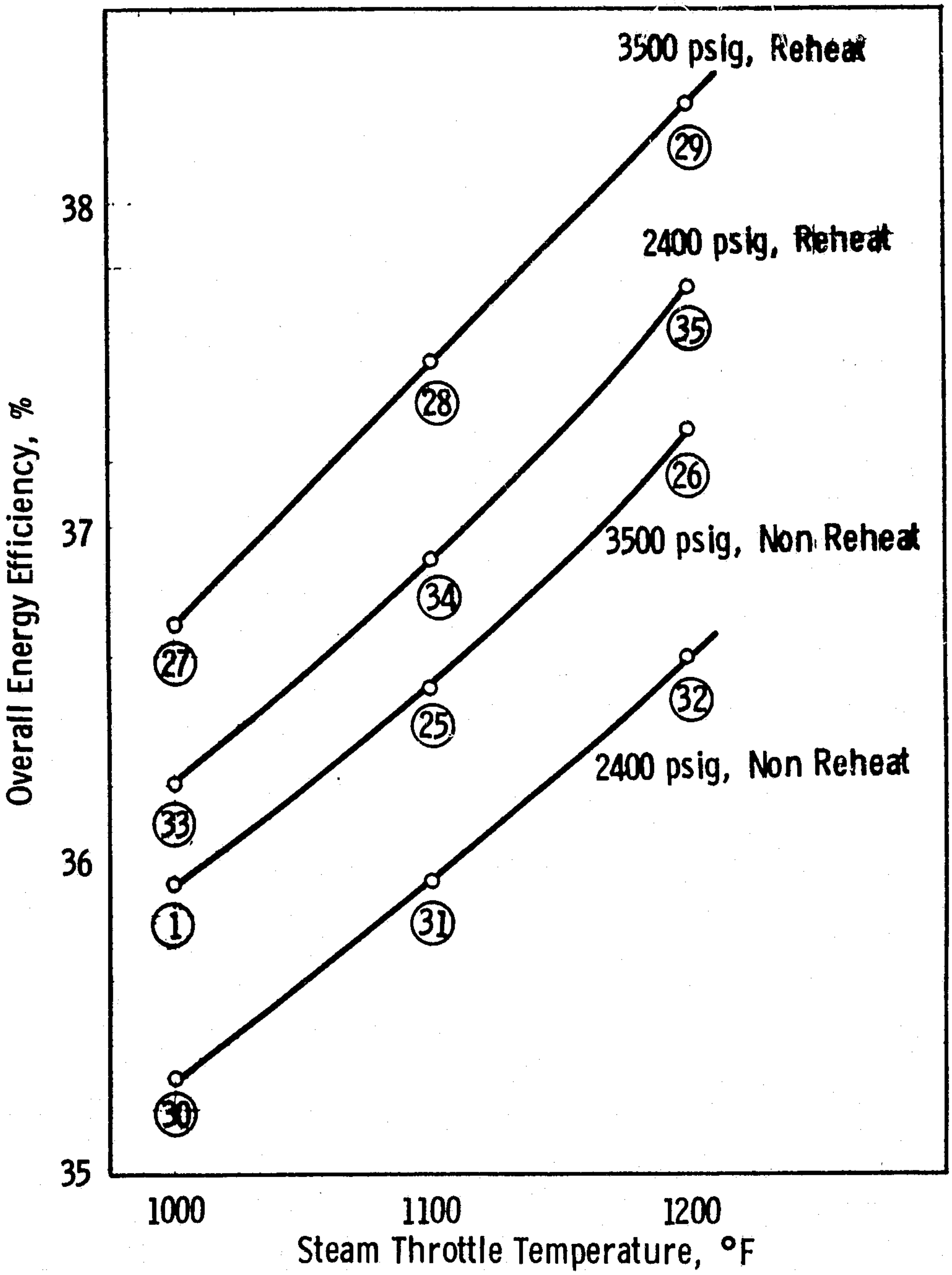

Fig. 8.12 — Effect steam throttle temperature on overall energy efficiency for a pressurized fluidized boiler plant

increases for a constant steam temperature, the steam turbine efficiency improves; and as steam turbine efficiency increases, the overall energy efficiency increases. In the nonreheat cases the overall efficiency increases better than 1.7% at a given steam temperature when the steam pressure increases from 16.547 to 24.132 MPa (2400 to 3500 psi) gauge. In the reheat cases, the improvement in overall energy efficiency is about 1.4%.

The 24.132 MPa (3500 psi) gauge throttle pressure was selected on the basis of efficiency. It was also selected because, at 24.132 MPa (3500 psi) gauge, DNB and all its uncertainties are avoided in the condenser-steam generator.

8.4.12 Effect of Nonreheat versus Reheat Steam Turbine

Referring to Figure 8.12 shows the effect on overall efficiency as a function of pressure and temperature of the steam. For a given steam temperature, the overall efficiency improvement of reheat versus nonreheat is approximately a constant 2.5%, regardless of the temperature. The reheat cycle was selected for incorporation in the preliminary optimum.

8.4.13 Effect of Working Fluid

The effect of cesium versus potassium as the working fluid in the liquid-metal subsystem was studied only for the preliminary optimum case. It was assumed that cesium would not be competitive with potassium. The calculation of the preliminary optimum plant, however, resulted in an overall energy efficiency of 42.9% for the cesium and 42.4% for the potassium.

The 1.2% efficiency advantage for cesium over potassium demonstrated that cesium is competitive with potassium. Final conclusions should not be made at this time due to the preliminary nature of the calculations and designs. Further effort is required, particularly in the turbine design.

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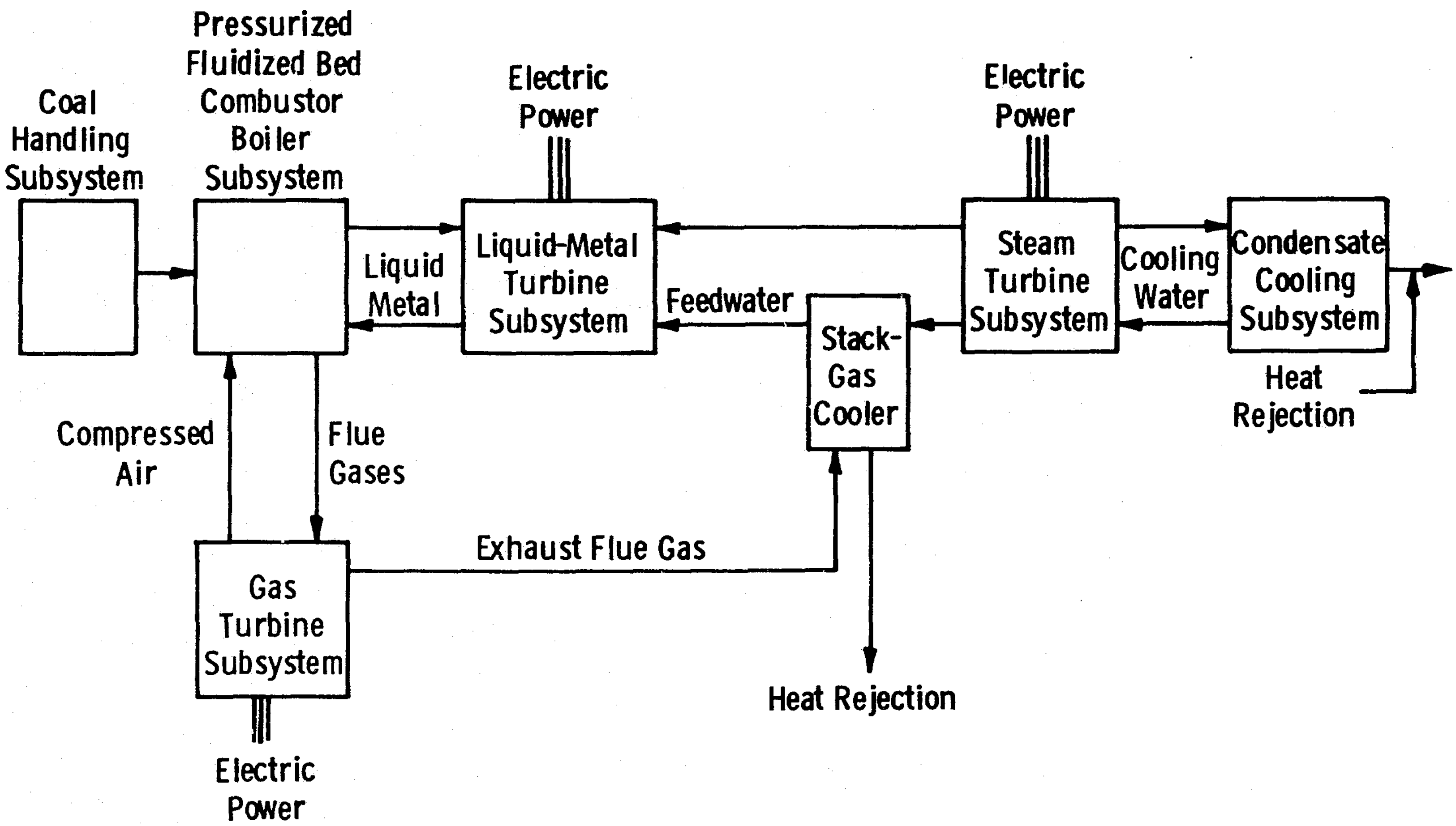

Fig. 8. 13—Flow sheet for a fluidized bed boiler plant

8.4.14 Effect of Power Level

No effort was made at this time to determine the effect on cycle performance for power variation. The efficiencies were assumed constant with power level to determine the effect of plant thermal rating on the cost of electricity.

8.5 Capital and Installation Costs of Plant Components

This section is divided into two segments: the first subsection presents the method of component sizing; the second outlines the method of component costing.

Component sizing and economic evaluation were performed by the various cognizant design groups for the metal vapor Rankine topping cycle subsystems. Flow schematics of the PFB and PF plant cycles are shown in Figures 8.13 and 8.14, respectively. The schematics show the cycle subsystems as labeled blocks.

The combustor pressurizing subsystem was sized and cost evaluated by the combustor-furnace and low-Btu gasifier design group (see Section 4). The combustor pressurizing subsystem consisted of coal handling and processing, compressor turbogenerator, the stack-gas cooler, the fluidized bed gasifier and boiler and related hot gas piping, and process air and steam piping. The steam turbine subsystem sizing and cost evaluation were performed by Westinghouse Large Turbine and Heat Transfer Divisions. The balance of plant was evaluated by Chas. T. Main, Inc. (see Section 2). The heat rejection subsystem was included in the assumptions of Section 2.

The method of sizing and costing plant components for the liquid-metal subsystem and its related subsystems, as shown in Figure 8.15, are presented in this section.

8.5.1 Method of Component Sizing

8.5.1.1 Pressurized Fluidized Bed

The sizing of the pressurized fluidized bed boiler, PFB, is covered in Section 4). The liquid-metal considerations in the design

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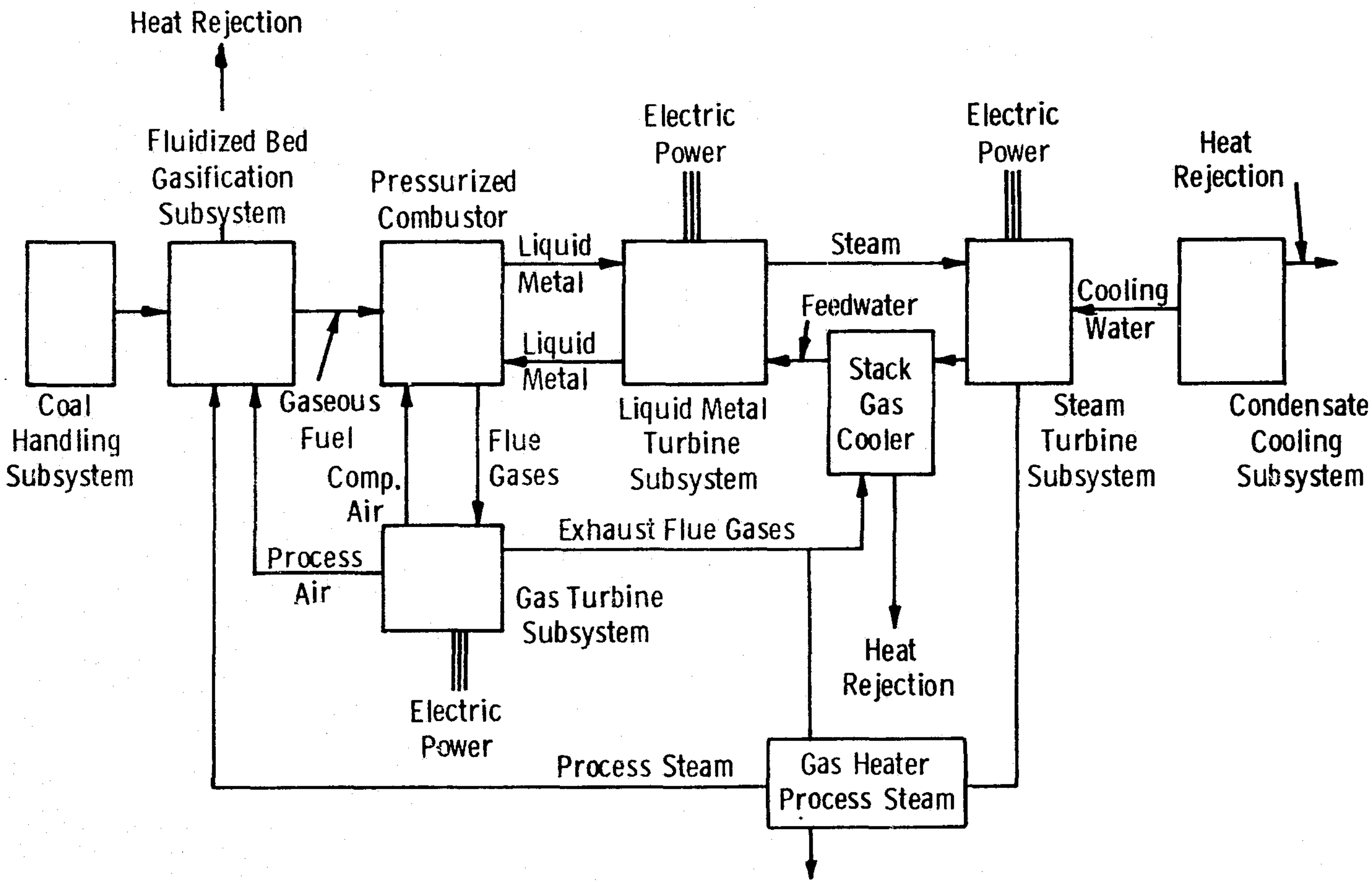


Fig. 8.14—Flow sheet for a pressurized furnace plant cycle

Dwg. 6352A76

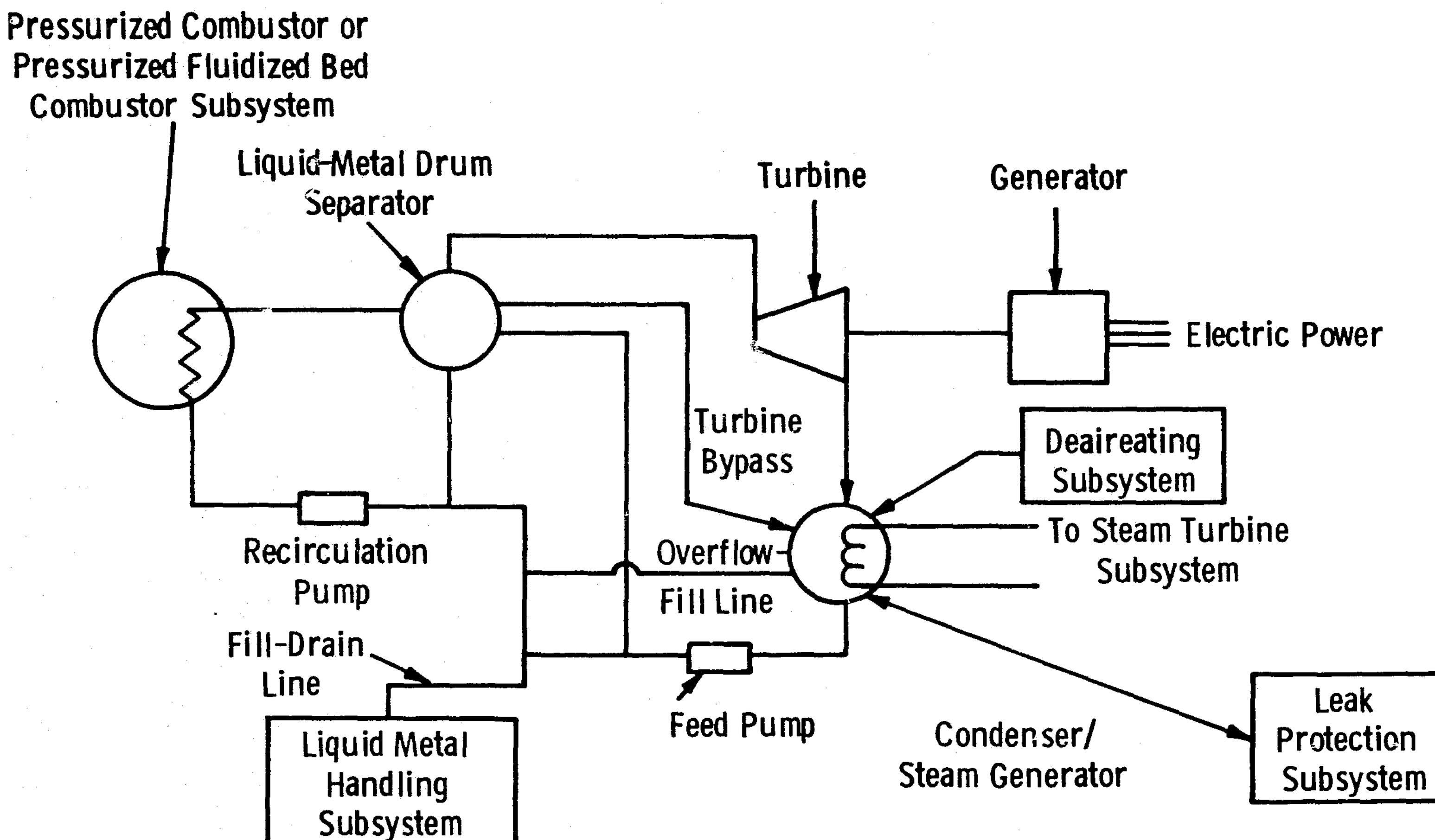


Fig. 8.15—Flow sheet for the liquid metal turbine subsystem

and sizing of the PFB were the heat required, Q_b, as determined in Subsection 8.3 by Equation 8.2. The overall heat transfer coefficient was assumed to be equivalent to the bed-side heat transfer coefficient [83.8 W/m^2-°K (50 Btu/hr-ft^2-°F)]. The tube-side liquid-metal pressure drop was assumed to be equal to that of the pressurized furnace, approximately 6% of the operating pressure. Finally, four PFB modules are assumed to be required for every 300 MWe of plant capacity.

8.5.1.2 Pressurized Furnace

The pressurized furnace, PF, design was an adaptation of the recirculating-type boiler proposed by A. P. Fraas (Reference 8.2). To ensure sufficient flow for a 2.5-to-1 circulation ratio, a centrifugal pump provides the driving force in an external recirculation loop which headers the subcooled liquid metal into the bottom of the furnace. The cold feed passes through the headers into tube bundle clusters and rises up through the combustion chamber to an upper set of headers. The two-phase mixture leaving the PF enters a liquid-metal vapor drum. The vapor is separated from the saturated liquid and passed to the liquid-metal turbine. The saturated liquid passes to a mixing header, where it mixes with the cold liquid-metal feed coming from the condenser-steam generator.

8.5.1.3 Liquid-Metal Vapor Drum

The liquid-metal vapor drum was sized on the assumption that under the worst transient surge the drum will never be more than two-thirds full of liquid, and that under normal conditions it is approximately half-filled with liquid. The Clinch River Breeder Reactor Plant (CRBRP) steam drum was sized on these criteria. The transient time of the saturated water in the CRBRP steam drum was calculated to be 60 s (1 min). It was then assumed that the worst transient surge in a liquid-metal topping cycle would not be as severe as in CRBRP, so the transit time for the liquid-metal drum was assumed to be half that of CRBRP, or 30 s (0.5 min). The volume of the drum, Vol_d, was then determined by:

$$Vol_d = \frac{2(RC - 1)\, W_{LM}\, t}{N_d\, \rho_\ell} \qquad (8.21)$$

where RC is the circulation ratio; W_{LM} is the total metal vapor mass flow rate to the turbine; N_d is the number of vapor drums; ρ_ℓ is the density of saturated liquid metal; and t is the transit time.

8.5.1.4 Liquid-Metal Vapor Turbine

The liquid-metal vapor turbine design was limited by available technology for large disk forgings of superalloys and refractory alloys. To compensate for the size limitations, the liquid-metal turbines are assumed to be modularized, double-flow units with built-up rotors. The rotors are similar to aircraft gas turbines, built up of disks and spacer rings rather than of a single-solid forging. The material candidates for the liquid-metal vapor turbine are discussed in Subsection 3.7, as are the bearing and shaft seal techniques.

The potassium turbine was designed (see Figure 8.16) as a 25 MWe, four-stage, double-flow, 1800 rpm turbine with a 1.83 m (6 ft) disk. Each generator is a four-pole, 1800 rpm machine rated at 30 MVA. The efficiencies assumed for the four stages of the potassium turbine were 82, 81, 79, and 75%, respectively. In the preliminary design the cesium turbine was assumed to have only two stages with similar power rating. Its efficiency was assumed to be 76%.

For the base case plant rating of 1200 MWe there are two liquid-metal turbines in tandem in each of the four liquid-metal loops, for a total of eight turbines. Since each turbine is double flow, the single condenser-steam generator in each loop would have four inlets.

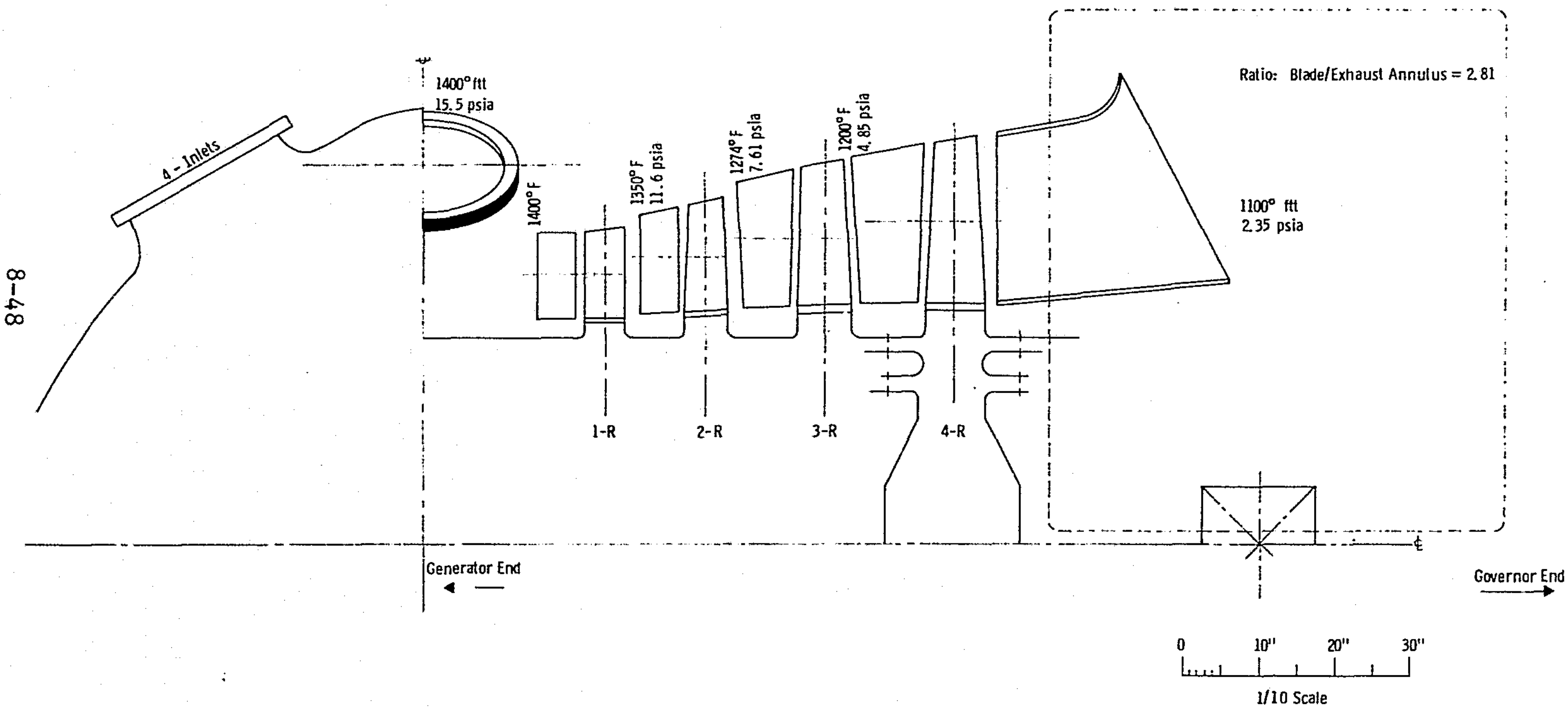
8.5.1.5 Metal Vapor Condenser-Steam Generator

Steam condensers for power plants are not designed in accordance with the ASME Unfired Pressure Vessel code. This is probably because the design pressure of such units is not over 105.4 kPa (15 psi). In the case of a potassium condenser, however, the hot potassium vapor is a lethal and flammable fluid, and liquid potassium reacts violently with water. For these reasons it is recommended that the potassium condenser vessel be designed in accordance with Section VIII (Unfired Pressure Vessels).

Dwg. 257C5n6

	1-C	1-R	2-C	2-R	3 C	3-R	4-C	4-R
Mean Dia, in	70.50		75.30		80.35		84.50	
Blade Exit, ht	11.45	11.50	14.00	14.88	17.90	19.00	21.00	21.75
Base Dia, in	59.05		61.30		62.45		66.50	
Gauging, %	25.0	36.2	30.0	42.9	32.0	44.8	38.0	52.8
Flow Area, in^2	690.8		992.0		1447.5		2194.5	
Min Reaction %	15.0		17.5		22.5		26.3	
Hub/Tip		0.72		0.67		0.62		0.60
Pitch, in								
Blades/Row								

Note: Major aerodynamic design constraint has been imposed by technical factors related to the procurement of acceptable rough disc forgings. Disc not to exceed 6 feet (maximum) diameter. Mtl. Spec. (TZM)



Double Flow
1800 RPM - 4 Pole
Nominal Rating - 25,000 kW/30,000 kVA MWe

Fig. 8.16—Longitudinal section of a potassium turbine

The design of power plant steam condensers is based upon the use of straight condenser tubing, the most economical form. The long straight tubes are supported at intervals by drilled plates. These large rectangular plates also serve as stays, or braces, for the flat condenser wall plates. Thus, the condensers are good for full vacuum but very little internal pressure. The slight differential expansion between the tubes and shell is taken up by the flexing of a flat steel membrane at one tubesheet.

In attempting to transpose such a design to a potassium vapor condenser operating at 811 to 978°K (1000 to 1300°F), generating high-pressure superheated steam within the tubes, many fundamental problems are encountered. The tubesheet thicknesses become prohibitive if conventional steam condenser tube spacing is used; if compact tube bundles are used, however, vapor velocities entering the tube bundle exceed sonic values.

To overcome these problems and at the same time allow for tube expansion, the condenser configuration shown in Figure 8.17 is recommended. The tube bundle is basically cylindrical, with the core of the cylinder large enough to avoid direct vapor impingement from the wet turbine exit vapor, moving at around 243.8 m/s (800 ft/s). Metal droplets at such velocities would most likely erode the tubes.

The tubes in the bundle are closely spaced radially, but are separated 11.43 to 15.24 cm (4-1/2 to 6 in) axially, 15.24 cm (6 in) for the lowest pressure [16.55 kPa (2.4 psi) abs] and 11.43 cm (4-1/2 in) for the higher pressures. For the 978°K (1300°F) designs the radial depth of the bundle has been increased because of the much greater driving head available on the potassium side.

The cylindrical tube bundle is surrounded by a spherical shell, which is recommended for two reasons: first, it is the only configuration which does not require stiffening rings in accordance with the ASME code. External stiffening rings are technically unacceptable because of excessive thermal stresses and consequent warping; and internal

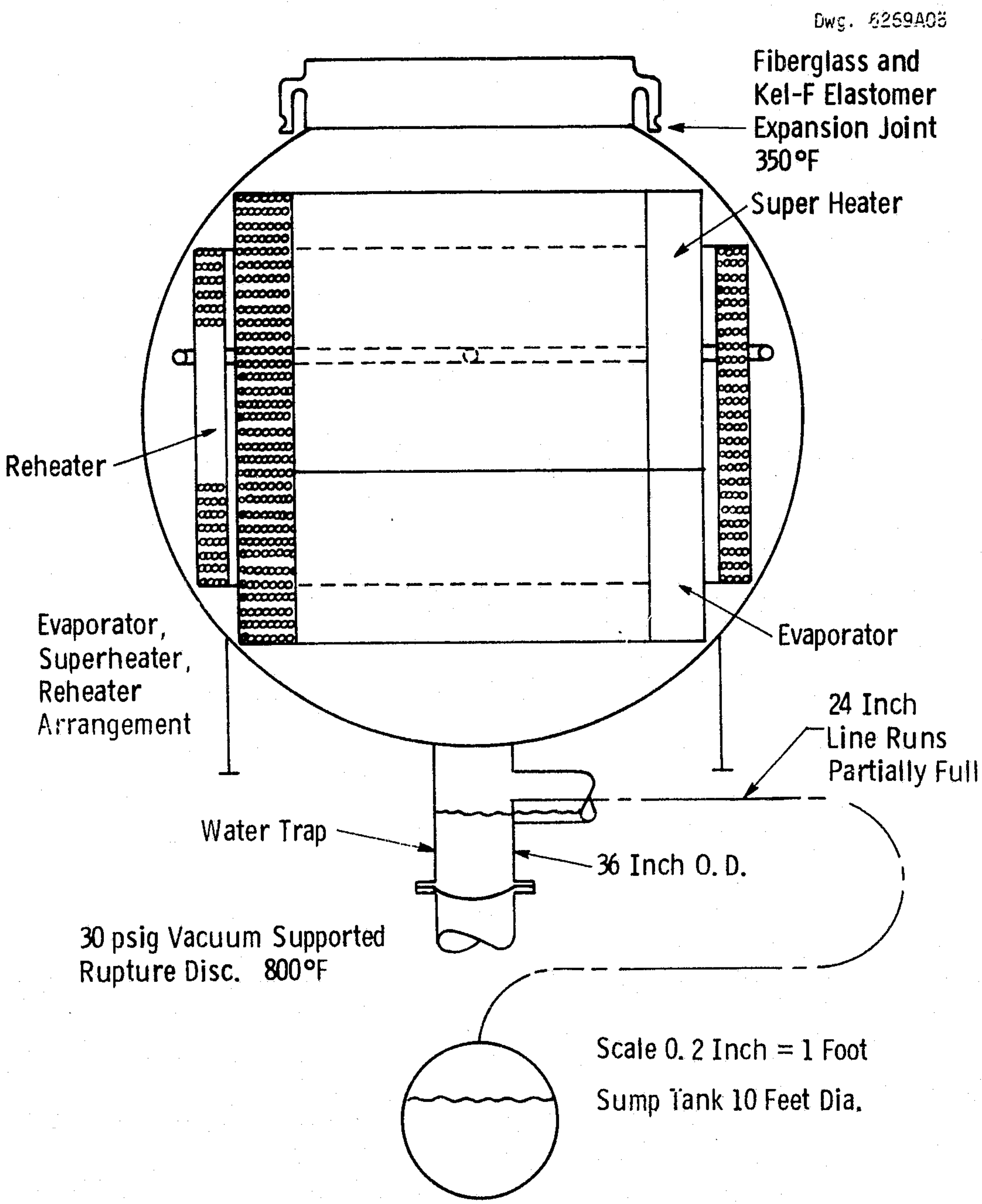


Fig. 8. 17 – Liquid metal condenser/steam generator

stiffening rings would interfere with drainage, complicate the bundle supports, and decrease usable volume. Second, a sphere is the most economical of material, being basically half the thickness of the corresponding cylinder. Another important reason for the use of a spherical shell is the large inherent reserve on allowable internal pressure. Thus, to meet full vacuum (as specified in the Code) the wall thickness required results in an allowable internal pressure of about 0.517 MPa (75 psi) gauge, which means that there is virtually no possibility of a condenser rupture due to a potassium-water reaction.

Since the condenser, as a pressure vessel, must be provided with pressure relief; since this pressure relief must be in the form of a vacuum-supported rupture disk; and since the rupture disk must operate below the creep temperature [700°K (800°F)], the rupture disk must be at the bottom of a liquid potassium pool. In the design shown in Figure 8.17 these conditions are met by providing a stagnant pool of potassium in the condenser drain line to act as an insulation layer. This pool also should act as a trap for water should a large water leak occur. The resulting potassium-water reaction will rupture the disk, but the bulk of the potassium will be retained in the hot-well storage tank.

The header-type tube bundles will be assembled externally to the shell, with all welding done on the outside. The completed tube bundle would be lowered into a hemisphere, a second hemisphere lowered into place, and the girth seam welded. Repairs to the bundle would be made by entering the condenser through a manway.

The steam generating tubing is designed in accordance with the procedures for Unfired Pressure Vessels, Section VIII, Part I, with the exception of the HA-188 tubing, which is not a Code-recognized material. The stress values used for the HA-188 tubing, however, are based upon the same criteria as are Code-allowable stress values (Reference 8.3).

Although the temperature gradient across the tube walls in some portions of the boiler-condenser was high, with consequent high thermal stresses, the practical effect of such conditions on the design will

Table 8.11 – Tube Bundle Design Summary

Case No.	Number of Tubes			Heat Transfer Area		Sphere Diameter, ft	Tubes, Steam Generator			Tubes, Reheater		
	Evaporator	Superheater	Reheater	Steam Generator	Reheater		ID	OD	Material	ID	OD	Material
1	386	642		10,600		27.2	0.625	0.858	800 H			
2	372	619		10,230		26.8	0.625	0.858	800 H			
3	360	600		9,890		26.3	0.625	0.858	800 H			
4	383	638		10,530		27.2	0.625	0.858	800 H			
5	383	639		10,560		27.2	0.625	0.858	800 H			
6	384	640		10,580		27.2	0.625	0.858	800 H			
7	390	650		10,730		27.4	0.625	0.858	800 H			
8	390	650		10,730		27.4	0.625	0.858	800 H			
9	386	643		10,610		27.3	0.625	0.858	800 H			
10	386	643		10,610		27.3	0.625	0.858	800 H			
11	386	643		10,600		27.2	0.625	0.858	800 H			
12	383	638		10,530		27.1	0.625	0.858	800 H			
13	390	650		10,730		27.4	0.625	0.858	800 H			
14	374	623		10,292		26.8	0.625	0.858	800 H			
15	365	608		10,040		26.5	0.625	0.858	800 H			
16	363	605		9,985		26.4	0.625	0.858	800 H			
17	379	632		10,434		26.7	0.625	0.858	800 H			
18	377	628		10,374		26.7	0.625	0.858	800 H			
19	302	503		8,315		24.1	0.625	0.858	800 H			
20	179	298		4,926		18.6	0.625	0.858	800 H			
21	412	687		11,320		28.1	0.625	0.858	800 H			
22	399	665		10,970		27.7	0.625	0.858	800 H			
23	385	642		10,570		27.2	0.625	0.858	800 H			
24	384	639		10,544		27.1	0.625	0.858	800 H			
25	388	658		13,085		24.0	0.625	1.06	800 H			
26	317	529		10,507		21.0	0.625	0.963	HA-188			
27	325	475	200	8,248	5,580	26.7	0.625	0.858	800 H	1.5	1.75	800 H
28	375	625	200	10,114	5,600	25.8	0.53	0.750	800 H	1.5	1.75	800 H
29	250	420	200	8,301	6,445	25.0	0.625	0.963	HA-188	1.5	1.75	800 H
30	360	600		8,473		24.5	0.625	0.788	800 H			
31	331	551		9,714		21.0	0.625	0.911	800 H			
32	300	500		7,786		20.2	0.625	0.856	HA-188			
33	300	500	200	8,200	5,948	26.7	0.625	0.788	800 H	1.5	1.75	800 H
34	276	460	200	8,070	5,650	24.1	0.625	0.911	800 H	1.5	1.75	800 H
35	248	414	200	6,452	6,555	22.6	0.625	0.856	HA-188	1.5	1.75	800 H
36	355	592		9,770		26.1	0.625	0.788	800 H			
37	375	625		10,310		26.8	0.625	0.788	800 H			
38	379	632		10,430		26.7	0.625	0.858	800 H			
39	402	670		11,040		27.8	0.625	0.858	800 H			

depend upon the number of such temperature cycles, since thermal stresses are considered to be transient. Such transient conditions must be considered in a subsequent study phase.

In calculating the heat transfer, the mass velocity and inside diameter of the tubes were held constant, not only to simplify the calculations but also to minimize random variations in results. Also, for the 866°K (1100°F) vapor-condensing temperature, sphere size was considered to vary as the square root of surface, rather than as the cube root. In other words, the radial thickness of the tube bundle was held constant. This was done to hold condensing vapor pressure drop to a constant value. For the higher condensing pressures and temperatures, a more compact bundle was assumed, but space was allowed so that all welding could be done from outside the bundle. See Table 8.11 for the tube bundle design summary.

Tubing costs were based on communications with International Nickel Co., Huntington, West Virginia, for Incoloy 800 H; and Stellite Division at Kokomo, Indiana, for HA-188. Tubing costs are probably somewhat low, however, as costs were not quoted to a definite specification. Even if tubing costs were doubled, though, the overall cost of the boiler-condenser would not be greatly affected, as tubing material was rarely more than 10% of the calculated overall condenser cost.

The basic heat transfer tube material chosen was Incoloy 800 H, because it is resistant to chloride and caustic stress-corrosion cracking. For temperatures over 922°K (1200°F), however, the strength of Incoloy 800 H falls to such a low value that HA-188 material is more economical for the high-pressure applications.

For the reheaters, where the pressure is low, Incoloy 800 H can be used for all cases. While Croloy might be considered for reheater tubing, it is very doubtful that a transition weld could be fabricated that would withstand the temperature cycles, and the steam-side corrosion rate would be excessive.

For the spherical shell, Type 316 SS material is the most economical, as it results in a greater than 10% wall-thickness saving as compared to Type 304, thus negating the cost advantage of Type 304. Incoloy 800 H must be used for the spherical shell, however, as it is the only material acceptable for external pressure at design temperature [978°K (1300°F)] under the ASME Pressure Vessel Code.

8.5.1.6 Liquid-Metal Condenser Hot Well

Ordinarily, the hot wells were assumed to be within the condenser shell. For the purpose of mitigating liquid metal/water reaction the liquid-metal condenser hot well was placed outside the condenser shell, as shown in Figure 8.17. This separation minimizes the possibility of the bulk of the saturated liquid metal coming into direct contact with water in the event of a steam-tube leak or rupture, and mitigates the potential severity of the liquid metal/water reaction. It reduces the possible damage due to the liquid-metal reaction, reduces the amount of liquid-metal inventory which must be dumped, and shortens cleanup and recommissioning time.

The hot well was sized to hold a minute's worth of liquid metal at $\sim$ 60% of the capacity available (see Equation 8.21). This excess volume allows for thermal expansion of the liquid metal and eliminates the need for expansion tanks in the liquid-metal loop.

8.5.1.7 Liquid-Metal Dump Tank

The four liquid-metal dump tanks were sized to accommodate the reaction products of a liquid metal/water reaction in the condenser-steam generator. This accident was assumed to produce the worst pressure surge and largest quantity of reaction products to the dump tank. Each dump tank hold-up volume was evaluated for a minute of normal hot-well mass flow of saturated liquid at the rupture disk design pressure of 0.207 MPa (30 psi) gauge.

As mentioned in Subsection 8.5.1.6, the liquid-metal hot well has been removed from the condenser shell to reduce the surface area of liquid metal in the event of a steam-tube rupture. The design of the condenser drain line in Figure 8.17 shows the stagnant pool of liquid metal above the rupture disk in the condenser dump line and the smaller drain line to the hot well which runs off the dump line at a right angle. In the event of a large tube leak or tube rupture, the water will collect in the stagnant pool, and the pressure rise due to the liquid metal/ water reaction will rupture the disk. The reaction products will flow to the dump tank. The bulk of the liquid metal is relatively uncontaminated while it is drained to the storage tank where it is processed to remove any impurities.

Each dump tank liquid hold-up is 70% of its capacity. A small fraction of the capacity is filled with a matrix of metal rods which acts as a condensing surface for the entering vapor. The remaining capacity, ~ 30%, is for expansion.

The dump tank is equipped with a vent line to blow off the hydrogen produced by the reaction. A scrubber to remove liquid-metal/water reaction products and a flame suppressor will be provided in the vent line.

8.5.1.8 Liquid-Metal Pumps

The liquid-metal feed or condensate pump in each of the four loops was assumed to be a free surface centrifugal type, similar to the intermediate system pumps of the Fast Flux Test Facility (FFTF) and CRBRP. The pump operates at the temperature of the liquid-metal condensate. The pump head was calculated equivalent to the sum of the frictional losses in the vapor and feed piping, the turbine pressure loss, and the static head due to the hot well to mixing header elevational difference [10.1 m (~ 30 ft)].

In the once-through liquid-metal subsystem design the feed pump head had the additional requirement of making up the single- and two-phase total pressure losses of the liquid-metal vapor generator.

In the recirculation liquid-metal subsystem design, recirculation pumps were assumed to make certain that sufficient head was available to provide a 2.5-to-1 circulation ratio in each of the four loops. The circulation pumps operate at the temperature resulting from the mixture of one and one-half parts saturated liquid from the liquid-metal vapor drum, which is 167°K (300°F) hotter than the one-part condensate liquid. For conservatism the entire vapor generator pressure drop was assumed to be in the two-phase region. Additional conservatism was added by neglecting static heads. The circulation pump head was calculated as the sum of the frictional loss from the mixing header to the boiler inlet, and the two-phase friction (Reference 8.4) and momentum losses of the boiler and exhaust piping to the vapor drum.

Table 8.12 lists the ranges of pump capacities and total developed heads calculated for the various system configurations, operating parameters, and working fluids. The frictional and momentum pressure losses of the pressurized fluidized bed vapor generator was assumed equal to those of the pressurized furnace.

Table 8.12 - Range of Pump Performance Characteristics

Pump	Working Fluid	Capacities, gpm	Total Developed Head, ft	Pump Power kWe/Pump
Feed Pump	K	4,400 to 5,600	70 to 170	50 to 150
	Cs	7,400	80	200
Recirc. Pump	K	11,000 to 14,500	12 to 21	25 to 50
	Cs	19,000	9	60

8.5.1.9 Liquid-Metal Piping

The liquid-metal piping was assumed to be welded pipe conforming to Section VIII of the ASME Pressure Vessel Code. Piping material selection was based on the recommendation of Subsection 3.7 of this report (see Table 3.39), with the exception that 316 SS was used for all cold-leg piping.

The cold-leg liquid piping was sized on the basis of a 7.62 m/s (25 ft/s) flow velocity, for both feed and recirculation piping. The two-phase piping from the furnace to the drum was based on a flow velocity of less than 3.05 m/s (10 ft/s), and the vapor piping at 182.9 m/s (600 ft/s) flow velocity. Smooth pipe friction factors were assumed.

Table 8.13 shows the various sizes and lengths assumed for the liquid-metal piping.

Table 8.13 - Liquid-Metal Loop Piping Dimensions[a]

	Outside Diameter, in	Number per Plant	Total Length, ft
Feed Piping	9 (12)[b]	4	800
Recirc. Piping	10 (14)[b]	8	500
Two-Phase Piping	30	16	400
Vapor Piping	72	8	1600

[a]Wall thickness with operating conditions and material according to Section VIII Unfired Pressure Vessel.

[b]Cesium.

8.5.1.10 Liquid-Metal Storage Tanks

The liquid-metal storage tanks in each loop were sized to hold the entire liquid-metal inventory plus 20% at the liquid-metal turbine inlet temperature. The outside diameter and length were limited to 3.65 and 10.67 m (12 and 35 ft), respectively, to allow for shipment by normal routing and placement below the condenser-steam generator hot-well tank.

Four separate tanks were employed to allow for the appropriate sizing of each tank and to reduce the quantity of potassium in each container, thus diminishing the risk of a major spill or leak.

The tanks also act as dump tanks in the event of a sudden increase in oxygen level. The system purity is continuously monitored by oxygen meters. In the event of a liquid metal/water reaction in the condenser and rupture of the rupture disk described in Subsections 8.5.1.6 and 8.5.1.7, the condenser exhausts to the dump tank while the rest of the loop components drain to the storage tank. This minimizes the contamination of the bulk of the loop liquid metal and permits leak tests to determine the location and extent of damage. The system is designed to drain by gravity to the storage tank. Separate lines from the major loop components are sized to gravity drain in a minimum of time. These lines and their valving will be designed to eliminate failure due to thermal shock. The tanks will be maintained at some intermediate temperature to avoid thermal shock damage by a continuous bleed-and-feed line. This bleed-and-feed line will be plumbed to a hot trap to purify the liquid metal in the event of an emergency dump.

Since the tank must be located at the lowest elevation in the system, a lined concrete pit was selected.

8.5.1.11 Liquid-Metal Inventory

The liquid-metal inventory was determined as the sum of the liquid-metal hold-up of the furnace-boiler, the vapor drum, the vapor ducting, the hot-well tank, the liquid feed piping, and recirculation piping. For conservatism 20% was added to account for liquid metal in the vapor turbines, the condenser-steam generator, the impurity monitoring system, and the receiving and processing system.

Table 8.14 represents the inventories calculated for the two liquid metals considered and for once-through and recirculating liquid-metal systems. Adjustments were made for the liquid-metal inventory requirements of other cases. The inventories were corrected by the ratio of the liquid-metal flow rate of the case being considered to the liquid-metal flow rate of the appropriate reference case. The flow ratio correction was applied only to that 64% of the total inventory which is flow-rate dependent (drum and hot-well hold-up volumes).

Table 8.14 - Liquid-Metal Inventories, lb

	Potassium		Cesium	
	Recirc.	Once-through	Recirc.	Once-through
PF and PFB	80,000	80,000	176,500	176,500
Main Piping	15,500	15,500	51,000	51,000
Recirc. Piping	24,300	---	65,900	---
Drum	90,000	---	476,500	---
Hot Well	120,000	122,000	381,200	381,200
	329,800	217,500	1,151,100	608,700
Miscellaneous (20%)	66,000	43,500	230,200	121,700
Total Inventory	395,800	261,000	1,381,300	730,400

8.5.1.12 Plant Arrangement and Component Modularization

As discussed in Subsection 8.5.1.10, the liquid-metal storage tanks were modularized for ease of placement, shipment, and reduction of liquid-metal volume in the event of a leak or spill. This is true of all the liquid-metal tanks and drums. The liquid-metal turbines were modularized to compensate for the current technological inability to forge large disks of superalloys and refractory alloys.

The number of modules of the various components and the plant arrangement were selected to allow for partial plant operation. By proper component sizing, arrangement, and plumbing, a loop consisting of a combustor pressurizing subsystem and a liquid-metal subsystem can operate totally independently of other such loops to provide steam to a single steam turbine subsystem. Such an arrangement provides the flexibility for partial plant operation, which significantly increases the plant availability.

Table 8.15 - Pressurized Fluidized Bed Cost Data

Point No.	Parameter Variation	Airflow, lb/s	AFR $(W_i/W_R)^{0.8}$	Reference Case	Cost x 10^{-3}, $	Units Required
1	Base Case 1	716	1.00	1	23.277	4
2	Subbituminous	722	1.00	2	20.875	4
3	Lignite	741	1.00	3	22.412	4
7	ε = 0.7	710	0.993	1	23.3	4
8	ε = 0.8	710	0.993	1	24.3	4
11	RC = 1:1	716	1.00	1	23.3	4
13	GFWHTR	596	0.863	1	20.1	4
15	GAS ECON	645	0.920	1	21.4	4
17	PR = 5	810	1.00	17	32.202	4
18	PR = 10	740	1.00	18	24.998	4
19	ϕ = 2.0	641	1.00	19	12.413	8
20	ϕ = 3.0	712	1.00	20	11.153	12
21	TG = 1600°F	680	0.988	22	23.653	4
22	TG = 1700°F	690	1.00	22	24.352	4
23	TK = 1500°F/1200°F	716	1.00	23	23.882	4
24	TK = 1600°F/1300°F	710	1.00	24	28.236	4
25	3500 psig/1100°F	700	0.982	23	23.454	4
26	3500 psig/1200°F	690	0.977	24	27.6	4
27	3500/1000/1000*	700	0.982	1	22.9	4
28	3500/1100/1100*	690	0.971	23	23.2	4
29	3500/1200/1200*	673	0.958	24	27.1	4
30	2400 psig/1000°F	722	1.007	1	23.46	4
31	2400 psig/1100°F	716	1.00	23	23.9	4
32	2400 psig/1200°F	700	0.989	24	27.9	4
33	2400/1000/1000*	710	0.993	1	23.72	4
34	2400/1100/1100*	700	0.982	23	23.46	4
35	2400/1200/1200*	680	0.966	24	27.3	4
36	2400/2 in Hg abs	716	1.00	1	23.3	4
37	2400/9 in Hg abs	756	1.044	1	24.335	4
38	3500/2 in Hg abs	700	0.982	1	22.9	4
39	3500/9 in Hg abs	740	1.027	1	23.9	4
40	600 MWe	566	1.00	49	23.653	2
41	900 MWe	566	1.00	49	23.653	3
42	1500 MWe	566	1.00	49	23.653	5
46	Cs, 1200 MWe	582	1.00	46	23.68	4
47	Cs, 600 MWe	582	1.00	46	23.68	2
48	Cs, 1500 MWe	582	1.00	46	23.68	5
49	1200 MWe	566	1.00	49	23.653	4

*psig/°F/°F

For this study four loops were selected as the basis of component sizing and arrangement.

8.5.2 Method of Component Cost Evaluation

8.5.2.1 Pressurized Fluidized Bed

The cost evaluation of the pressurized fluidized bed (PFB) is covered in Section 4. For the liquid-metal vapor Rankine topping cycle study twelve PFB cases were sized and costed on the basis of the heat load required by the liquid metal, the gas turbine inlet temperature, the gas turbine compression ratio, and the air equivalence ratio. Among the twelve cases were the costs of the PFB for the three different fuels (Points 1, 2, and 3), the variations in compressor pressure ratio (Points 17 and 18), the air equivalence ratio (Points 19 and 20), gas turbine inlet temperature (Point 22), liquid-metal temperatures (Points 23 and 24), and the preliminary optimum plants with potassium (Point 49) and cesium (Point 46) as the working fluid. For cases where the above variables were similar, the cost of the PFB was determined by:

$$\$' = (AFR)(\$) \tag{8.22}$$

where

$$AFR = (W_a'/W_a)^{0.8} \tag{8.23}$$

where $\$'$ = cost of new PFB

$\$$ = cost of reference PFB

W_a = compressor airflow rate of reference PFB (lb/s)

W_a' = compressor airflow rate of new PFB (lb/s).

Table 8.15 lists the point number, the compressor airflow, the AFR installed costs per unit PFB, and the number of units per plant. There are four PFB modules per unit. The cost of materials and the cost of installation per unit was determined to be 64 and 36%, respectively, of the installed cost per unit.

8.5.2.2 Pressurized Furnace

The pressurized furnace (PF) (Base Case 2, Point 4) was adapted from the design proposal of A. P. Fraas in 1973. The thermal duty per furnace of Base Case 2 is 20% higher than the Fraas proposal. The header drums, downcomer pipes, and vapor separator incorporated inside the Fraas furnace are external to the Base Case 2 PF design. Thus, the total furnace and boiler weight of the Fraas design was considered conservative for the Base Case 2 PF total weight.

The material cost of the Base Case 2 PF was determined by applying a \$22.05/kg (\$10/lb) cost of material. This figure is comparable to the installed cost of fossil-fired boilers. To be conservative, an additional 20% was included to the Base Case 2 PF as installation because of the liquid-metal environment. It is assumed that this estimate is accurate within 25%.

For the other PF cases calculated, the cost of material and cost of installation were corrected according to the ratio of unit thermal ratings as in Equation 8.22. The thermal rating ratio (TRR) replaced AFR in Equation 8.23 and is defined as:

$$TRR = (Q_i/Q_R)^{0.8} \qquad (8.24)$$

where Q_i is the unit thermal rating in Btu/hr and Q_R is the reference unit thermal rating.

Table 8.16 lists the costs of materials and installation per furnace, the point number, the furnace thermal rating ratio, and the total number of furnaces.

Table 8.16 - Pressurized Furnace Costing Data[a]

Point No.	Parameter Variation	Unit Thermal Rating x 10^{-9}, Btu/hr	TRR $(Q_i/Q_4)^{0.8}$	Material Cost x 10^{-3}, $	Install Cost x 10^3, $	Number Units
4	Base Case 2	0.819	1.00	2200	450	8
5	Subbituminous	0.820	1.00	2200	450	8
6	Lignite	0.822	1.00	2200	450	8
9	$\varepsilon = 0.7$	0.827	1.00	2200	450	8
10	$\varepsilon = 0.8$	0.827	1.00	2200	450	8
12	RC = 1:1	0.819	1.00	2200	450	8
14	GFWHTR	0.676	0.858	1900	390	8
16	Gas Economizer	0.740	0.922	2000	415	8
43	600 MWe	0.756	0.938	2100	420	4
44	900 MWe	0.756	0.938	2100	420	6
45	1500 MWe	0.756	0.938	2100	420	10
50	1200 MWe	0.756	0.938	2100	420	8

[a]Reference Costs: Material $2,200,000
Installation $450,000.

8.5.2.3 Combustor Pressurizing Subsystem

The combustor pressurizing subsystem cost evaluation is detailed in Section 4. This includes recuperators, gas-heated economizers, and feedwater heaters, hot gas piping and the pressurizing gas turbine generators which were cost evaluated by the combustor-furnace, and low-Btu gasifier design groups for a pressurizing gas turbine generator air inlet

Table 8.17 - Combustor Pressurizing Subsystem Costs

Point No.	$(W_a/650)^{0.8}$	Recuperator Cost x 10^{-6}, $ Reference/Actual		Stack-Gas Cooler Cost x 10^{-6}, $ Reference/Actual		Hot Gas Piping x 10^{-6}, $ Reference/Actual		Pressurizing Gas Turbine Generator x 10^{-6}, $ Reference/Actual	
1	1.08					2.0	2.2	6.7	7.2
2	1.088					2.0	2.0	6.7	7.29
3	1.11					2.0	2.2	6.7	7.44
4	1.061					2.0	2.0	6.7	7.1
5	1.049					2.0	2.0	6.7	7.03
6	1.0367					2.0	2.0	6.7	6.95
7	1.073	1.9	2.0			2.0	2.1	6.7	7.2
8	1.073	3.2	3.4			2.0	2.1	6.7	7.2
9	1.049	2.5	2.6			2.0	2.0	6.7	7.03
10	1.049	4.3	4.5			2.0	2.0	6.7	7.03
11	1.08					2.0	2.2	6.7	7.2
12	1.06					2.0	2.1	6.7	7.1
13	0.933			1.7	1.6	2.0	1.9	6.7	6.2
14	0.91			1.7	1.54	2.0	1.8	6.7	6.1
15	0.994			1.7	1.7	2.0	2.0	6.7	6.7
16	0.975			1.7	1.66	2.0	1.9	6.7	6.6
17	1.19							5.7	6.8
18	1.11							5.9	6.5
19	0.994							6.7	6.6
20	1.073							6.7	7.2
21	1.0367					1.8	1.86	6.5	6.7
22	1.049					1.9	2.0	6.6	6.9
23	1.080					2.0	2.2	6.7	7.2
24	1.073					2.0	2.1	6.7	7.2
25	1.061					2.0	2.0	6.7	7.1
26	1.049					2.0	2.0	6.7	7.03
27	1.061					2.0	2.0	6.7	7.1
28	1.049					2.0	2.0	6.7	7.03
29	1.0367					2.0	2.0	6.7	6.9
30	1.088					2.0	2.2	6.7	7.3
31	1.08					2.0	2.2	6.7	7.2
32	1.061					2.0	2.1	6.7	7.1
33	1.073					2.0	2.1	6.7	7.2
34	1.061					2.0	2.1	6.7	7.1
35	1.0367					2.0	2.0	6.7	6.95
36	1.08					2.0	2.2	6.7	7.2
37	1.128					2.0	2.2	6.7	7.5
38	1.061					2.0	2.1	6.7	7.1
39	1.11					2.0	2.2	6.7	7.4
40	0.925			1.5	1.390	1.6	1.6	6.5	6.0
41	0.925			1.5	1.390	1.8	1.6	6.5	6.0
42	0.925			1.5	1.390	1.8	1.6	6.5	6.0
43	0.895			1.5	1.340	1.8	1.6	6.5	5.8
44	0.895			1.5	1.340	1.8	1.6	6.5	5.8
45	0.895			1.5	1.340	1.8	1.6	6.5	5.8
46	0.915			1.5	1.37	1.8	1.6	6.5	5.9
47	0.915			1.5	1.37	1.8	1.6	6.5	5.9
48	0.915			1.5	1.37	1.8	1.6	6.5	5.9
49	0.925			1.5	1.490	1.8	1.6	6.5	6.0
50	0.895			1.5	1.340	1.8	1.6	6.5	5.8

flow rating of 294.8 kg/s (650 lb/s). These costs were corrected by Equation 8.22 with Equation 8.23 replaced by:

$$AFR = (W_a/650)^{0.8} \qquad (8.25)$$

Table 8.17 lists appropriate point number, the AFR, the unit costs of the individual component, and number required. The recuperator material and installation costs are 75 and 25%, respectively, of the total unit costs given in Table 8.17. The same is true of the gas-heated economizers and feedwater heaters. The total installed cost of the hot gas piping is listed. The gas turbine installation cost is assumed constant.

8.5.2.4 Liquid-Metal Subsystem Tanks

The liquid-metal subsystem tanks and vapor drum were cost evaluated on the basis of stainless steel, ASME Class 1, nonreactor development technology standards. The vessel cost was \$33.07/kg (\$15/lb) per vessel. Insulation cost was \$430.60/m^2 (\$40/ft^2). Both these installed costs are adapted from CRBRP costs and include 10% for installation. For conservatism, the unit cost of material and insulation was assumed to be 90% and installation 10% of the total installed costs. Table 8.18 illustrates the various tanks sized and costed for a total plant potassium flow rate of 0.9072 Mg/s (7 2 x 10^6 lb/hr). The costs evaluated for the liquid-metal vapor drums are believed accurate to 10%; and the costs of the other liquid-metal tanks are believed to be conservatively high (approximately 30%).

8.5.2.5 Liquid-Metal Vapor Turbine

The potassium turbine generators were costed from a Westinghouse Steam Turbine Division catalog price listing for 25,000 kW rating. To compensate for the use of superalloys and refractory alloys the catalog price was approximately doubled for a \$3 million material cost. The cesium turbine, which was designed with only two stages instead of the four stages in the potassium turbine, was assumed to cost two-thirds as

Table 8.18 - Typical Liquid-Metal Subsystem Tank Cost Data

Item	Size Diameter x Length, ft	Cost/Vessel x 10^{-3}, \$	Insulation x 10^{-3}, \$	Installed Cost x 10^{-3}, \$	Quantity	Total Installed Cost x 10^{-3}, \$
Potassium Storage Tank	10 x 30	1,181	38	1,219	4	4,876
Potassium Hot-well Tank	8 x 25	787	26	813	4	3,252
Potassium Dump Tank	8 x 20	630	21	651	4	2,604
Potassium Drum	8 x 22	693	23	716	4	2,864

much as the potassium turbine, or $2 million. For both turbines the cost of installation was 9% of the material cost.

The accuracy of the liquid-metal turbine cost evaluation is difficult, at best, to estimate. Even a ± 50% accuracy would represent approximately a 2% variation in the overall plant cost. If the cost errors were higher than 50%, the integrated system would need to be reoptimized.

The obvious conclusion is that the design, manufacture, and cost evaluation of liquid-metal vapor turbines requires greater depth and effort.

8.5.2.6 Liquid-Metal Condenser-Steam Generator

The method of cost evaluation of the liquid-metal condenser-steam generator is illustrated on Table 8.19 for Base Case 1. Table 8.20 lists the cost summary for Points 1 through 39. The remaining Points (40 through 50) are comparable to Point 27 in Table 8.20. The cost of material was assumed to be 70% of the total cost listed in Table 8.20, and the installation cost 30% of the total cost.

Table 8.19 - Point 1 Boiler Condenser Cost

Item	Material, $	Labor, $
Spherical Housing	106,000	233,000
Insulation	(Included above)	94,000
Steam Gen. Tubing	149,000	---
Steam Gen. Headers		
Inlet	2,000	---
Outlet	160,000	---
Crossover	118,000	---
Tube Supports	170,000	---
Fabrication and Tests		1,285,000
Totals	705,000	1,612,000
Total Cost, per Condenser		$2,317,000

Table 8.20 - Cost Summary of Liquid-Metal Condenser Steam Generator

Point No.	Sphere Material, Labor, and Insulation x 10^{-3}, $	Main Headers and Miscellaneous (Varies with Surface) x 10^{-3}, $	Fabrication and Test (Varies with Surface) x 10^{-3}, $	Heat Transfer Tubing x 10^{-3}, $	1 Condenser Total Cost x 10^{-3}, $
1	471	412	1,285	148	2,317
2	459	398	1,243	144	2,244
3	440	384	1,200	139	2,163
4	471	409	1,280	148	2,308
5	471	410	1,282	148	2,311
6	471	411	1,283	149	2,314
7	479	417	1,303	151	2,350
8	479	417	1,303	151	2,350
9	475	412	1,290	149	2,326
10	475	412	1,290	149	2,326
11	471	412	1,289	149	2,325
12	469	409	1,280	148	2,306
13	---	---	---	---	---
14	459	400	1,250	145	2,254
15	448	390	1,220	141	2,199
16	445	388	1,211	140	2,184
17	455	406	1,266	146	2,273
18	455	403	1,260	146	2,267
19	329	323	1,010	117	1,779
20	172	191	598	69	1,030
21	561	440	1,375	159	2,535
22	500	426	1,330	154	2,410
23	472	410	1,283	148	2,313
24	470	409	1,280	148	2,307
25	326	509	1,586	315	2,736
26	219	408	1,276	667	2,570
27	455	20 536	1,675	116 87	2,889
28	423	20 610	1,910	139 88	3,190
29	431	20 571	1,790	527 101	3,440
30	381	329	1,030	86	1,826
31	219	377	1,179	163	1,938
32	253	20 302	945	354	1,874
33	455	20 548	1,725	84 93	2,925
34	331	20 523	1,664	136 88	2,762
35	353	505	1,580	293 103	2,834
36	433	380	1,186	100	2,099
37	456	401	1,251	105	2,213
38	455	406	1,266	146	2,273
39	490	429	1,340	155	2,414

8.5.2.7 Liquid-Metal Pumps

The cost evaluation of the liquid-metal recirculation and feed pumps was based on CRBRP intermediate pump costs and on engineering judgements for the reduced range of topping cycle pump performance characteristics in Table 8.12. The cost evaluation reflects pump costs based on commercial standards rather than on the RDT standards of the CRBRP pumps. The pump costs also include allowances for the shorter pump shaft lengths than those designed for CRBRP.

8.5.2.8 Liquid-Metal Piping

The liquid-metal piping was cost evaluated as welded pipe under ANSI B-31 Specification. Three tables are provided which show in detail the cost breakdown for pipe sizes of interest in the liquid-metal subsystem. The tables includes cost of material, fittings, shop fabrication, and shop support (which gives the manufacturing cost). The installation includes field erection and support costs. Finally, total installed costs of insulation and trace heating is added on. For simplicity the material cost, which includes piping material, insulation, and trace heating was estimated to be 75% of the total installed cost. The installation cost was, therefore, 25% of the installed cost for each pipe size. These cost values are considered to be ± 5% accurate.

Table 8.21 lists the costs of stainless steel piping. Table 8.22 presents the costs of Incoloy 800 piping. The cost of Incoloy 800 pipe was assumed to be twice the cost of stainless, fabrication 1.5 times more costly, and field erection twice as much as for stainless. Table 8.23 represents the cost evaluation of Haynes 188. The Haynes 188 material was assumed to cost six times as much as stainless. The shop fabrication was assumed to be twice as much, and field erection three times as expensive, as stainless steel. These cost estimates are assumed to be accurate within 5%.

8.5.2.9 Liquid-Metal Inventory

Liquid-metal inventory was evaluated on the basis of information supplied by Callery Chemical Company. The potassium inventory was

Table 8.21 - Costs of Stainless Steel Welded Pipe under ANSI B-31 Specification, $/ft

Pipe Size, in	8	9	10	30	48
Cost	22.70	24.90	27.00	121.90	1,063.90
Fitting	26.90	37.50	48.10	426.70	552.10
Fabrication	36.20	38.80	41.50	181.20	223.70
Support	120.40	125.90	131.40	274.40	274.40
Total		227.10	248.00	1,017.80	2,114.10
Field Erection	40.20	57.90	75.60	202.10	316.50
Support	35.90	35.90	35.90	35.90	35.90
Insulation	14.20	15.50	16.70	51.00	51.00
Trace	54.60	59.70	64.80	170.00	170.00
		111.10	117.40	256.90	
Total Installed		396.10	441.00	1,476.80	2,687.50
M = 75% x Tot. Inst.		300.00	330.00	1,100.00	2,000.00
I = 25% x Tot. Inst.		100.00	110.00	380.00	690.00

Table 8.22 - Cost of Incoloy 800 Welded Pipe, $/ft

Pipe Size, in	9	10	30	48
Cost 2 x SS	49.80	54.00	243.80	*
Fittings	37.50	48.10	426.70	
Fabrication 1.5 x SS	58.20	62.25	271.80	
Support	125.90	131.40	274.40	
	271.40	295.75	1,216.70	
Field Erection 2 x SS	115.80	151.20	404.20	
Support	35.90	35.90	35.90	
Insulation	15.50	16.70	51.00	
Trace	59.70	64.80	170.00	
	111.10	117.40	256.90	
Total Installed	498.30	564.35	1,877.80	3,411.00
M = 75% Tot.Inst.	= 375.00	425.00	1,400.00	2,560.00
I = 25% Tot.Inst.	= 125.00	140.00	480.00	850.00

*Assume Total Inst. = 1.27% SS Inst.

Table 8.23 - Cost of HA-188 Welded Pipe, $/ft

Pipe Size, in	9	10	30	48
Cost = 6 x SS	149.40	162.00	731.40	*
Fittings	37.50	48.10	426.70	
Fabrication 2 x SS	77.60	83.00	362.40	
Support	125.90	131.40	274.40	
Total Shop	390.40	424.80	1,794.90	
Field Erection 3 x SS	173.70	226.80	606.30	
Support	35.90	35.90	35.90	
Insulation	15.50	16.70	51.00	
Trace	59.70	64.80	170.00	
Total Extras	111.10	117.40	256.90	
Total Installed	675.20	769.00	2,658.10	4,834.80
M = 75% Tot.Inst.	= 500.00	575.00	2,000.00	3,600.00
I = 25% Tot.Inst.	= 175.00	190.00	660.00	1,240.00

*Assume Total Inst. = 180% SS

evaluated at \$3.70/kg (\$1.68/lb). The cesium inventory was evaluated at \$39.68/kg (\$18.00/lb) on the basis of 100,000 lb/31.53 Ms (1 yr). The potassium costs are considered to be ± 5% and the cesium ± 20%.

8.5.2.10 Liquid-Metal Auxiliary Subsystem

The liquid-metal auxiliary subsystems were evaluated from CRBRP auxiliary liquid-metal subsystems. Auxiliary subsystem costs were partially scaled for the Rankine topping cycle based on inventory, piping length, and component sizes.

Table 8.24 lists the costs evaluated for each auxiliary subsystem.

Table 8.24 - Liquid-Metal Auxiliary Subsystem Costs

Subsystem	Material $\times 10^{-3}$, \$	Installation $\times 10^{-3}$, \$
Receiving and Processing	6,200	2,000
Impurity Monitoring	800	250
Inert Gas Receiving and Processing	1,700	400
Leak Detection	250	200
Trace Heating	2,500	2,000
Total	11,450	7,100

The total material and installation cost is approximately 10% of the liquid-metal subsystem cost and 5% of the total plant direct costs. The assumed accuracy of ± 15% is negligible when compared to the liquid-metal subsystem cost.

8.5.2.11 Summary of Liquid-Metal Subsystem Direct Costs

The direct costs of the liquid-metal components and auxiliary systems are summarized in Table 8.25 for the preliminary optimum

Table 8.25 - Summary of Liquid-Metal Subsystem Direct Costs, Preliminary Optimum Potassium Rankine Topping Cycle

	Material Cost $\times 10^{-6}$, \$	Installation Cost $\times 10^{-6}$, \$
Boiler	60.672	34.128
Turbine	24.000	2.160
Condenser-Steam Gen.	6.160	2.640
Hot well	2.700	0.440
Piping	5.063	1.696
Drum	2.360	0.360
Recirculation Pump	0.860	0.069
Feed Pump	1.440	0.115
Inventory	0.640	0.013
Storage Tank	5.200	0.600
Dump Tank	2.280	0.344
Receiving and Processing	6.300	2.000
Impurity Monitor	0.800	0.250
Cover Gas	1.700	0.400
Leak Detection	0.250	0.200
Trace Heating	2.500	2.000
	122.925	47.415
Total Direct Cost	\$170,340,000	

potassium Rankine topping cycle (Point 49). Much of the costing data is based on engineering judgement rather than on actual cost estimates. The results are of the proper magnitude and are expected to be accurate to ± 30%. Such an error to the total plant capitalization is approximately 7%, which is within the accuracy for similar plant estimates. Such an error will not change the conclusions of this study, for which the systematic cost evaluation should provide reasonable comparisons, regardless of the absolute validity. The cost difference evaluated in the cases considered are meaningful.

Improvement in cost estimates for the Rankine topping cycle is possible only through greater efforts on the part of liquid-metal component designers and manufacturers, particularly for the liquid-metal turbine.

8.6 Analysis of Overall Cost of Electricity

8.6.1 Matrix of Component and Parameter Variations

The work scope of this study required that the liquid-metal Rankine topping cycle be investigated for a variety of furnace combustor types, fuels (coal), cycle configurations, major cycle parameters, and power levels. The matrix of the 50 parametric points for the liquid-metal vapor Rankine topping cycle is shown on Table 8.6. Base Case 1, the pressurized fluidized bed, and Base Case 2, the pressurized furnace, are listed on Table 8.6 as Points 1 and 4, respectively.

The first 39 cases served as a sensitivity study to determine the effects of component and parameter variation for a constant power level. This sensitivity study was then used to determine a preliminary optimum case by combining the components and parameter values which individually provided the best cycle performance and which were estimated to be cost effective. The economic model was not available for a cost evaluation of the sensitivity study.

This preliminary optimum cycle was used to determine the effect of power level variation for a PFB plant (Points 40, 41, 42, and 49) and

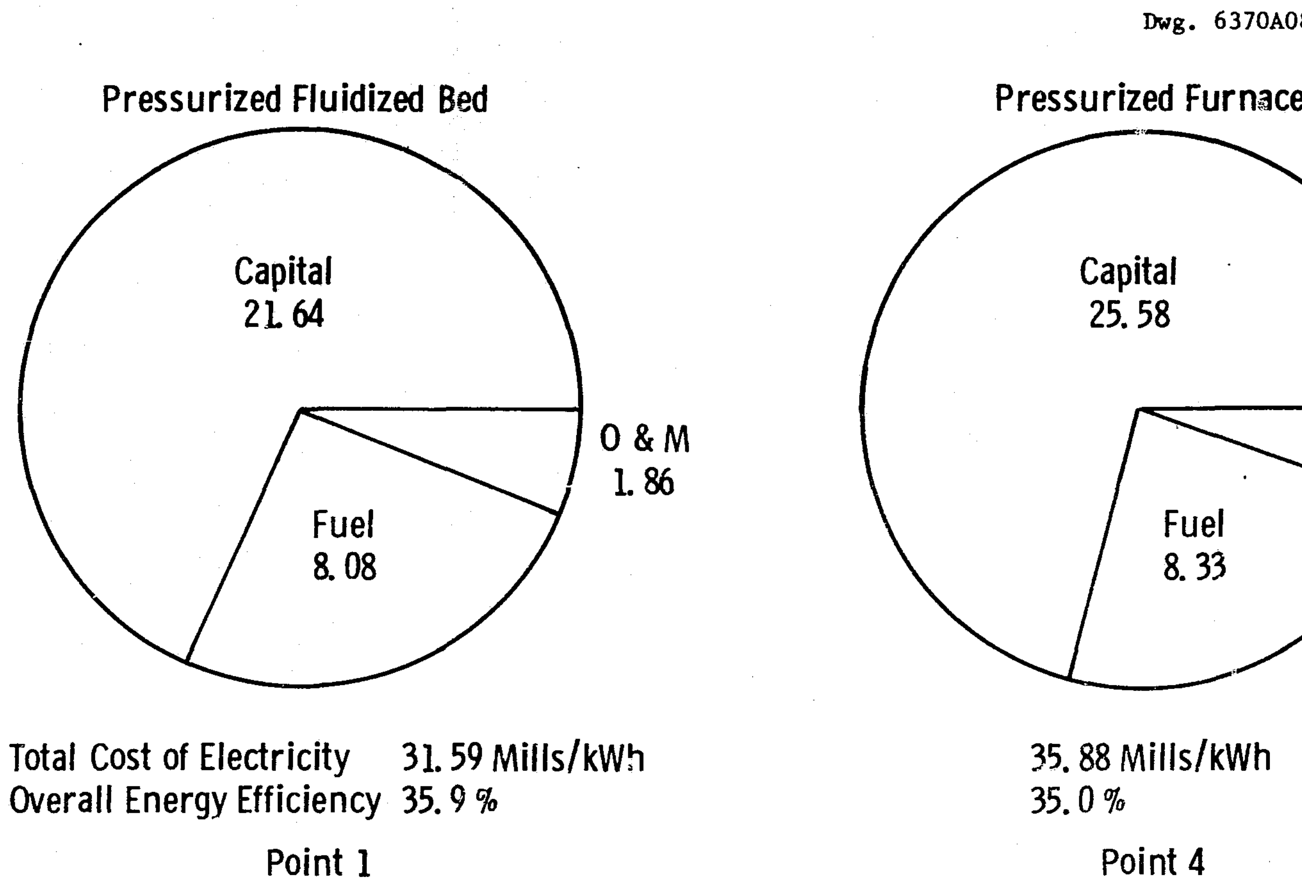


Fig. 8.18—Performance and cost of electricity for a pressurized fluidized bed boiler and pressurized furnace 1200 MWe plants burning Illinois No. 6

a PF plant (Points 43, 44, 45, and 50). Points 46, 47, and 48 were used to study the effects of power level variation and cesium as the working fluid in a PFB plant.

The economic, natural resources requirement, and environmental intrustion analyses were performed on the 50 points calculated after the performance analysis was completed. Availability of the economic analysis at an earlier date would have resulted in a more cost-effective and more efficient preliminary optimum cycle than that depicted in Points 40 to 50. This is particularly true in the selection of coal, gas-heated economizer utilization, and gas turbine inlet temperature.

8.6.2 Effect of Furnace-Combustor Type

In Section 8.2 the plant configurations and operating state points of the PFB and PF base case plant were shown on Tables 8.7 and 8.9, respectively. The effect of furnace-combustor type on performance and cost of electricity for the PFB and PF base cases using Illinois No. 6 coal are illustrated on Figure 8.18. The higher PFB cycle efficiency and its lower cost of electricity relative to the PF is due to the high cost and ∿ 90% efficiency of the gasifier to produce the low-Btu gas from the coal. The high cost of electricity from the PF gasifier system is due to the higher capital cost, as shown in the chart on Figure 8.18. The higher fuel and maintenance costs for the PF indicate the gasifier inefficiency. On the basis of lower cost and higher efficiency the PFB is the recommended furnace-combustor type for the liquid-metal Rankine topping cycle.

8.6.3 Effect of Coal Type on PFB

Three types of coal were evaluated for the liquid-metal Rankine topping cycle. The three coals and their effect on the performance and cost of a PFB plant are illustrated on Figure 8.19. Illinois No. 6 bituminous coal produces a higher cycle efficiency and lower fuel cost, as shown in the chart, due to its higher heating value. For this reason the Illinois No. 6 was selected for the preliminary optimum cycle prior to the availability of the cost evaluation. However, further analysis

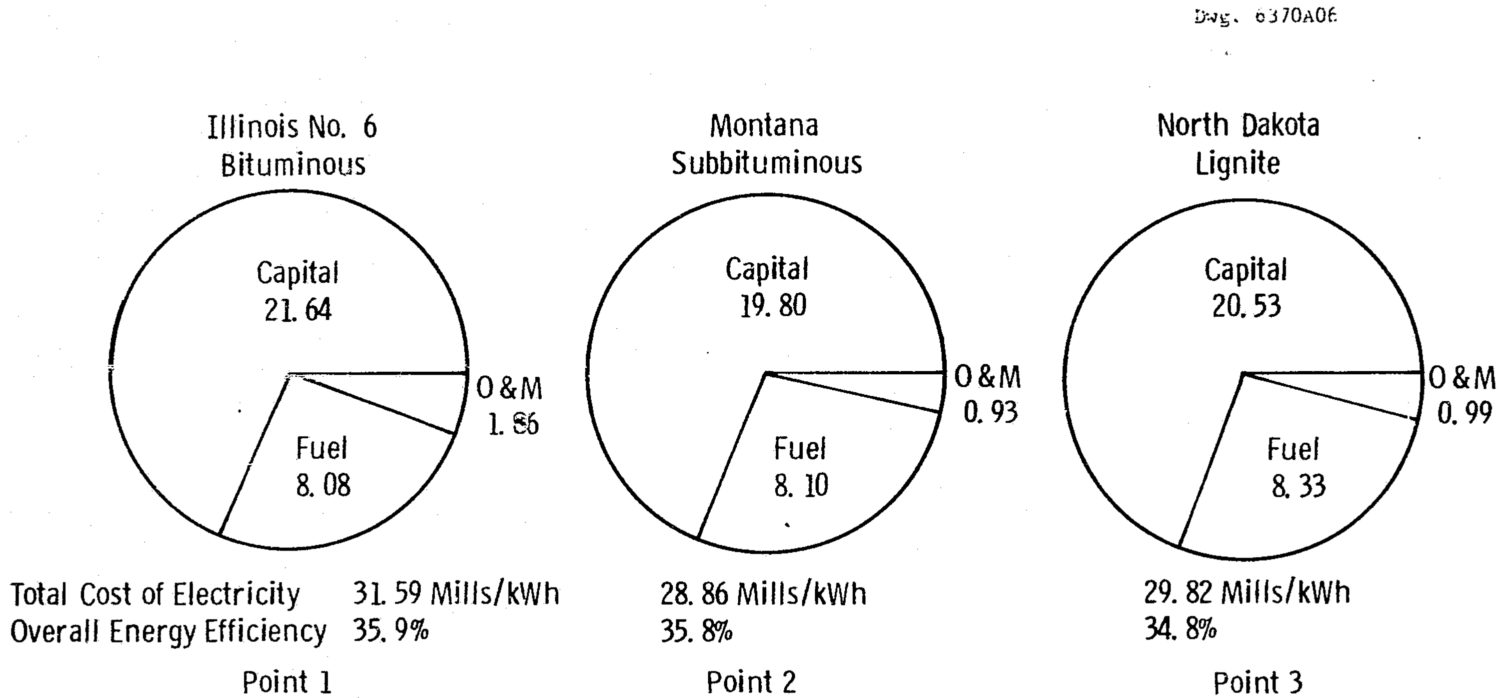


Fig. 8. 19—Effect of coal type on pressurized fluidized bed boiler plant performance and cost of electricity

indicates that the Montana subbituminous produces the lowest cost of electricity, 8.6% less than Illinois No. 6, with only a 0.3% loss in cycle efficiency. The high cost of using the Illinois No. 6 is due to its high sulfur content ($\sim$ 4.9 times higher than the Montana or North Dakota). The high sulfur content requires much more dolomite for sulfur removal, as indicated by the operating and maintenance costs, which are almost double those of the other two coals. The higher sulfur content is also reflected in the capital cost for larger fuel handling and process sytems and for waste disposal.

Thus, the recommended fuel for the liquid-metal Rankine topping cycle is Montana subbituminous, not Illinois No. 6 bituminous, as shown in Table 8.6 for the preliminary optimum cycle.

8.6.4 Effect of Component and Parameter Variation on PFB

The matrix of points investigated in this study included variations of components and parameters in the combustor pressurizing subsystem, the steam subsystem, and type of heat rejection for both PFB and PF plants. These points are listed and numbered in Table 8.6. The performance and state point values for all cases are included in Appendix A 8.1 on computer printout sheets. The optimum point of each component or parameter variation is plotted against the base case cycle efficiency and cost of electricity for the 1200 MWe PFB plant burning Illinois No. 6 coal in Figure 8.20. Reference to the matrix of parametric points on Table 8.6 shows the range of values investigated for each of the components and parameters listed on the bottom of the bar chart of Figure 8.20.

Notice that most of the optimum points are the same as the base case. Had the points been run with the optimum coal, Montana subbituminous, all the optimum points would show improvement over Base Case 1.

The use of a recuperator to preheat air in the combustor pressurizing subsystem resulted in an increase in cycle efficiency of 1.4% over cycles with no recuperation for recuperator effectiveness of both $\varepsilon = 0.70$ and $\varepsilon = 0.80$. Thus, recuperation was found to be unjustified for a 15 to 1 pressure ratio. The optimum point was Base Case 1 with no

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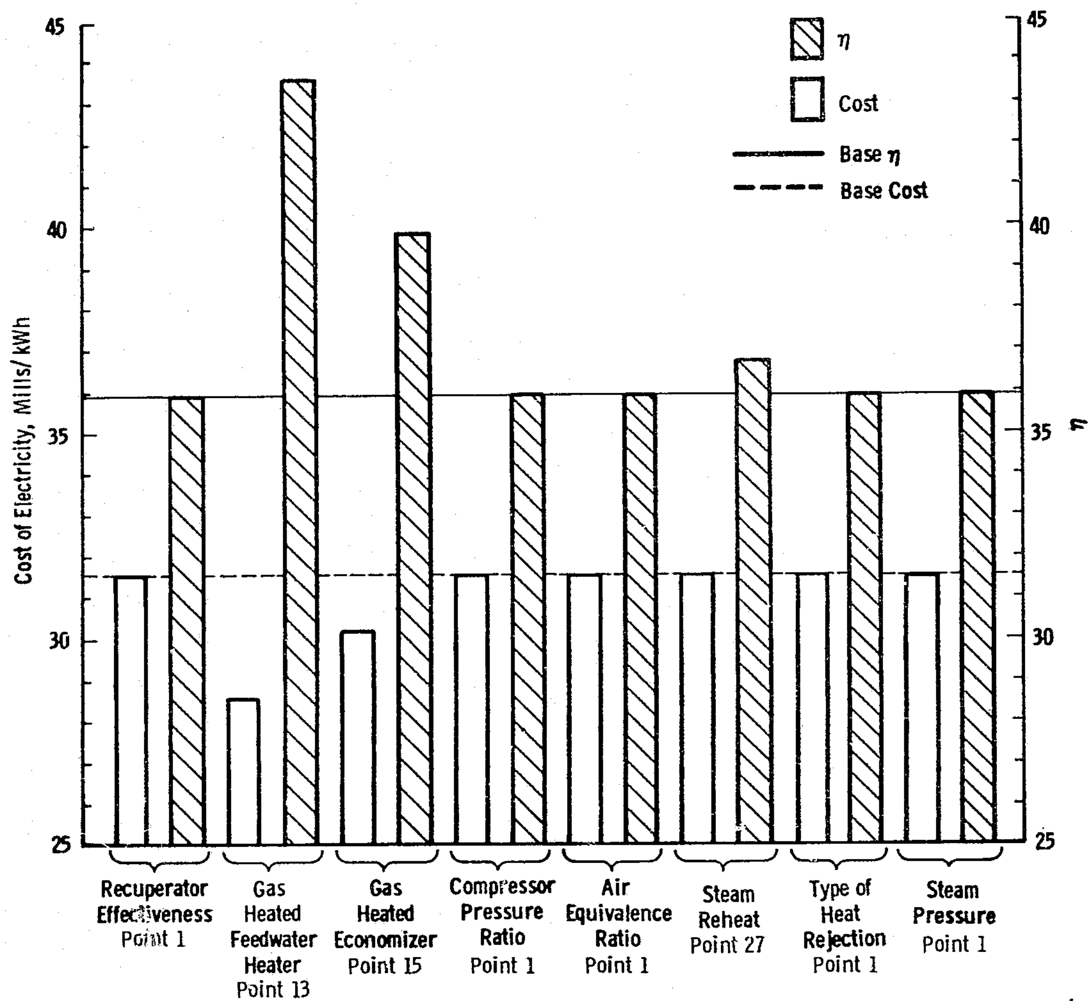

Fig. 8.20—Effect of optimum components and optimum parameters on pressurized fluidized bed performance and cost of electricity

recuperation. Similar results were obtained for recuperation with a PF plant.

Although not shown on Figure 8.20, a once-through liquid-metal subsystem was investigated for PFB and PF plants. The cycle efficiencies were the same as those of the base cases, with a slight cost advantage for a once-through system. On the basis of ease of control and avoidance of DNB with all its problems and uncertainties, the recirculation system was selected as optimum.

In the case of a gas-heated feedwater heater, the variation was no feedwater heater or incorporation of a gas feedwater heater in parallel with the steam turbine extraction feedwater string. As shown on Figure 8.20, the incorporation of the feedwater had a significant effect on the performance and cost of electricity. The cycle efficiency increased 21%, and the cost decreased 9.7%, in comparison with Base Case 1. For a PF plant the improvement was comparable. Incorporation of a gas-heated feedwater heater, therefore, was selected.

The next variation shown on Figure 8.20 is a gas-heated economizer. Again, the options were either inclusion or omission of the economizer installed between the condenser-steam generator and the final feedwater heater. The cycle efficiency increased 10%, with a 4% reduction in the cost of electricity for a PFB plant.

In the initial design of the liquid-metal vapor turbine, extraction feedheating was determined to be inappropriate. Moisture separation was also ruled out because of the low pressure available and the inability to take the momentum losses. Hence, liquid-metal feedheating was not considered in this study.

One of the combustor pressurizing subsystem parameters investigated was the combustor pressure level. Values of [0.506, 1.013, and 1.519 MPa (5, 10, and 15 atm)] were used [1.519 MPa (15 atm) being the base case]. As illustrated by the appropriate bar chart in Figure 8.20, a 15:1 compressor pressure ratio was the optimum of the values studied.

The results showed that cycle performance increased, while the cost of electricity decreased, with increasing pressure ratio.

The final combustor pressurizing subsystem parameter studied was the air equivalence ratio, ϕ_{air}. In addition to the minimum value of 1.2 (base case) for fluidized bed combustion of solid fuels, values of ϕ_{air} equal to 2.0 and 3.0 were used. The investigation showed that values significantly higher than 1.2 have disastrous effects on the liquid-metal topping cycles. For ϕ_{air} of 2.0 and 3.0 the cycle efficiency compared to the base case ϕ_{air} of 1.2 decreased 46 and 69%, respectively; while the cost of electricity increased 40 and 110%, respectively. The base case ϕ_{air} of 1.2 was selected as optimum.

With regard to the steam subsystem, the effect of one stage of steam reheat was compared to a nonreheat cycle. The plot shown on Figure 8.20 is the optimum point for a 24.136 MPa (3500 psi) gauge, 811°K/811°K (1000°F/1000°F) reheat steam cycle. It was selected as optimum from among single reheat and nonreheat cycles at 24 and 16 MPa (3500 and 2400 psi) gauge with temperatures at 811, 866, and 922°K (1000, 1100, and 1200°F). For both nonreheat and reheat cycles, and for both pressures considered, the 866 and 922°K (1100 and 1200°F) temperatures showed increasing improvement in efficiency but also increasing costs. At the two higher temperatures there are materials problems to contend with.

For the selection of steam pressure, the base case value of 24.132 MPa (3500 psi) gauge showed an advantage over 16.547 MPa (2400 psi) gauge for both performance and cost of electricity at 811°K (1000°F) steam temperature, as expected. Additionally, the steam pressure of 24.132 MPa (3500 psi) gauge was selected as optimum because at supercritical pressure DNB and its associated problems and uncertainties are avoided.

The base case heat rejection was a wet cooling tower. Once-through and dry cooling tower heat rejection systems were also investigated. Even though the once-through has a 2% advantage in both cycle efficiency and cost of electricity, the wet cooling tower system was selected for environmental reasons. Based on a 5% differential in efficiency and cost, the wet cooling towers were selected over dry cooling tower heat rejection. Figure 8.20 shows the bar chart for the optimum heat rejection selection.

8.6.5 Effect of System Temperatures on PFB

The study also included the variation of the major cycle temperatures. Figure 8.21 shows the effects of varying the inlet temperatures of the three turbines on the cycle efficiency and cost of a PFB plant at 1200 MWe.

The uppermost curve demonstrates the results of lowering the gas turbine inlet temperature from the 1255°K (1800°F) maximum allowable fluidized bed temperature to 1144°K (1600°F). Note the 6% increase in cycle efficiency as the gas turbine inlet temperature decreases to 1144°K (1600°F). Due to the delay in the availability of the costing model, the increased cycle efficiency was the basis for selecting the gas turbine temperature for the preliminary optimum plant. It was assumed that the increased heat transfer area and, hence, increased cost of the furnace-combustor due to the reduced gas-side temperature, would not increase the plant capital cost significantly; that the lower temperature would mitigate cost increases by allowing the use of less exotic materials; and that the improved efficiency would reduce the increase in the cost of electricity. As indicated on Figure 8.21a the capital cost at 1144°K (1600°F) gas inlet temperature decreased below the 1255°K (1800°F) capital cost. Although not shown, the cost of electricity decreased 2.0 and 0.4% for 1144 and 1200°K (1600 and 1700°F), respectively, when compared to the base case gas turbine inlet temperature of 1255°K (1800°F). The recommended gas turbine inlet temperature of 1144°K (1600°F) was selected, with 1255°K (1800°F) as an alternate.

The second set of curves, Figure 8.21b, shows the effects of variations in liquid-metal turbine inlet temperatures. A constant temperature differential of 166.7°K (300°F) was assumed from turbine inlet to the liquid-metal condenser-steam generator. The liquid-metal system was investigated at three conditions 1033°K inlet/866°K condenser

Curve 682995-3

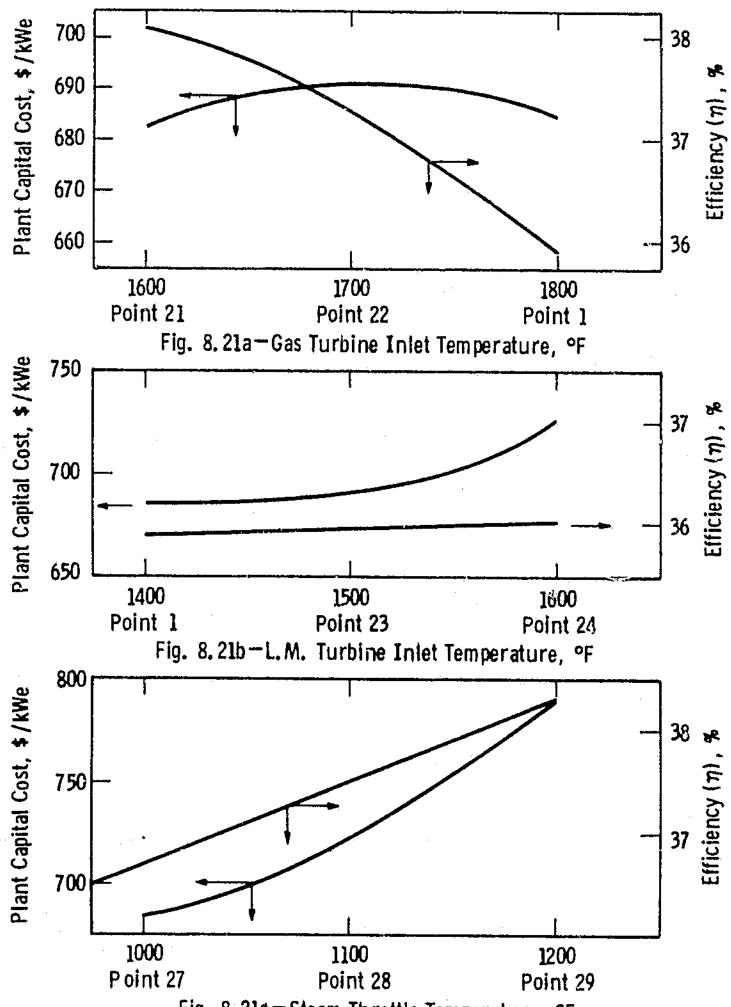

Fig. 8.21a—Gas Turbine Inlet Temperature, °F

Fig. 8.21b—L.M. Turbine Inlet Temperature, °F

Fig. 8.21c—Steam Throttle Temperature, °F

Fig. 8.21—Effect of system temperatures on performance and cost of pressurized fluidized bed boiler plant

(1400°F/1100°F), 1089°K/922°K (1500°F/1200°F), and 1144°K/978°F (1600°F/1300°F). The gas turbine inlet temperature and steam turbine inlet temperatures were held constant at 1255 and 811°K (1800 and 1000°F), respectively. As Figure 8.21b demonstrates, the capital cost increased as much as 4% with increasing liquid-metal temperatures over the 1033°K (1400°F) base case. This was caused by the increased heat transfer area and the cost of construction materials in the liquid-metal subsystem. The cycle efficiency increase is negligible, considering the uncertainties of this study. With a definite economic incentive to minimize the liquid-metal temperatures, the 1033°K/866°K (1400°F/1100°F) liquid-metal temperatures were selected for investigation in Task II. The lower liquid-metal temperatures mitigate materials and development problems, particularly in the condenser-steam generator.

Up to this point all the parameter variations have been individual variations. Figure 8.21c shows the effect of steam throttle temperature variations; but for the steam temperatures the liquid-metal turbine temperature also varied (see Table 8.6, cases 23 through 35). For the steam temperatures listed in Figure 8.21c, the corresponding liquid-metal turbine inlet temperature is found directly above in Figure 8.21b. The gas turbine inlet temperature was held constant at 1255°K (1800°F). The values plotted in Figure 8.21c were the results for a 24.132 MPa (3500 psi) gauge single reheat steam cycle. The figure shows that both cycle efficiency and capital cost increase as the steam temperature increases: but when compared to the 811°K (1000°F) steam temperature case, the increase in capital cost is more than twice the increase in cycle efficiency for the 922°K (1200°F) case. The cost of electricity is 3.2 and 9.2% higher than 811°K (1000°F) steam for 866 and 922°K (1100 and 1200°F), respectively. Again, this is the result of higher costs for high-temperature materials to meet the temperature requirements in the steam turbine and the liquid-metal subsystem.

To ease the high cost and reduce the material and development problem, a steam throttle temperature of 811°K (1000°F) was recommended.

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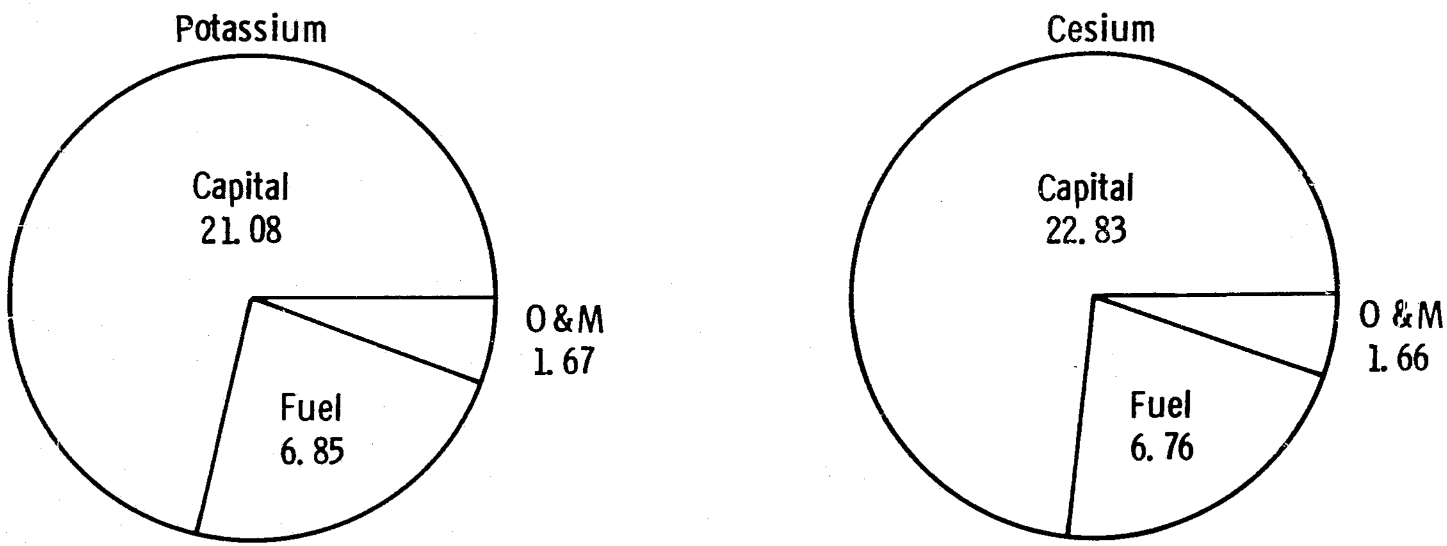

	Potassium	Cesium
Total Cost of Electricity	29.60 Mills/kWh	31.25 Mills/kWh
Overall Energy Efficiency	42.4%	42.9
	Point 49	Point 46

Fig. 8.22—Performance and cost of electricity of a potassium and a cesium topping cycle for best study plant configuration

The parametric analysis described above concluded with the selection of the preliminary optimum plant configuration and operating parameters, as shown in Point 49 of Table 8.6.

8.6.6 Effect of Working Fluid on Preliminary Optimum Plant

As described in Section 8.2, an initial assumption in the parametric analysis was that cesium would not be competitive with potassium as the working fluid for the liquid-metal Rankine topping cycle. The basis for this assumption was the limited supply of cesium available and the initially high cost estimates. The initial cesium inventory requirement was approximately 635 Mg (1,400,000 lb). The availability of cesium data was also limited. Thus, the parametric analysis of the metal vapor Rankine topping cycle concentrated on potassium as the working fluid. The results of that analysis were assumed to pertain to cesium within a reasonable degree of accuracy for preliminary evaluation.

Points 46, 47, and 48 of Table 8.6 define the cesium topping cycle and power level variation. Points 40, 41, 42, and 49 define the potassium topping cycle. Except for the working fluid these cases are similar. The results of Point 49 and 46 are shown on Figure 8.22 for potassium and cesium, respectively.

Due to the preliminary nature of the cesium turbine design and the lack of cesium data available, the large uncertainties of the cesium cycle tend to reduce the feasibility of application when compared with potassium. The results definitely demonstrated that cesium is competitive with potassium as the working fluid in a metal vapor topping cycle. These results, however, contain too many uncertainties to make a final selection at this time. Further effort, particularly in the design of the cesium turbine, is required.

8.6.7 Effect of Nominal Power Variation

The final variation analyzed in this study was nominal power level. Figure 8.23 shows the effect of various power applications on preliminary optimum plant configurations with cesium and potassium as the

Curve 683061-A

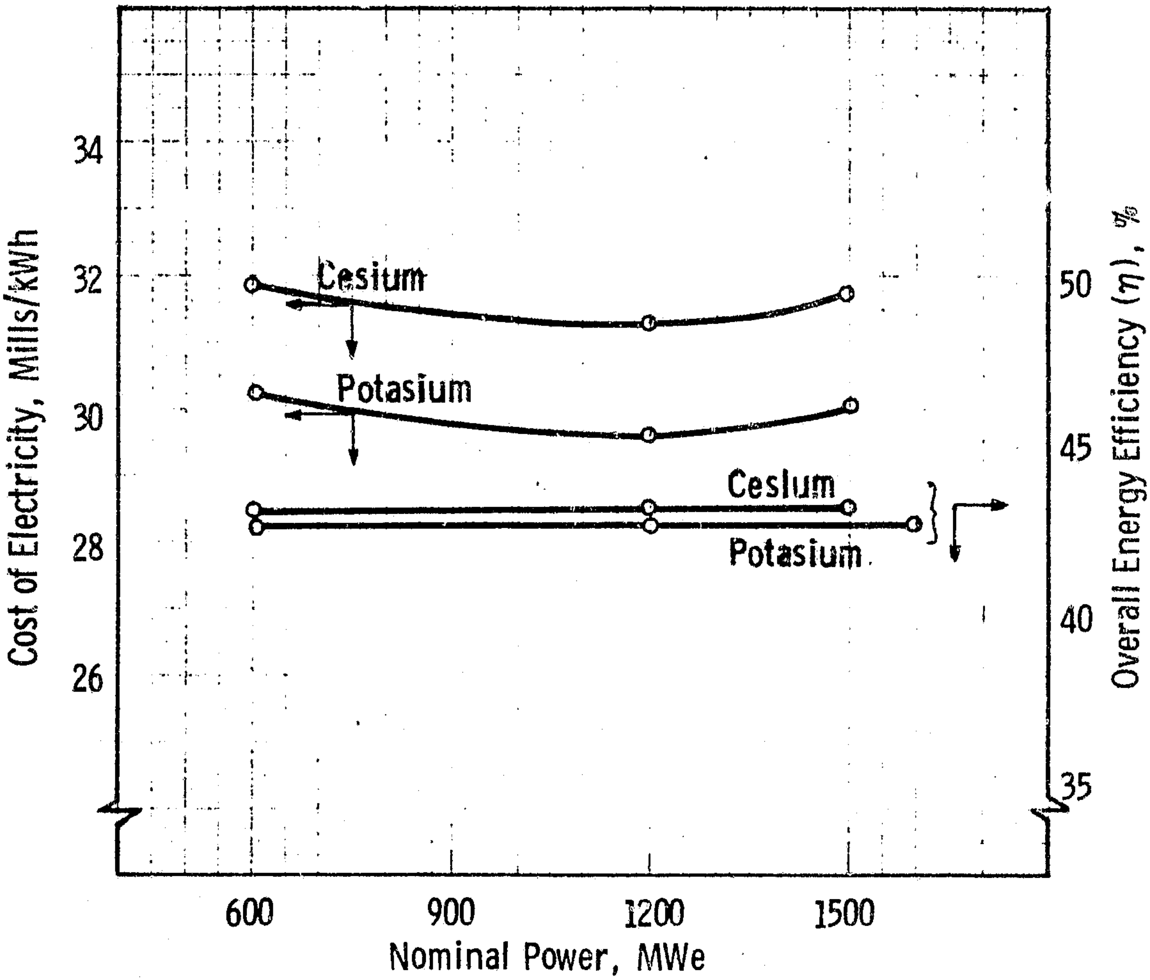

Fig. 8.23—Effect of nominal power on performance and cost of electricity for pressurized fluidized bed boiler

working fluids. The dashed curves show the relatively constant cycle efficiency over the range of power applications selected. The solid curves demonstrate the reduction in the cost of electricity as the nominal plant rating increases.

8.6.8 Summary Sheets

The natural resource requirements and environmental intrusion for Base Cases 1 and 2 are shown on the summary sheets in Tables 8.26 and 8.27, respectively. The sizes, weights, and costs of the major liquid-metal subsystem components and cooling towers are also included on the summary sheets.

Although they are not recommended points for Task II, the summary sheets for the preliminary optimum plants with potassium and cesium are included as Tables 8.28 and 8.29. They are a close approximation of the final results and improvements expected for the further optimization of the liquid-metal vapor Rankine topping cycle.

8.6.9 Additional Considerations

The overall costs and efficiencies of the 50 parametric points are included in Appendix A 8.2. Figure 8.24 is a plot of the overall efficiency versus capital cost for several of the cases considered. Figure 8.25 is a plot of the capital cost versus cost of electricity for the same cases.

In analyzing the overall cost of electricity, a new optimum cycle parameter and component configuration may be extrapolated. The plant will be similar to the preliminary optimum plant except for a 1255°K (1800°F) gas turbine inlet temperature and the burning of Montana subbituminous coal. A line AC has been drawn through Base Case 1 and the gas feedwater heater Point 13 in both Figures 8.24 and 8.25. Drawing the line A'C' parallel to AC through the subbituminous coal (Point 2) determines the locus of subbituminous coal, gas feedwater heater plants with a non-reheat steam plant.

On both figures line EG is drawn through the bituminous coal plant (Point 1) and the subbituminous coal plant (Point 2). Parallel line

Table 8.26 - Summary Sheet Liquid-Metal Rankine Topping Cycle Base Case No. 1, Point 1

Parameter Values	
Net Power (MWe)	1133.6
Combustor Pressurizing Subsystem	
Combustor type	PFB
Fuel	Illinois No. 6
Gas turbine inlet temp., °F	1800
Compressor pressure ratio	15
Air equivalence ratio	1.2
Liquid-Metal Subsystem	
Fluid	K
Turbine inlet temperature, °F	1400
Condensing temperature, °F	1100
Circulation ratio	2.5:1
Steam Turbine Subsystem	
Turbine inlet temperature, °F	1000
Turbine inlet pressure, psig	3500
Reheat temperature, °F	NA
Condensing pressure, in Hg abs	3.5
Heat Rejection	Wet towers

(a)

Performance and Cost	
Power Plant Efficiency, %	35.9
Overall Energy Efficiency, %	35.9
Capital Cost, 10^6 $	776.1
Capital Cost, $/kWe	684.6
Cost of Electricity, mills/kWh	31.58

(b)

Natural Resources	
Coal, lb/kWh	0.881
Sorbent, lb/kWh	0.466
Total Water, gal/kWh	0.767
Cooling water	0.611
Gasifier process	0.000
Condensate makeup	0.006
Waste-handling slurry	0.096
Scrubber waste	0.053
NO_x suppression	0.000
Total Land, acres/100 MWe	114.6
Main plant	16.5
Disposal land	77.2
Access railroad	20.8

(c)

Major Components

Component	Size, ft (W x L (or D) x H)	Weight, 10^3 lb	Cost Mfg., 10^3 $	FOB Plant, $/kWe	Units Required	Total Cost, 10^3 $
PFB	13.6 x 121	700	5,820	4.98	16	93,160
L-M Turbine			3,000	2.56	8	24,000
Condenser-Steam Generator	27.2	155	2,300	1.97	4	9,200
Cooling Tower	43 x 40 x 70		230	0.20	13	2,990

(d)

Environmental Intrusion

	$lb/10^6$ Btu	lb/kWh
SO_2	0.723	0.0068
NO_x	0	0
HC	0	0
CO	0	0
Particulates	0.0365	3.45×10^{-4}
	Btu/kWh	
Heat to Water	2904	
Heat, Total Rejected	5239	
	lb/kWh	lb/day
Wastes		
Ash	0.084	2.36×10^6
Spent sorbent	0.464	13.03×10^6

(e)

Table 8.27 - Summary Sheet Liquid-Metal Rankine Topping Cycle Base Case No. 2, Point 4

Parameter Values	
Net Power (MWe)	1144.4
Combustor Pressurizing Subsystem	
Combustor type	PFB
Fuel	Illinois No. 6
Gas turbine inlet temp., °F	1800
Compressor pressure ratio	15
Air equivalence ratio	1.2
Liquid-Metal Subsystem	
Fluid	K
Turbine inlet temperature, °F	1400
Condensing temperature, °F	1100
Circulation ratio	2.5:1
Steam Turbine Subsystem	
Turbine inlet temperature, °F	1000
Turbine inlet pressure, psig	3500
Reheat temperature, °F	NA
Condensing pressure, in Hg abs	3.5
Heat Rejection	Wet towers

(a)

Performance and Cost	
Power Plant Efficiency, %	34.8
Overall Energy Efficiency, %	35.0
Capital Cost, 10^6 $	926.1
Capital Cost, $/kWe	809.2
Cost of Electricity, mills/kWh	35.88

(b)

Natural Resources	
Coal, lb/kWh	0.904
Sorbent, lb/kWh	0.478
Total Water, gal/kWh	0.813
Cooling water	0.601
Gasifier process	0.052
Condensate makeup	0.006
Waste-handling slurry	0.099
Scrubber waste	0.054
NO_x suppression	0.000
Total Land, acres/100 MWe	113.9
Main plant	17.3
Disposal land	75.98
Access railroad	20.65

(c)

Major Components						
Component	Size, ft (W x L (or D) x H)	Weight, 10^3 lb	Cost Mfg., 10^3 $	FOB Plant, $/kWe	Units Required	Total Cost, 10^3 $
PFB	14.5 x 25	220	2,200	1.95	8	17,600
L-M Turbine			3,000	2.66	8	24,000
Condenser-Steam Generator	27.2 (sphere)	155	2,300	2.04	4	9,200
Cooling Tower	43 x 40 x 70		230	0.20	13	2,990

(d)

Environmental Intrusion		
	$lb/10^6$ Btu	lb/kWh
SO_2	0.723	0.0074
NO_x	0	0
HC	0	0
CO	0	0
Particulates		
	Btu/kWh	
Heat to Water	2990	
Heat, Total Rejected	5730	
	lb/kWh	lb/day
Wastes		
Ash	0.090	2.44×10^6
Spent sorbent	0.498	13.4×10^6

(e)

Table 8.28 - Summary Sheet Liquid-Metal Rankine Topping Cycle, Point 49

Parameter Values	
Net Power (MWe)	1140.0
Combustor Pressurizing Subsystem	
Combustor type	PFB
Fuel	Illinois No. 6
Gas turbine inlet temp., °F	1600
Compressor pressure ratio	15
Air equivalence ratio	1.2
Liquid-Metal Subsystem	
Fluid	K
Turbine inlet temperature, °F	1400
Condensing temperature, °F	1100
Circulation ratio	2.5:1
Steam Turbine Subsystem	
Turbine inlet temperature, °F	1000
Turbine inlet pressure, psig	3500
Reheat temperature, °F	1000
Condensing pressure, in Hg abs	3.5
Heat Rejection	Wet towers

(a)

Performance and Cost	
Power Plant Efficiency, %	42.4
Overall Energy Efficiency, %	42.4
Capital Cost, 10^6 $	760.3
Capital Cost, $/kWe	666.9
Cost of Electricity, mills/kWh	29.60

(b)

Natural Resources	
Coal, lb/kWh	0.746
Sorbent, lb/kWh	0.395
Total Water, gal/kWh	0.737
Cooling water	0.603
Gasifier process	0.000
Condensate makeup	0.007
Waste-handling slurry	0.082
Scrubber waste	0.045
NO_x suppression	0.000
Total Land, acres/100 MWe	102.6
Main plant	16.4
Disposal land	65.4
Access railroad	20.7

(c)

Major Components

Component	Size, ft (W x L (or D) x H)	Weight, 10^3 lb	Cost Mfg., 10^3 $	FOB Plant, $/kWe	Units Required	Total Cost, 10^3 $
PFB	16.6 x 100	840	5,910	5.05	16	94,612
L-M Turbine			3,000	2.56	8	24,000
Condenser-Steam Generator	26.7 (sphere)	196	2,300	1.96	4	9,200
Cooling Tower	43 x 40 x 70		230	0.20	13	2,990

(d)

Environmental Intrusion

	$lb/10^6$ Btu	lb/kWh
SO_2	0.723	0.0058
NO_x	0	0
HC	0	0
CO	0	0
Particulates	0.043	3.46×10^{-4}
	Btu/kWh	
Heat to Water	3156	
Heat, Total Rejected	3934	
	lb/kWh	lb/day
Wastes		
Ash	0.072	2.01×10^6
Spent sorbent	0.395	11.1×10^6

(e)

Table 8.29 - Summary Sheet Liquid-Metal Rankine Topping Cycle, Point 46

Parameter Values	
Net Power (MWe)	1139.9
Combustor Pressurizing Subsystem	
Combustor type	PFB
Fuel	Illinois No. 6
Gas turbine inlet temp., °F	1600
Compressor pressure ratio	15
Air equivalence ratio	1.2
Liquid-Metal Subsystem	
Fluid	Cs
Turbine inlet temperature, °F	1400
Condensing temperature, °F	1100
Circulation ratio	2.5:1
Steam Turbine Subsystem	
Turbine inlet temperature, °F	1000
Turbine inlet pressure, psig	3500
Reheat temperature, °F	1000
Condensing pressure, in Hg abs	3.5
Heat Rejection	Wet towers

(a)

Performance and Cost	
Power Plant Efficiency, %	42.9
Overall Energy Efficiency, %	42.9
Capital Cost, 10^6 $	823.2
Capital Cost, $/kWe	722.2
Cost of Electricity, mills/kWh	31.25

(b)

Natural Resources	
Coal, lb/kWh	0.737
Sorbent, lb/kWh	0.390
Total Water, gal/kWh	0.780
Cooling water	0.649
Gasifier process	0.000
Condensate makeup	0.007
Waste-handling slurry	0.081
Scrubber waste	0.044
NO_x suppression	0.000
Total Land, acres/100 MWe	103.31
Main plant	16.4
Disposal land	64.6
Access railroad	22.33

(c)

Major Components

Component	Size, ft (W x L (or D) x H)	Weight, 10^3 lb	Cost Mfg., 10^3 $	FOB Plant, $/kWe	Units Required	Total Cost, 10^3 $
PFB	16 x 100	770	5,590	4.78	16	89,430
L-M Turbine			2,000	1.71	8	16,000
Condenser-Steam Generator	26.7 (sphere)	196	2,300	1.96	4	9,200
Cooling Tower	43 x 40 x 70		230	0.20	14	3,220

(d)

Environmental Intrusion

	$lb/10^6$ Btu	lb/kWh
SO_2	0.723	0.0054
NO_x	0	0
HC	0	0
CO	0	0
Particulates	0.0418	3.10×10^{-4}
	Btu/kWh	
Heat to Water	3214	
Heat, Total Rejected	3929	
	lb/kWh	lb/day
Wastes		
Ash	0.065	2.36×10^6
Spent sorbent	0.364	10.219×10^6

(e)

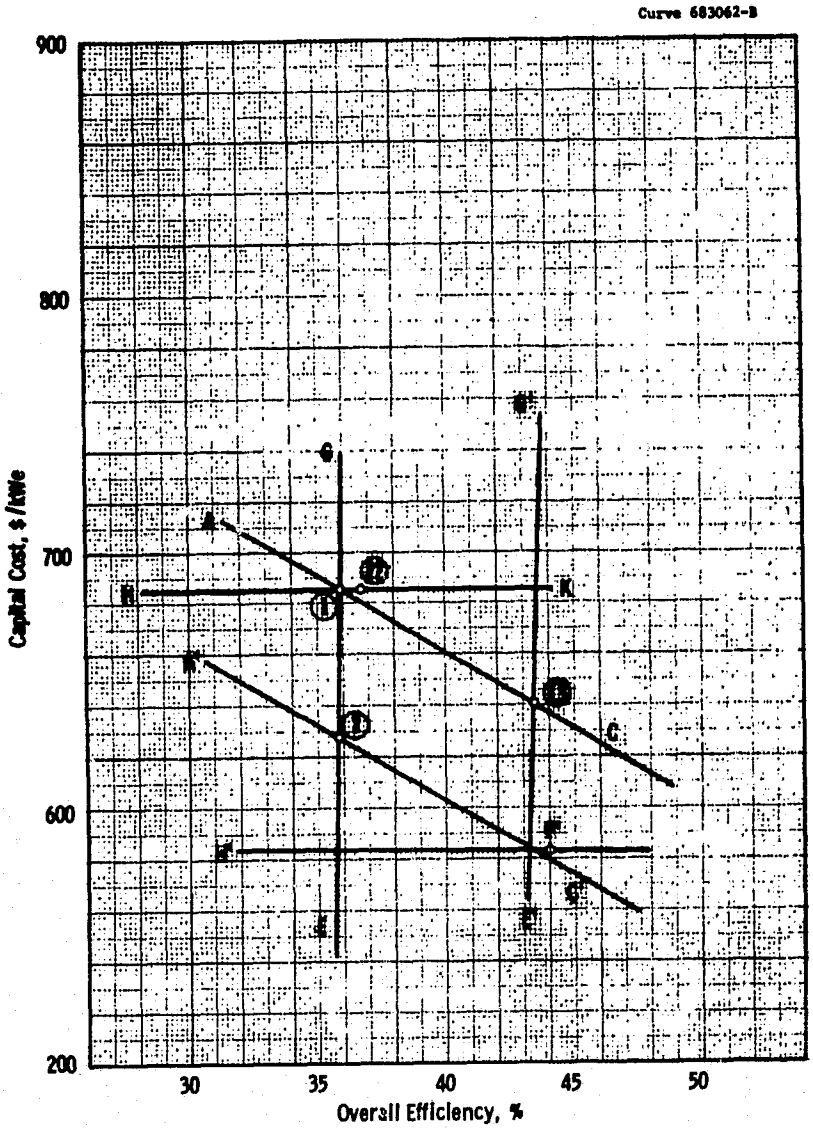

Fig. 8.24—Capital cost vs overall efficiency for fluidized bed boiler plants

Curve 683063-B

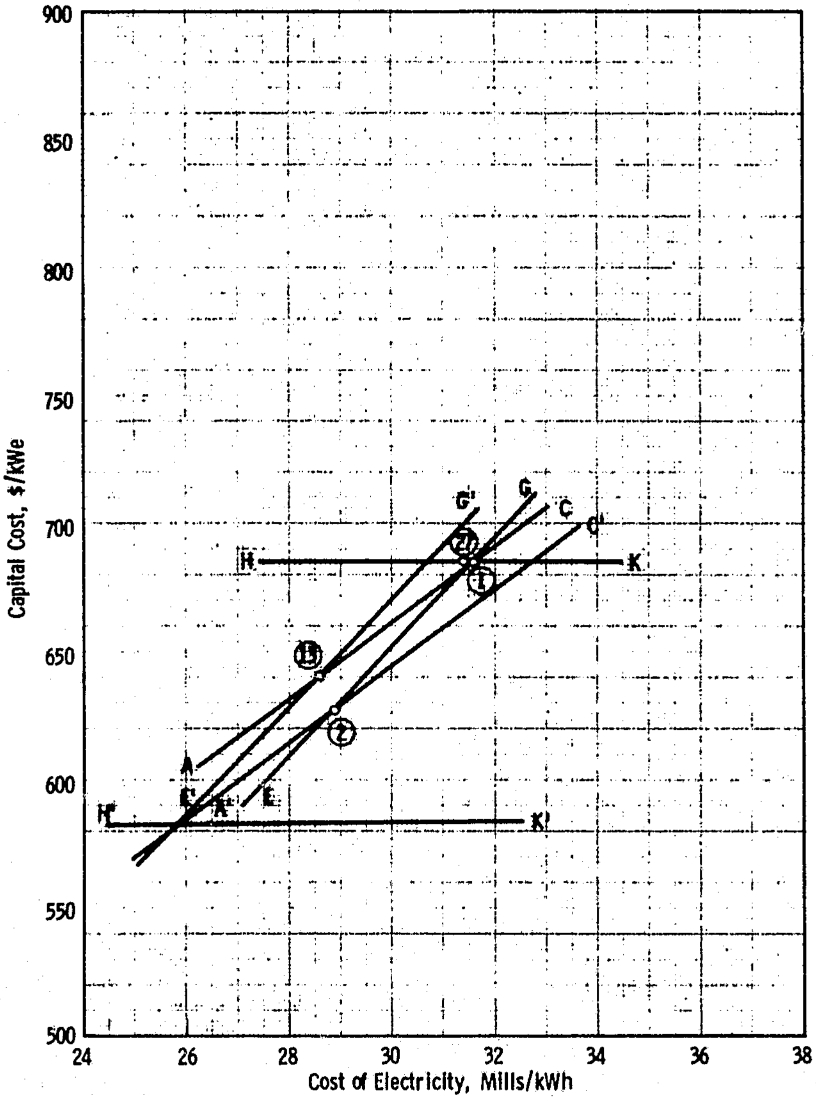

Fig. 8.25—Capital cost is cost of electricity for fluidized bed boiler plant

E'G' is drawn through the bituminous coal plant with a gas feedwater heater and intersects line A'C' at Point B' to account for the reduced overall efficiency due to subbituminous coal. Point B' on Figures 8.24 and 8.25 determines a new plant burning subbituminous coal with 1255°K (1800°F) gas turbine inlet temperature, a gas-heated feedwater heater, a nonreheat 24.132 MPa (3500 psi) gauge steam turbine. Point B' on Figure 8.24 has an efficiency of 44.0% and a $583/kWe capital cost.

The line HK has been drawn through Point 1 [a 24.132 MPa (3500 psi) gauge nonreheat steam turbine cycle] and Point 27 [a 24.132 MPa (3500 psi) gauge reheat steam turbine] in Figures 8.24 and 8.25 to define the rate of change of energy efficiency versus capital cost for reheat versus nonreheat steam cycles. Parallel line H'K' was drawn through the new subbituminous burning plant with a gas feedwater heater point B' on both figures. Assuming the same 0.8 percentage point efficiency improvement of reheat (Point 27) over nonreheat (Point 1), a subbituminous coal plant F' with reheat steam is determined along line H'K' for 44.0% overall energy efficiency on Figure 8.24. The new optimum plant F', with a 24.132 MPa (3500 psi) gauge steam turbine, 1255°K (1800°F) gas turbine inlet temperature, burning subbituminous coal, has a capital cost of $583/kWe at 44.0% overall energy efficiency on Figure 8.24.

If we follow the same procedure on Figure 8.25, the new optimum plant F' with a capital cost of $583/kWe along line H'K' has a cost of electricity of 7.17 mills/MJ (25.8 mills/kWh). Optimum plant F' has a 3.8% improvement in overall energy efficiency and an approximately 13% reduction in the cost of electricity over the preliminary optimum plant estimates.

On the basis of conventional power plant data, an additional cost reduction is possible. Redesign of the pressurized fluidized bed units to allow for greater utilization of shop fabrication instead of field erection could reduce construction time by three to six months. Such a reduction in time would significantly reduce the interest costs during construction.

Component modularization not only reduces construction time, but also facilitates and lends itself to the concept of partial plant operation. With the independent loop arrangement described briefly in Subsection 8.5.1.11 the availability of the liquid-metal vapor Rankine topping cycle plant can be significantly improved. Aside from loss of feedwater flow in the single steam turbine or loss of fuel from the coal-handling system, each of the four loops may operate independently of the other three.

The concept of power unit modules also provides for extension of the capital investment period. Rather than build a 1200 MWe plant all at once and tie up investing capital, one 300 MWe basic power unit is installed with full-size fuel handling and part-load operating steam turbine. When the first basic power unit begins producing power, additional power units can be added as load demand increases. In this way investment capital is available for other uses.

Appendix A 8.3 contains a listing of the economic model of the direct cost accounts and the cost of electricity for the preliminary optimum plant cycle with potassium (Point 49) and Points 1 and 4.

8.7 Conclusions and Recommendations

The results of this study indicate that a liquid-metal vapor Rankine topping cycle plant offers desirable plant performance. Development of the full potential of a direct coal-fired liquid-metal vapor Rankine topping cycle requires the development of high-temperature materials, the liquid-metal turbine, and the fluidized bed boiler. Power plant efficiencies of 40 to 44% are obtainable, based on current liquid-metal vapor turbine technology.

The economic potential of the system is limited by high costs for power conversion and liquid-metal heat transfer and piping equipment. The lowest electrical costs determined were about 8.05 mills/MJ (29 mills/kWh). Further optimization studies could improve the plant design performance and, therefore, the cost of electricity. Extrapolations presented in Section 8.6, for example, imply costs more in the area of 7.17 mills/MJ (25.8 mills/kWh).

These results are adequate for a preliminary design and assessment of the relative effects of components and parameters on the system performance and costs. Further studies are required to optimize the plant configuration and parameters. Final conclusive performance and cost values can only be forthcoming upon completion of those studies.

Of all the systems considered, the costing factors of the metal vapor turbine are the most uncertain, due to the preliminary nature of the design, particularly at the high temperatures studied. The costing factors of the pressurized combustors are also uncertain, and are lacking for liquid-metal subsystems of both the combustor subsystems and liquid-metal subsystems. Extensive liquid-metal power system technology being developed will provide considerable data on the further development of the liquid-metal topping cycle.

The major limiting factors are suitable high-temperature materials and the uncertainties of high-temperature liquid-metal technology. Improved design and high-temperature metal technology would probably reduce the heat transfer and power conversion equipment costs, improving the attractiveness of the cycle.

The performance analysis of the 50 cases demonstrated that the combination of individually optimized components and parameters does not necessarily yield an optimum plant. The resulting cycle efficiencies could have been significantly improved by optimization of the combination of components and parameters investigated, without assuming advancement in the state of the art of the technologies involved. The analysis, however, did provide direction in selecting a new base case for further optimization. It also demonstrated that cycle efficiencies higher than conventional fossil-fired plants are attainable.

The economic analysis of the 50 cases demonstrated that high capital costs are generally required to obtain high cycle efficiencies; but it also provided direction in the selection of system configuration, operating parameters, and, in particular, fuel for a new base from which to continue plant optimization. For example, the extrapolations of Subsection 8.6.9 indicate ∿ 4% improvement in overall efficiency to 44.0% and a reduction in the cost of electricity of 13% to 7.17 mills/MJ (25.8 mills/kWh) over the preliminary optimum estimates. These improvements are the result of using Montana subbituminous coal instead of Illinois No. 6 and of raising the gas turbine inlet temperature to 1255°K (1800°F). The conclusions of Section 8.4 indicate that additional improvements in overall cycle efficiency may be obtained by combining the gas-heated feedwater heaters and economizers with recuperators at a compressor pressure ratio of 10 to 1 rather than 15 to 1. Further conclusions from Subsection 8.6.9 indicate significant reduction in the interest during construction by reducing construction time. Modularization of the pressurized fluidized beds could potentially reduce the construction period by three to six months. The utilization of modularized basic power units for part-load operation significantly improves the plant availability over the value assumed for this study. Modularized basic power units also provide for extension of the capital investment period, another potential cost reduction.

The recommended system configuration and parameters for Task II are listed in Table 8.30. The plant described is the recommended base case from which to continue the further optimization of the liquid-metal topping cycle. The values listed are the result of the economic and performance analysis described above.

An alternate liquid-metal vapor topping cycle is also recommended on Table 8.30. The final choice of working fluid cannot be made without further analysis. The performance and cost of electricity of the cesium topping cycle of Task I are suspect due to the uncertainties in the cesium property and thermodynamic data and to the preliminary nature of the cesium turbine design and performance. A more detailed study of cesium and, in particular, the cesium turbine is a prerequisite before final selection of the working fluid.

Table 8.30 - Recommended System Configuration and Parameters

	Base	Alternate
Power, MWe	1200	
Furnace	PFB	
Coal	Montana	
Working Fluid	Potassium	Cesium
Recuperator Effectiveness	0.7	
Gas-Heated Feedwater, Heater	Yes	
Gas-Heated Economizer	Yes	
Compressor Pressure Ratio	10	
Air Equivalence Ratio	1.2	
Gas Turbine Inlet Temp., °F	1800	
L.-M. Turbine Inlet Temp., °F	1400	
L.-M. Condenser-Steam Generator Temperature, °F	1100	
Steam Throttle Temperature, °F	1000	
Reheat Temperature, °F	1000	
Steam Throttle Pressure, psig	3500	
Condenser Back Pressure, in Hg abs	3.5	

Additional conclusions of the Task I parametric analysis are listed in Table 8.31. A list of recommendations applicable to Task II are found in Table 8.32.

The preliminary optimum cycle demonstrated a cycle overall efficiency of 42.4% for potassium and 42.9% for cesium at a cost of electricity of about 8.21 and 8.67 mills/MJ (29.6 and 31.2 mills/kWh), respectively. These are preliminary results. Additional optimization studies will show a significant increase in cycle efficiency and greatly improve the attractiveness of the cost of electricity. Final conclusions and judgements on the liquid-metal vapor topping cycle cannot be made until the completion of these additional studies.

Table 8.31 - Preliminary Conclusions

1. Pressurized fluidized bed plant is more efficient and more cost effective than pressurized furnace plant.
2. Subbituminous coal is the most cost effective in a pressurized fluidized bed.
3. A gas-heated feedwater provides the most significant improvement in plant efficiency.
4. A gas-heated economizer is cost effective.
5. Efficiency decreases as the air equivalence ratio increases above a minimum value of 1.2.
6. Increasing the liquid-metal vapor turbine inlet temperature beyond 1033°K (1400°F) is not economically justifiable.
7. Increasing steam temperature above 811°K (1000°F) is not cost effective for either reheat or nonreheat steam cycles.
8. A supercritical steam pressure of 24.132 MPa (3500 psi) gauge is more efficient and cost effective than is the subcritical steam of 16.547 MPa (2400 psi) gauge.
9. Variation of system parameters separately does not provide the optimum cycle when individual optimums are combined.
10. Cesium is almost competitive with potassium as the selection of the liquid-metal working fluid.
11. Varied separately and individually, plant efficiency improves for increased compressor pressure ratio in the range 5 to 15 to 1 and for decreasing gas turbine inlet temperature in the range 1255°K (1800°F) to 1144°K (1600°F). Recuperation in the combustor pressurizing subsystem is not economically justifiable. In proper combinations together, however, and with stack-gas regeneration, potential plant efficiencies are higher at the maximum gas turbine inlet temperature [1255°K (1800°F)] and at a compressor pressure ratio of 10 with recuperation than the maximum efficiency values obtained individually.

Table 8.32 - Preliminary Recommendations

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1. Provide a potassium boiler design with nucleation site promoters to protect the boiler tubes by reducing the high wall-temperature differences which occur during the vaporization of potassium.
2. Provide an ejector system on the condenser-steam generator to remove noncondensibles.
3. Provide liquid-metal vapor line sized to 40% full power vapor flow to by-pass the turbine and pass vapor directly to the condenser in the event of a loss of turbine event.
4. Provide a saturated liquid-metal by-pass line from the drum to the condenser as a means of reducing dissolute corrosion (10% flow).
5. Provide a liquid-metal hot trap in the above mentioned saturated liquid 10% flow by-pass line to remove oxygen in order to reduce corrosion.
6. Perform a feasibility study of jet pump or natural circulation to replace the recirculation pump.
7. Perform a feasibility study of the EM pump as a liquid-metal feed pump.
8. Study the liquid-metal component relative elevations to reduce pumping requirements.
9. Reevaluate recuperator effectiveness as a function of the compressor pressure ratio and the gas turbine inlet temperature.
10. Evaluate the gas turbine intercooling when recuperation is not feasible.
11. Reevaluate the gas feedwater heater and gas economizer effect on cycle.
12. Evaluate in detail the condenser-steam generator duplex-tube design with metallic bonds for liquid-metal/water reaction protection.

Table 8.32 continued

13. Evaluate the thermal stress on the water inlet side of the condenser-steam generator.

14. Perform a transient analysis study to determine the saturated liquid hold-up requirements of the liquid-metal drum.

15. Perform a transient analysis study to determine the dump-tank, vent-line, and rupture-disk criteria in the event of a liquid-metal/water reaction.

16. Perform a transient analysis of the boiler in liquid-metal/water reaction transient.

17. Analyze the liquid-metal turbine and condenser to mitigate damage in the event of steam tube rupture.

18. Perform detailed design studies of potassium and cesium turbines.

19. Provide protective partitions separating liquid-metal turbine generators and condensers in the event of a liquid-metal/water reaction.

20. Provide a scrubber system and flame suppressor on liquid-metal/water reaction vent lines.

21. Evaluate the use of 300 MWe basic power modules to extend the capital investment period and provide better availability.

22. Evaluate component modularization to reduce the time of construction.

8.8 References

8.1 J. D. Mangus, "Steam Generator and Turbine-Generator Cycle Selection for the Westinghouse Demonstration Plant," WARD-217, October 1971.

8.2 A. P. Fraas, "A Potassium-Steam Binary Vapor Cycle for Better Fuel Economy and Reduced Thermal Pollution," Journal of Engineering for Power, Trans. ASME, Vol., January 1973, pp. 53-62.

8.3 Private communication with J. Tackett of Stellite Division, Cabot Corporation.

8.4 L. R. Smith, M. R. Tek, and R. E. Balzhiser, "Pressure Drops and Void Fractions in Horizontal Two-Phase Flows of Potassium," AIChE Journal, 12, Vol. 12, January 1966, pp. 50-58.

8.5 R. J. Rossbach, E. Schnetzer, H. E. Nichols, and S. E. Eckard, "Performance of a Two-Stage, 200 HP Turbine in Wet Potassium Vapor," AIAA Specialists Conference on Rankine Space Power Systems, Vol. 1, CONF-651026, October 1965.

Appendix A 8.1

LIQUID-METAL RANKINE TOPPING CYCLE PARAMETRIC POINTS SYSTEM CONFIGURATION AND PARAMETRIC STATE POINTS

CASE NO. 1

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	* * * * * * EFFICIENCIES * * * * *	
FURNACE	PR.FLD.BED			L.M.SYSTEM	.097
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.380
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.370
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.57

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.382	1400.000	15.200		188.000
2 L.M.CONDENSER		1100.000	2.400	5.856	
3 L.M.FEED PUMP	5277.000 GPM	1100.000	33.900		.363
4 L.M.RECIRC PUMP	13574.000 GPM	1280.000	20.610		.173
5 L.M.BOILER INLET		1280.000		6.600	
6 STEAM TURBINE THROTTLE	6.774	1000.000	3515.000		720.500
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.396	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.320	59.000	14.690		
12 GAS TURBINE INLET	11.216	1600.000			291.500
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		344.000			
16 AS RECEIVED COAL	499.400T/HR			10.775	

CASE NO. 2

				* * * * * * EFFICIENCIES * * * * *	
POWER OUTPUT(MWE)	1200	GAS TURBINE INLET			
FURNACE	PR.FLD.BED	TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
COAL	SUBBIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.280
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.374
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.365
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.34

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.113	1400.000	15.200		181.000
2 L.M.CONDENSER		1100.000	2.400	5.643	
3 L.M.FEED PUMP	5085.000 GPM	1100.000	31.720		.324
4 L.M.RECIRC PUMP	13080.000 GPM	1280.000	20.230		.155
5 L.M.BOILER INLET		1280.000		6.360	
6 STEAM TURBINE THROTTLE	6.527	1000.000	3515.000		694.400
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.273	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.427	59.000	14.690		
12 GAS TURBINE INLET	13.318	1600.000			324.400
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		851.000			
16 AS RECEIVED COAL	611.600T/HR			10.940	

CASE NO. 3

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	****** EFFICIENCIES *****	
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	L.M.SYSTEM	.097
COAL	LIG	GAS FEEDWATER HEATER	NO	PRESSURIZING SUBSYSTEM	.285
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	GROSS PLANT	.366
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET PLANT	.356
AIR EQUIVALENCE RATIO	1.2			NET POWER OUTPUT(MWE)	1169.48

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	6.872	1400.000	15.200		175.000
2 L.M.CONDENSER		1100.000	2.400	5.452	
3 L.M.FEED PUMP	4913.000 GPM	1100.000	29.770		.293
4 L.M.RECIRC PUMP	12637.000 GPM	1280.000	19.890		.140
5 L.M.BOILER INLET		1280.000		6.144	
6 STEAM TURBINE THROTTLE	6.306	1000.000	3515.000		670.900
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.162	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.676	59.000	14.690		
12 GAS TURBINE INLET	12.086	1800.000			354.000
13 GAS ECON.GAS INLET.		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		855.000			
16 AS RECEIVED COAL	812.600T/HR			11.198	

CASE NO. 4

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.263
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.[illegible] 1	GROSS PLANT	.365
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.356
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.88
AIR EQUIVALENCE RATIO	1.2				

(The last two columns are printed under the heading: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.327	1400.000	15.200		186.500
2 L.M.CONDENSER		1100.000	2.400	5.813	
3 L.M.FEED PUMP	5245.000 GPM	1100.000	33.590		.356
4 L.M.RECIRC PUMP	13491.000 GPM	1280.000	20.550		.170
5 L.M.BOILER INLET		1280.000		6.551	
6 STEAM TURBINE THROTTLE	6.724	1000.000	3515.000		715.300
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.372	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.056	59.000	14.690		
12 GAS TURBINE INLET	10.960	1800.000			298.600
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		857.000			
16 AS RECEIVED COAL	520.000T/HR			11.220	

CASE NO. [illegible]

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.276
COAL	SUBBIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.[illegible] 1	GROSS PLANT	.378
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.369
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.39
AIR EQUIVALENCE RATIO	1.2				

* * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.337	1400.000	15.200		186.800
2 L.M.CONDENSER		1100.000	2.400	5.821	
3 L.M.FEED PUMP	5245.000 GPM	1100.000	33.590		.356
4 L.M.RECIRC PUMP	13491.000 GPM	1280.000	20.550		.170
5 L.M.BOILER INLET		1280.000		6.560	
6 STEAM TURBINE THROTTLE	6.733	1000.000	3515.000		716.[illegible]
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.376	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.950	59.000	14.690		
12 GAS TURBINE INLET	10.865	1800.000			296.800
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		357.000			
16 AS RECEIVED COAL	604.600T/HR			10.815	

CASE NO. 6

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET		* * * * * * EFFICIENCIES * * * * *	
FURNACE	PR.FURNACE	TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
COAL	LIG	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.281
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.383
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.373
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.39

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.353	1400.000	15.200		187.300
2 L.M.CONDENSER		1100.000	2.400	5.833	
3 L.M.FEED PUMP	5245.000 GPM	1100.000	33.590		.356
4 L.M.RECIRC PUMP	13491.000 GPM	1280.000	20.550		.178
5 L.M.BOILER INLET		1280.000		6.575	
6 STEAM TURBINE THROTTLE	6.747	1000.000	3515.000		717.800
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.383	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.826	59.000	14.690		
12 GAS TURBINE INLET	10.809	1800.000			294.800
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		858.000			
16 AS RECEIVED COAL	776.100T/HR			10.695	

CASE NO. 7

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.272
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.385
RECUPERATOR EFFECTIVENESS	.7	L.M.FEEDHEATER	NO	NET PLANT	.375
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.36
AIR EQUIVALENCE RATIO	1.2				

(Right-hand block heading: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.463	1400.000	15.200		190.000
2 L.M.CONDENSER		1100.000	2.400	5.920	
3 L.M.FEED PUMP	5337.000 GPM	1100.000	34.700		.375
4 L.M.RECIRC PUMP	13730.000 GPM	1280.000	20.740		.179
5 L.M.BOILER INLET		1280.000		6.673	
6 STEAM TURBINE THROTTLE	6.848	1000.000	3515.000		728.600
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.434	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.197	59.000	14.690		
12 GAS TURBINE INLET	11.082	1800.000			281.300
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		601.000			
16 AS RECEIVED COAL	493.400T/HR			10.645	

CASE NO. 8

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.274
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.385
RECUPERATOR EFFECTIVENESS	.8	L.M.FEEDHEATER	NO	NET PLANT	.376
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.35
AIR EQUIVALENCE RATIO	1.2				

(* * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.469	1400.000	15.200		190.200
2 L.M.CONDENSER		1100.000	2.400	5.925	
3 L.M.FEED PUMP	5337.000 GPM	1100.000	34.700		.375
4 L.M.RECIRC PUMP	13730.000 GPM	1280.000	20.740		.179
5 L.M.BOILER INLET		1280.000		6.678	
6 STEAM TURBINE THROTTLE	6.854	1000.000	3515.000		729.100
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.437	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.172	59.000	14.690		
12 GAS TURBINE INLET	11.054	1800.000			250.600
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		794.000			
16 AS RECEIVED COAL	492.200T/HR			10.620	

CASE NO. 9

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.265
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.368
RECUPERATOR EFFECTIVENESS	.7	L.M.FEEDHEATER	NO	NET PLANT	.359
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.38
AIR EQUIVALENCE RATIO	1.2				

****** EFFICIENCIES *****

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.399	1400.000	15.200		188.400
2 L.M.CONDENSER		1100.000	2.400	5.869	
3 L.M.FEED PUMP	5291.000 GPM	1100.000	34.140		.365
4 L.M.RECIRC PUMP	13610.000 GPM	1280.000	20.640		.175
5 L.M.BOILER INLET		1280.000		6.615	
6 STEAM TURBINE THROTTLE	6.789	1000.000	3515.000		722.300
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.404	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.973	59.000	14.690		
12 GAS TURBINE INLET	10.870	1800.000			289.200
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		327.000			
16 AS RECEIVED COAL	515.300T/HR			11.118	

CASE NO. 10

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.369
RECUPERATOR EFFECTIVENESS	.8	L.M.FEEDHEATER	NO	NET PLANT	.360
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.38
AIR EQUIVALENCE RATIO	1.2				

(Last two columns: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.403	1400.000	15.200		188.500
2 L.M.CONDENSER		1100.000	2.400	5.873	
3 L.M.FEED PUMP	5291.000 GPM	1100.000	34.140		.365
4 L.M.RECIRC PUMP	13610.000 GPM	1280.000	20.640		.175
5 L.M.BOILER INLET		1280.000		6.619	
6 STEAM TURBINE THROTTLE	6.793	1000.000	3515.000		722.700
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.406	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.953	59.000	14.690		
12 GAS TURBINE INLET	10.848	1800.000			288.700
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		821.000			
16 AS RECEIVED COAL	514.200T/HR			11.094	

CASE NO. 11

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	1 1	GROSS PLANT	.380
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.370
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.68
AIR EQUIVALENCE RATIO	1.2				

(Right-hand block headed: ****** EFFICIENCIES *****)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.382	1400.000	15.200		188.000
2 L.M.CONDENSER		1100.000	2.400	5.856	
3 L.M.FEED PUMP	5277.000 GPM	1100.000	31.240		.331
4 L.M.RECIRC PUMP	-0.000 GPM	1100.000	-0.000		-0.000
5 L.M.BOILER INLET		1100.000		6.600	
6 STEAM TURBINE THROTTLE	6.774	1000.000	3515.000		720.700
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.396	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.321	59.000	14.690		
12 GAS TURBINE INLET	11.217	1800.000			291.300
13 GAS ECON.GAS INLET.		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	499.200T/HR			10.775	

CASE NO. 12

				* * * * * * EFFICIENCIES * * * * *	
POWER OUTPUT(MWE)	1200	GAS TURBINE INLET			
FURNACE	PR.FURNACE	TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.263
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	1 1	GROSS PLANT	.365
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.356
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.58

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.323	1400.000	15.200		186.500
2 L.M.CONDENSER		1100.000	2.400	5.809	
3 L.M.FEED PUMP	5235.000 GPM	1100.000	31.040		.327
4 L.M.RECIRC PUMP	-0.000 GPM	1100.000	-0.000		-0.000
5 L.M.BOILER INLET		1100.000		6.548	
6 STEAM TURBINE THROTTLE	6.720	1000.000	3515.000		714.900
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.369	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.052	59.000	14.690		
12 GAS TURBINE INLET	10.956	1800.000			298.500
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		857.000			
16 AS RECEIVED COAL	519.400T/HR			11.207	

CASE NO. 13

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET			
FURNACE	PR.FLD.BED	TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.265
WORKING FLUID	K	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.440
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.457
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.445
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.70

The last two columns above are headed: * * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	6.140	1400.000	15.200		156.400
2 L.M.CONDENSER		1100.000	2.400	5.871	
3 L.M.FEED PUMP	4389.000 GPM	1100.000	24.250		.209
4 L.M.RECIRC PUMP	11290.000 GPM	1280.000	18.950		.100
5 L.M.BOILER INLET		1280.000		5.490	
6 STEAM TURBINE THROTTLE	5.214	1000.000	3515.000		802.800
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.487	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	8.584	59.000	14.690		
12 GAS TURBINE INLET	9.329	1800.000			240.800
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		352.000		1.356	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	415.400T/HR			8.963	

8-120

CASE NO. 14

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO
COAL	BIT	GAS FEEDWATER HEATER	YES
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0
AIR EQUIVALENCE RATIO	1.2		

* * * * * * EFFICIENCIES * * * * *	
L.M.SYSTEM	.097
PRESSURIZING SUBSYSTEM	.263
STEAM CYCLE	.440
GROSS PLANT	.425
NET PLANT	.415
NET POWER OUTPUT(MWE)	1169.71

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	6.053	1400.000	15.200		154.100
2 L.M.CONDENSER		1100.000	2.400	5.802	
3 L.M.FEED PUMP	4327.000 GPM	1100.000	23.630		.200
4 L.M.RECIRC PUMP	11130.000 GPM	1280.000	18.840		.096
5 L.M.BOILER INLET		1280.000		5.411	
6 STEAM TURBINE THROTTLE	5.194	1000.000	3515.000		799.600
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.474	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	8.307	59.000	14.690		
12 GAS TURBINE INLET	9.054	1800.000			246.300
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		865.000		1.401	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	429.200T/HR			9.630	

CASE NO. 15

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1500.0		
FURNACE	PR.FLD.BED	GAS ECONOMIZER	YES		
COAL	BIT	GAS FEEDWATER HEATER	NO		
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1		
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO		
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0		
AIR EQUIVALENCE RATIO	1.2				

* * * * * * EFFICIENCIES * * * * *	
L.M.SYSTEM	.097
PRESSURIZING SUBSYSTEM	.265
STEAM CYCLE	.432
GROSS PLANT	.419
NET PLANT	.408
NET POWER OUTPUT(MWE)	1168.93

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	6.697	1400.000	15.200		170.500
2 L.M.CONDENSER		1100.000	2.400	5.313	
3 L.M.FEED PUMP	5639.000 GPM	1100.000	28.400		.271
4 L.M.RECIRC PUMP	12315.000 GPM	1280.000	19.660		.129
5 L.M.BOILER INLET		1280.000		5.987	
6 STEAM TURBINE THROTTLE	6.417	1000.000	3515.000		766.100
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.466	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.363	59.000	14.690		
12 GAS TURBINE INLET	10.176	1800.000			262.700
13 GAS ECON.GAS INLET.		852.000		.739	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	453.100T/HR			9.776	

CASE NO. 16

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FURNACE	GAS ECONOMIZER	YES	PRESSURIZING SUBSYSTEM	.263
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.432
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.404
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.394
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.62
AIR EQUIVALENCE RATIO	1.2				

(Last two columns: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	6.622	1400.000	15.200		168.600
2 L.M.CONDENSER		1100.000	2.400	5.254	
3 L.M.FEED PUMP	4734.000 GPM	1100.000	27.810		.262
4 L.M.RECIRC PUMP	12177.000 GPM	1280.000	19.560		.125
5 L.M.BOILER INLET		1280.000		5.921	
6 STEAM TURBINE THROTTLE	6.576	1000.000	3515.000		762.000
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.419	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.090	59.000	14.690		
12 GAS TURBINE INLET	9.907	1800.000			269.400
13 GAS ECON.GAS INLET.		865.000		.766	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	469.700T/HR			10.134	

CASE NO. 17

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.201
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.336
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.327
COMPRESSOR PRESSURE RATIO	5	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.50

(Last two columns: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.265	1400.000	15.200		185.000
2 L.M.CONDENSER		1100.000	2.400	5.763	
3 L.M.FEED PUMP	5194.000 GPM	1100.000	32.980		.346
4 L.M.RECIRC PUMP	13360.000 GPM	1280.000	20.440		.165
5 L.M.BOILER INLET		1280.008		6.495	
6 STEAM TURBINE THROTTLE	6.657	1000.000	3515.000		709.300
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.343	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	11.682	59.000	14.690		
12 GAS TURBINE INLET	12.696	1800.000			305.700
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		1150.000			
16 AS RECEIVED COAL	565.300T/HR			12.197	

CASE NO. 18

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.252
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.368
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.359
COMPRESSOR PRESSURE RATIO	10	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.50
AIR EQUIVALENCE RATIO	1.2				

(Right columns: ****** EFFICIENCIES *****)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.224	1400.000	15.200		184.000
2 L.M.CONDENSER		1100.000	2.400	5.731	
3 L.M.FEED PUMP	5150.000 GPM	1100.000	32.980		.346
4 L.M.RECIRC PUMP	13360.000 GPM	1280.000	20.440		.165
5 L.M.BOILER INLET		1280.008		6.459	
6 STEAM TURBINE THROTTLE	6.629	1000.000	3515.000		705.300
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.324	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.662	59.000	14.690		
12 GAS TURBINE INLET	11.588	1800.000			310.700
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		949.000			
16 AS RECEIVED COAL	515.900T/HR			11.131	

CASE NO. 19

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	* * * * * * EFFICIENCIES * * * * *	
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	L.M.SYSTEM	.097
COAL	BIT	GAS FEEDWATER HEATER	NO	PRESSURIZING SUBSYSTEM	.125
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	GROSS PLANT	.212
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET PLANT	.207
AIR EQUIVALENCE RATIO	2.0			NET POWER OUTPUT(MWE)	1169.61

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	5.789	1400.000	15.200		147.400
2 L.M.CONDENSER		1100.000	2.400	4.593	
3 L.M.FEED PUMP	4138.000 GPM	1100.000	21.810		.175
4 L.M.RECIRC PUMP	10645.000 GPM	1280.000	20.350		.129
5 L.M.BOILER INLET		1280.000		5.176	
6 STEAM TURBINE THROTTLE	5.313	1000.000	3515.000		565.200
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	2.664	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	18.485	59.000	14.690		
12 GAS TURBINE INLET	20.089	1800.000			487.300
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		817.000			
16 AS RECEIVED COAL	894.400T/HR			19.297	

CASE NO. 20

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	****** EFFICIENCIES *****	
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	L.M.SYSTEM	.097
COAL	BIT	GAS FEEDWATER HEATER	NO	PRESSURIZING SUBSYSTEM	.096
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	GROSS PLANT	.127
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET PLANT	.124
AIR EQUIVALENCE RATIO	3.0			NET POWER OUTPUT(MWE)	1169.77

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	3.421	1400.000	15.200		87.400
2 L.M.CONDENSER		1100.000	2.400	2.722	
3 L.M.FEED PUMP	2446.000 GPM	1100.000	32.440		.160
4 L.M.RECIRC PUMP	6290.000 GPM	1280.000	20.350		.076
5 L.M.BOILER INLET		1280.000		3.068	
6 STEAM TURBINE THROTTLE	3.148	1000.000	3515.000		334.900
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	1.579	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	30.770	59.000	14.690		
12 GAS TURBINE INLET	33.441	1800.000			777.700
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		805.000			
16 AS RECEIVED COAL	1488.900T/HR			32.125	

CASE NO. 21

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	*** * * * * * EFFICIENCIES * * * * ***	
FURNACE	PR.FLD.BED			L.M.SYSTEM	.097
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.291
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.403
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.393
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.27

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.883	1400.000	15.200		200.700
2 L.M.CONDENSER		1100.000	2.400	6.253	
3 L.M.FEED PUMP	5635.000 GPM	1100.000	38.410		.442
4 L.M.RECIRC PUMP	14496.000 GPM	1280.000	21.370		.211
5 L.M.BOILER INLET		1280.000		7.048	
6 STEAM TURBINE THROTTLE	7.234	1000.000	3515.000		769.500
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.627	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.737	59.000	14.690		
12 GAS TURBINE INLET	10.583	1600.000			229.700
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		726.000			
16 AS RECEIVED COAL	471.100T/HR			10.165	

CASE NO. 22

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1700.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.284
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.394
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.385
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.32
AIR EQUIVALENCE RATIO	1.2				

* * * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.639	1400.000	15.200		194.500
2 L.M.CONDENSER		1100.000	2.400	6.060	
3 L.M.FEED PUMP	5460.000 GPM	1100.000	36.220		.402
4 L.M.RECIRC PUMP	14047.000 GPM	1280.000	21.000		.192
5 L.M.BOILER INLET		1280.000		6.830	
6 STEAM TURBINE THROTTLE	7.010	1000.000	3515.000		745.800
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.515	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.941	59.000	14.690		
12 GAS TURBINE INLET	10.804	1700.000			259.600
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		790.000			
16 AS RECEIVED COAL	481.000T/HR			10.378	

CASE NO. 23

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.098
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.381
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.371
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.42
AIR EQUIVALENCE RATIO	1.2				

(Efficiencies in the last two columns: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.486	1500.000	24.700		190.600
2 L.M.CONDENSER		1200.000	4.800	5.840	
3 L.M.FEED PUMP	5444.000 GPM	1200.000	43.600		.460
4 L.M.RECIRC PUMP	14028.000 GPM	1380.000	29.330		.141
5 L.M.BOILER INLET		1380.000		6.593	
6 STEAM TURBINE THROTTLE	6.755	1000.000	3515.000		718.600
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.387	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.310	59.000	14.690		
12 GAS TURBINE INLET	11.205	1800.000			290.800
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	498.900T/HR			10.757	

CASE NO. 24

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.100
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.381
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.372
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.27
AIR EQUIVALENCE RATIO	1.2				

(Last two columns: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.583	1600.000	38.200		193.100
2 L.M.CONDENSER		1300.000	8.800	5.824	
3 L.M.FEED PUMP	5608.000 GPM	1300.000	58.880		.611
4 L.M.RECIRC PUMP	14446.000 GPM	1480.000	42.590		.138
5 L.M.BOILER INLET		1480.000		6.577	
6 STEAM TURBINE THROTTLE	6.737	1000.000	3515.000		716.700
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.378	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.285	59.000	14.690		
12 GAS TURBINE INLET	11.178	1800.000			290.200
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		344.000			
16 AS RECEIVED COAL	497.700T/HR			10.738	

CASE NO. 25

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	*** * * * * * EFFICIENCIES * * * * ***	
FURNACE	PR.FLD.BED			L.M.SYSTEM	.098
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.430
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.386
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.376
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.73

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.381	1500.000	24.700		186.000
2 L.M.CONDENSER		1200.000	4.800	5.756	
3 L.M.FEED PUMP	5368.000 GPM	1200.000	42.520		.440
4 L.M.RECIRC PUMP	13831.000 GPM	1380.000	29.200		.135
5 L.M.BOILER INLET		1380.000		6.500	
6 STEAM TURBINE THROTTLE	6.140	1100.000	3515.000		725.400
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.282	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.165	59.000	14.690		
12 GAS TURBINE INLET	11.047	1800.000			286.900
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	491.900T/HR			10.613	

CASE NO. 26

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.100
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.443
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.394
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.384
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.34
AIR EQUIVALENCE RATIO	1.2				

****** EFFICIENCIES *****

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.343	1600.000	38.200		187.000
2 L.M.CONDENSER		1300.000	8.800	5.640	
3 L.M.FEED PUMP	5431.000 GPM	1300.000	55.770		.555
4 L.M.RECIRC PUMP	13988.000 GPM	1480.000	42.320		.125
5 L.M.BOILER INLET		1480.000		6.369	
6 STEAM TURBINE THROTTLE	5.607	1200.000	3515.000		732.000
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.141	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.959	59.000	14.690		
12 GAS TURBINE INLET	10.823	1800.000			281.000
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	481.900T/HR			10.397	

CASE NO. 27

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.435
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.388
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.378
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1169.41
AIR EQUIVALENCE RATIO	1.2				

(Right-hand block headed: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.227	1400.000	15.200		184.000
2 L.M.CONDENSER		1100.000	2.400	5.733	
3 L.M.FEED PUMP	3166.000 GPM	1100.000	32.660		.340
4 L.M.RECIRC PUMP	13290.000 GPM	1280.000	20.390		.163
5 L.M.BOILER INLET		1280.000		6.461	
6 STEAM TURBINE THROTTLE	5.269	1000.000	3515.000		730.700
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.239	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.104	59.000	14.690		
12 GAS TURBINE INLET	10.981	1800.000			285.200
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	488.900T/HR			10.549	

CASE NO. 28

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.098
FURNACE	PR.FLO.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.449
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.396
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.386
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1169.48
AIR EQUIVALENCE RATIO	1.2				

(* * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.194	1500.000	24.700		183.000
2 L.M.CONDENSER		1200.000	4.800	5.612	
3 L.M.FEED PUMP	5236.000 GPM	1200.000	40.630		.408
4 L.M.RECIRC PUMP	13492.000 GPM	1300.000	28.980		.125
5 L.M.BOILER INLET		1380.000		6.336	
6 STEAM TURBINE THROTTLE	4.807	1100.000	3515.000		737.400
7 STEAM REHEAT		1100.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.095	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.907	59.000	14.690		
12 GAS TURBINE INLET	10.767	1800.000			279.600
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	479.400T/HR			10.343	

CASE NO. 29

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	* * * * * * EFFICIENCIES * * * * *	
FURNACE	PR.FLD.BED			L.M.SYSTEM	.180
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.462
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.404
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.394
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1169.39

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.155	1600.000	38.200		182.200
2 L.M.CONDENSER		1300.000	8.800	5.49	
3 L.M.FEED PUMP	3292.000 GPM	1300.000	53.400		.514
4 L.M.RECIRC PUMP	13631.000 GPM	1480.000	42.110		.116
5 L.M.BOILER INLET		1480.000		6.206	
6 STEAM TURBINE THROTTLE	4.430	1200.000	3515.000		743.900
7 STEAM REHEAT		1200.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	2.950	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	9.705	59.000	14.690		
12 GAS TURBINE INLET	10.547	1800.000			273.900
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		644.000			
16 AS RECEIVED COAL	469.600T/HR			10.132	

CASE NO. 30

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.290
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.410
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.374
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.365
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.45
AIR EQUIVALENCE RATIO	1.2				

(Right-hand columns headed: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.490	1400.000	15.200		190.700
2 L.M.CONDENSER		1100.000	2.400	5.942	
3 L.M.FEED PUMP	5354.000 GPM	1100.000	34.910		.379
4 L.M.RECIRC PUMP	13773.000 GPM	1280.000	20.770		.181
5 L.M.BOILER INLET		1280.000		6.696	
6 STEAM TURBINE THROTTLE	6.338	1000.000	2415.000		713.800
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.506	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	10.471	59.000	14.690		
12 GAS TURBINE INLET	11.380	1800.000			295.500
13 GAS ECON.GAS INLET		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	506.700T/HR			10.933	

CASE NO. 31

				****** EFFICIENCIES *****	
POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.098
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.420
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.380
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.371
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.60
AIR EQUIVALENCE RATIO	1.2				

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.466	1500.000	24.700		190.600
2 L.M.CONDENSER		1200.000	4.800	5.840	
3 L.M.FEED PUMP	5444.000 GPM	1200.000	43.600		.460
4 L.M.RECIRC PUMP	14028.000 GPM	1380.000	29.330		.141
5 L.M.BOILER INLET		1380.000		6.594	
6 STEAM TURBINE THROTTLE	5.824	1100.000	2415.000		718.600
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.387	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	10.311	59.000	14.690		
12 GAS TURBINE INLET	11.206	1800.000			290.990
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	498.900T/HR			10.764	

CASE NO. 32

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.100
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.430
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.387
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.377
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.40
AIR EQUIVALENCE RATIO	1.2				

(Last two columns: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.476	1600.000	38.200		190.400
2 L.M.CONDENSER		1300.000	8.800	5.740	
3 L.M.FEED PUMP	********** GPM	1300.000	57.490		.586
4 L.M.RECIRC PUMP	1,242.000 GPM	1480.000	42.470		.132
5 L.M.BOILER INLET		1480.000		6.485	
6 STEAM TURBINE THROTTLE	5.389	1200.000	2415.000		723.500
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.273	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	10.141	59.000	14.690		
12 GAS TURBINE INLET	11.021	1800.000			286.200
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	490.700T/HR			10.587	

CASE NO. 33

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0		
FURNACE	PP.FLC.350	GAS ECONOMIZER	NO	*** * * * * * EFFICIENCIES * * * * ***	
COAL	BIT	GAS FEEDWATER HEATER	NO	L.M.SYSTEM	.097
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	PRESSURIZING SUBSYSTEM	.267
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	STEAM CYCLE	.426
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	GROSS PLANT	.383
AIR EQUIVALENCE RATIO	1.2			NET PLANT	.374
				NET POWER OUTPUT(MWE)	1169.49

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.320	1400.000	15.200		186.400
2 L.M.CONDENSER		1100.000	2.400	5.807	
3 L.M.FEED PUMP	5233.000 GPM	1100.000	33.450		.354
4 L.M.RECIRC PUMP	13460.000 GPM	1280.000	20.520		.169
5 L.M.BOILER INLET		1280.000		6.544	
6 STEAM TURBINE THROTTLE	5.238	1000.000	2415.000		724.800
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.333	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	10.234	59.000	14.690		
12 GAS TURBINE INLET	11.122	1800.000			288.800
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		644.000			
16 AS RECEIVED COAL	495.200T/HR			10.684	

CASE NO. 34

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.098
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.436
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.389
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.380
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1169.75
AIR EQUIVALENCE RATIO	1.2				

* * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.316	1500.000	24.700		186.300
2 L.M.CONDENSER		1200.000	4.800	5.707	
3 L.M.FEED PUMP	5320.000 GPM	1200.000	41.850		.429
4 L.M.RECIRC PUMP	13709.000 GPM	1380.000	29.120		.131
5 L.M.BOILER INLET		1380.000		6.444	
6 STEAM TURBINE THROTTLE	4.840	1100.000	2415.000		729.600
7 STEAM REHEAT		1100.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.219	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	10.076	59.000	14.690		
12 GAS TURBINE INLET	10.950	1800.000			284.400
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	487.500T/HR			10.518	

CASE NO. 35

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.100
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.452
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.399
RECUPERATOR EFFECTIVENESS	0.0	L.P.FEEDHEATER	NO	NET PLANT	.369
COMPRESSOR PRESSURE RATIO	13	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1169.36
AIR EQUIVALENCE RATIO	1.2				

(Last two columns under heading: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.253	1600.000	38.200		184.700
2 L.M.CONDENSER		1300.000	8.800	5.570	
3 L.M.FEED PUMP	5365.000 GPM	1300.000	54.630		.535
4 L.M.RECIRC PUMP	13817.000 GPM	1480.000	32.220		.121
5 L.M.BOILER INLET		1480.000		6.291	
6 STEAM TURBINE THROTTLE	4.466	1200.000	2415.000		737.700
7 STEAM REHEAT		1200.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.052	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	9.837	59.000	14.690		
12 GAS TURBINE INLET	10.691	1800.000			277.600
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	476.000T/HR			10.270	

CASE NO. 36

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET		* * * * * * EFFICIENCIES * * * * *	
FURNACE	PR.FLD.BED	TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
COAL	BIT	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
WORKING FLUID	K	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.421
RECUPERATOR EFFECTIVENESS	0.0	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.380
COMPRESSOR PRESSURE RATIO	15	L.M.FEEDHEATER	NO	NET PLANT	.371
AIR EQUIVALENCE RATIO	1.2	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.38

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.371	1400.000	15.200		187.700
2 L.M.CONDENSER		1100.000	2.400	5.647	
3 L.M.FEED PUMP	5269.000 GPM	1100.000	33.880		.361
4 L.M.RECIRC PUMP	13554.000 GPM	1280.000	20.600		.173
5 L.M.BOILER INLET		1280.000		6.591	
6 STEAM TURBINE THROTTLE	6.237	1000.000	2415.000		721.300
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			2.000IN.HG	3.385	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	10.306	59.000	14.690		
12 GAS TURBINE INLET	11.201	1800.000			290.900
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	498.700T/HR			10.760	

CASE NO. 37

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.383
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.360
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.351
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1168.70
AIR EQUIVALENCE RATIO	1.2				

(* * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.790	1400.000	15.200		198.400
2 L.M.CONDENSER		1100.000	2.400	6.160	
3 L.M.FEED PUMP	5569.000 GPM	1100.000	37.560		.426
4 L.M.RECIRC PUMP	14325.000 GPM	1280.000	21.230		.204
5 L.M.BOILER INLET		1280.000		6.965	
6 STEAM TURBINE THROTTLE	6.591	1000.000	2415.000		693.500
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			9.000IN.HG	3.813	
9 FINAL FEEDWATER		530.000			
10 COND/SG WATER INLET		530.000			
11 COMPRESSOR INLET	10.892	59.000	14.690		
12 GAS TURBINE INLET	11.837	1800.000			307.400
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	527.000T/HR			11.370	

CASE NO. 38

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.037
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.207
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.432
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.386
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.377
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.50
AIR EQUIVALENCE RATIO	1.2				

* * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.258	1400.000	15.200		184.800
2 L.M.CONDENSER		1100.000	2.400	5.755	
3 L.M.FEED PUMP	5188.000 GPM	1100.000	32.930		.345
4 L.M.RECIRC PUMP	13346.000 GPM	1280.000	20.430		.165
5 L.M.BOILER INLET		1280.000		6.489	
6 STEAM TURBINE THROTTLE	6.660	1000.000	3515.000		728.800
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			2.000IN.HG	3.271	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.147	59.000	14.690		
12 GAS TURBINE INLET	11.028	1800.000			286.400
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		844.000			
16 AS RECEIVED COAL	491.000T/HR			10.594	

CASE NO. 39

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1800.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.267
COAL	BIT	GAS FEEDWATER HEATER	NO	STEAM CYCLE	.392
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.365
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.356
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	0	NET POWER OUTPUT(MWE)	1169.41
AIR EQUIVALENCE RATIO	1.2				

* * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	7.691	1400.000	15.200		195.800
2 L.M.CONDENSER		1100.000	2.400	6.101	
3 L.M.FEED PUMP	5498.000 GPM	1100.000	36.680		.410
4 L.M.RECIRC PUMP	14143.000 GPM	1280.000	21.090		.196
5 L.M.BOILER INLET		1280.000		6.876	
6 STEAM TURBINE THROTTLE	7.057	1000.000	3515.000		700.700
7 STEAM REHEAT		0.000	0.000		
8 ST.COND.BACK PRESS.			9.000IN.HG	3.709	
9 FINAL FEEDWATER		560.000			
10 COND/SG WATER INLET		560.000			
11 COMPRESSOR INLET	10.752	59.000	14.690		
12 GAS TURBINE INLET	11.685	1800.000			303.500
13 GAS ECON.GAS INLET.		0.000		0.000	
14 GAS FWH GAS INLET		0.000		0.000	
15 STACK GAS EXHAUST		644.000			
16 AS RECEIVED COAL	520.300T/HR			11.226	

CASE NO. 40

POWER OUTPUT(MWE)	600	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.256
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.446
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.435
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	584.80
AIR EQUIVALENCE RATIO	1.2				

(Right column heading: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	3.441	1400.000	15.200		87.630
2 L.M.CONDENSER		1100.000	2.400	2.730	
3 L.M.FEED PUMP	4920.000 GPM	1100.000	29.850		.147
4 L.M.RECIRC PUMP	12657.000 GPM	1280.000	19.910		.070
5 L.M.BOILER INLET		1280.000		3.077	
6 STEAM TURBINE THROTTLE	2.685	1000.000	3515.000		413.330
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	1.847	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	4.250	59.000	14.690		
12 GAS TURBINE INLET	4.632	1600.000			99.050
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		852.000		.527	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	212.750T/HR			4.590	

CASE NO. 41

POWER OUTPUT(MWE)	900	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.256
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.446
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.435
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	877.21

(Right-hand group headed: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	5.163	1400.000	15.200		131.450
2 L.M.CONDENSER		1100.000	2.400	4.095	
3 L.M.FEED PUMP	4920.000 GPM	1100.000	29.850		.220
4 L.M.RECIRC PUMP	12657.000 GPM	1280.000	19.910		.105
5 L.M.BOILER INLET		1280.000		4.615	
6 STEAM TURBINE THROTTLE	4.027	1000.000	3515.000		620.000
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	2.771	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	6.375	59.000	14.690		
12 GAS TURBINE INLET	6.948	1600.000			148.580
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		852.000		.792	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	319.130T/HR			6.885	

CASE NO. 42

POWER OUTPUT(MWE)	1500	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FLU.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.256
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.446
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.435
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1462.01

* * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	8.604	1400.000	15.200		219.090
2 L.M.CONDENSER		1100.000	2.400	6.82[illegible]	
3 L.M.FEED PUMP	4920.000 GPM	1100.000	29.850		.367
4 L.M.RECIRC PUMP	12657.000 GPM	1280.000	19.910		.176
5 L.M.BOILER INLET		1280.000		7.692	
6 STEAM TURBINE THROTTLE	6.711	1000.000	3515.000		1033.330
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	4.618	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	10.625	59.000	14.690		
12 GAS TURBINE INLET	11.579	1600.000			247.625
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		852.000		1.320	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	531.880T/HR			11.476	

CASE NO. 43

POWER OUTPUT(MWE)	600	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	***** EFFICIENCIES *****	
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	L.M.SYSTEM	.097
COAL	BIT	GAS FEEDWATER HEATER	YES	PRESSURIZING SUBSYSTEM	.262
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	STEAM CYCLE	.433
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	GROSS PLANT	.416
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET PLANT	.406
AIR EQUIVALENCE RATIO	1.2			NET POWER OUTPUT(MWE)	584.61

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	3.384	1400.000	15.200		86.160
2 L.M.CONDENSER		1100.000	2.400	2.664	
3 L.M.FEED PUMP	4337.000 GPM	1100.000	28.930		.140
4 L.M.RECIRC PUMP	12444.000 GPM	1280.000	19.750		.067
5 L.M.BOILER INLET		1280.000		3.025	
6 STEAM TURBINE THROTTLE	2.666	1000.000	3515.000		410.400
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	1.834	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	4.079	59.000	14.690		
12 GAS TURBINE INLET	4.458	1600.000			103.450
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		865.000		.550	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	218.020T/HR			4.922	

CASE NO. 44

POWER OUTPUT(MWE)	900	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.262
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.416
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.406
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	877.22
AIR EQUIVALENCE RATIO	1.2				

(Right-hand columns: * * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	5.075	1400.000	15.200		129.240
2 L.M.CONDENSER		1100.000	2.400	4.026	
3 L.M.FEED PUMP	4837.000 GPM	1100.000	28.930		.210
4 L.M.RECIRC PUMP	12444.000 GPM	1280.000	19.750		.100
5 L.M.BOILER INLET		1280.000		4.538	
6 STEAM TURBINE THROTTLE	3.998	1000.000	3515.000		615.600
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	2.751	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	6.119	59.000	14.690		
12 GAS TURBINE INLET	6.687	1600.000			155.180
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		865.000		.826	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	327.020T/HR			7.383	

CASE NO. 45

POWER OUTPUT(MWE)	1500	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	* * * * * * EFFICIENCIES * * * * *	
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	L.M.SYSTEM	.097
COAL	BIT	GAS FEEDWATER HEATER	YES	PRESSURIZING SUBSYSTEM	.262
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	STEAM CYCLE	.433
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	GROSS PLANT	.416
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET PLANT	.406
AIR EQUIVALENCE RATIO	1.2			NET POWER OUTPUT(MWE)	1462.03

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	8.459	1400.000	15.200		215.400
2 L.M.CONDENSER		1100.000	2.400	6.710	
3 L.M.FEED PUMP	4637.000 GPM	1100.000	28.930		.349
4 L.M.RECIRC PUMP	12444.000 GPM	1280.000	19.750		.167
5 L.M.BOILER INLET		1280.000		7.563	
6 STEAM TURBINE THROTTLE	6.664	1000.000	3515.000		1026.000
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	4.585	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	10.198	59.000	14.690		
12 GAS TURBINE INLET	11.145	1600.000			258.630
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		665.000		1.376	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	545.040T/HR			12.305	

CASE NO. 46

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.136
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.256
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	CS	L.M.CIRCULATION RATIO	2.F 1	GROSS PLANT	.452
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.441
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1168.92
AIR EQUIVALENCE RATIO	1.2				

******* EFFICIENCIES *****

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	27.263	1400.000	15.290		194.11
2 L.M.CONDENSER		1100.000	2.400	5.349	
3 L.M.FEED PUMP	8786.000 GPM	1100.000	56.570		1.108
4 L.M.RECIRC PUMP	22707.000 GPM	1280.000	21.130		.400
5 L.M.BOILER INLET		1280.000		6.066	
6 STEAM TURBINE THROTTLE	5.265	1000.000	3515.000		810.64
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.623	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	8.378	59.000	14.690		
12 GAS TURBINE INLET	9.130	1600.000			195.25
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		852.000		1.040	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	419.395T/HR			9.048	

CASE NO. 47

POWER OUTPUT(MWE)	600	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.106
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.256
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	CS	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.452
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.441
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	584.47
AIR EQUIVALENCE RATIO	1.2				

(* * * * * * EFFICIENCIES * * * * *)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	13.632	1400.000	15.200		97.06
2 L.M.CONDENSER		1100.000	2.400	2.674	
3 L.M.FEED PUMP	8786.000 GPM	1100.000	56.570		.554
4 L.M.RECIRC PUMP	22707.000 GPM	1280.000	21.130		.200
5 L.M.BOILER INLET		1280.000		3.033	
6 STEAM TURBINE THROTTLE	2.633	1000.000	3515.000		420.790
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	1.812	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	4.189	59.000	14.690		
12 GAS TURBINE INLET	4.551	1600.000			97.63
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		852.000		.520	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	209.70T/HR			4.524	

CASE NO. 46

POWER OUTPUT(MWE)	1500	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	*** * * * * * EFFICIENCIES * * * * ***	
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	L.M.SYSTEM	.136
COAL	BIT	GAS FEEDWATER HEATER	YES	PRESSURIZING SUBSYSTEM	.256
WORKING FLUID	CS	L.M.CIRCULATION RATIO	2.5 1	STEAM CYCLE	.433
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	GROSS PLANT	.452
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET PLANT	.441
AIR EQUIVALENCE RATIO	1.2			NET POWER OUTPUT(MWE)	1461.15

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	34.080	1400.000	15.200		242.640
2 L.M.CONDENSER		1100.000	2.400	6.686	
3 L.M.FEED PUMP	8786.000 GPM	1100.000	56.570		1.385
4 L.M.RECIRC PUMP	22707.000 GPM	1280.000	21.130		.500
5 L.M.BOILER INLET		1280.000		7.583	
6 STEAM TURBINE THROTTLE	6.581	1000.000	3515.000		1013.300
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	4.529	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	10.473	59.000	14.690		
12 GAS TURBINE INLET	11.379	1600.000			244.060
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		852.000		1.301	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	524.250T/HR			11.311	

CASE NO. 49

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FLD.BED	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.256
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.446
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.435
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1169.61
AIR EQUIVALENCE RATIO	1.2				

* * * * * * EFFICIENCIES * * * * *

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	6.883	1400.000	15.200		175.270
2 L.M.CONDENSER		1100.000	2.400	5.460	
3 L.M.FEED PUMP	4920.000 GPM	1100.000	29.850		.294
4 L.M.RECIRC PUMP	12657.000 GPM	1280.000	19.910		.141
5 L.M.BOILER INLET		1280.000		6.154	
6 STEAM TURBINE THROTTLE	5.369	1000.000	3515.000		826.660
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.694	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	8.500	59.000	14.690		
12 GAS TURBINE INLET	9.263	1600.000			198.100
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		852.000		1.055	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	425.500T/HR			9.161	

CASE NO. 50

POWER OUTPUT(MWE)	1200	GAS TURBINE INLET TEMPERATURE (DEG-F)	1600.0	L.M.SYSTEM	.097
FURNACE	PR.FURNACE	GAS ECONOMIZER	NO	PRESSURIZING SUBSYSTEM	.262
COAL	BIT	GAS FEEDWATER HEATER	YES	STEAM CYCLE	.433
WORKING FLUID	K	L.M.CIRCULATION RATIO	2.5 1	GROSS PLANT	.416
RECUPERATOR EFFECTIVENESS	0.0	L.M.FEEDHEATER	NO	NET PLANT	.406
COMPRESSOR PRESSURE RATIO	15	STAGES OF STEAM REHEAT	1	NET POWER OUTPUT(MWE)	1169.62
AIR EQUIVALENCE RATIO	1.2				

(The last two columns are headed "* * * * * * EFFICIENCIES * * * * *".)

**** STATE POINTS ****	TOTAL FLOW 10E06 LBM/HR	TEMPERATURE DEG-F	PRESSURE PSIA	THERMAL LOAD 10E09 BTU/HR	POWER OUTPUT MWE
1 L.M.TURBINE INLET	6.767	1400.000	15.200		172.320
2 L.M.CONDENSER		1100.000	2.400	5.368	
3 L.M.FEED PUMP	4837.000 GPM	1100.000	26.930		.279
4 L.M.RECIRC PUMP	12444.000 GPM	1280.000	19.750		.133
5 L.M.BOILER INLET		1280.000		6.050	
6 STEAM TURBINE THROTTLE	5.331	1000.000	3515.000		820.800
7 STEAM REHEAT		1000.000	600.000		
8 ST.COND.BACK PRESS.			3.500IN.HG	3.668	
9 FINAL FEEDWATER		492.000			
10 COND/SG WATER INLET		492.000			
11 COMPRESSOR INLET	8.158	59.000	14.690		
12 GAS TURBINE INLET	8.936	1600.000			206.900
13 GAS ECON.GAS INLET,		0.000		0.000	
14 GAS FWH GAS INLET		865.000		1.101	
15 STACK GAS EXHAUST		290.000			
16 AS RECEIVED COAL	436.030T/HR			9.844	

Appendix A 8.2

LIQUID-METAL RANKINE TOPPING CYCLE PARAMETRIC POINTS SUMMARY SHEETS

Table A 8.2.1

RANKINE METAL VAPOR TOPPING-STEAM CYCLE SUMMARY PLANT RESULTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.359	.358	.348	.348	.367	.371	.364	.364
OVERALL ENERGY EFF	.359	.358	.348	.350	.381	.388	.364	.364
CAP COST MILLION $	776.079	721.355	741.956	925.075	872.115	881.708	790.658	811.147
CAPITAL COST,$/KWE	684.626	627.370	649.436	809.230	748.654	758.307	697.187	715.261
COE CAPITAL	21.643	19.833	20.530	25.582	23.667	23.972	22.040	22.611
COE FUEL	8.081	8.095	8.325	8.334	7.905	7.817	7.973	7.973
COE OP & MAIN	1.863	.930	.968	1.964	.981	.998	1.847	1.847
COST OF ELECTRIC	31.585	28.858	29.823	35.879	32.552	32.786	31.859	32.430
EST TIME OF CONST	6.500	6.500	6.500	5.500	6.500	6.500	6.500	6.500

PARAMETRIC POINT	9	10	11	12	13	14	15	16
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.351	.352	.359	.348	.434	.407	.397	.386
OVERALL ENERGY EFF	.353	.354	.359	.350	.434	.409	.397	.388
CAP COST MILLION $	944.610	959.520	767.408	917.654	730.096	869.674	762.690	900.675
CAPITAL COST,$/KWE	825.290	838.250	676.977	801.866	639.964	757.021	670.467	784.835
COE CAPITAL	26.089	26.499	21.401	25.349	20.231	23.931	21.195	24.812
COE FUEL	8.264	8.241	8.061	8.334	6.677	7.130	7.303	7.509
COE OP & MAIN	1.953	1.949	1.863	1.963	1.647	1.770	1.744	1.830
COST OF ELECTRIC	36.306	36.689	31.345	35.646	28.554	32.831	30.242	34.151
EST TIME OF CONST	6.500	6.500	6.500	6.500	6.500	6.500	6.500	6.500

PARAMETRIC POINT	17	18	19	20	21	22	23	24
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.316	.347	.194	.111	.381	.373	.360	.360
OVERALL ENERGY EFF	.316	.347	.194	.111	.381	.373	.360	.360
CAP COST MILLION $	859.552	787.353	915.664	1178.917	775.139	784.569	781.671	823.214
CAPITAL COST,$/KWE	762.292	695.367	833.057	1126.112	682.735	691.433	689.465	726.089
COE CAPITAL	24.098	21.982	26.335	35.599	21.583	21.858	21.796	22.953
COE FUEL	9.188	8.354	14.939	26.182	7.608	7.786	8.059	8.059
COE OP & MAIN	2.034	1.904	2.316	4.644	1.793	1.819	1.859	1.853
COST OF ELECTRIC	35.320	32.240	44.190	66.425	30.984	31.463	31.713	32.871
EST TIME OF CONST	6.500	6.500	6.500	5.500	6.500	6.500	6.500	6.500

PARAMETRIC POINT	25	26	27	28	29	30	31	32
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.365	.373	.367	.375	.383	.353	.359	.366
OVERALL ENERGY EFF	.365	.373	.367	.375	.383	.353	.359	.366
CAP COST MILLION $	799.084	855.857	777.107	820.626	895.424	772.847	795.443	851.515
CAPITAL COST,$/KWE	704.339	753.484	684.791	722.283	788.096	682.438	701.695	750.455
COE CAPITAL	22.266	23.819	21.648	22.833	24.913	21.573	22.182	23.724
COE FUEL	7.949	7.778	7.906	7.737	7.575	8.219	8.081	7.927
COE OP & MAIN	1.841	1.812	1.833	1.805	1.778	1.882	1.859	1.834
COST OF ELECTRIC	32.055	33.410	31.387	32.375	34.267	31.674	32.122	33.485
EST TIME OF CONST	5.500	6.500	6.500	6.500	6.500	6.500	6.500	6.500

PARAMETRIC POINT	33	34	35	36	37	38	39	40
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.362	.368	.378	.360	.336	.366	.341	.423
OVERALL ENERGY EFF	.362	.368	.378	.360	.336	.366	.341	.423
CAP COST MILLION $	783.820	917.674	893.169	769.340	813.396	767.740	811.559	330.500
CAPITAL COST,$/KWE	691.168	720.565	785.939	675.854	725.225	673.957	722.912	685.501
COE CAPITAL	21.849	22.779	24.842	21.365	22.925	21.305	22.853	21.673
COE FUEL	8.014	7.886	7.676	8.047	8.621	7.917	8.495	6.852
COE OP & MAIN	1.849	1.828	1.792	1.805	1.894	1.788	1.878	1.677
COST OF ELECTRIC	31.712	32.493	34.310	31.218	33.442	31.010	33.226	30.202
EST TIME OF CONST	6.500	6.500	6.500	6.500	6.500	6.500	6.500	5.757

Table A 8.2.1 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE SUMMARY PLANT RESULTS

PARAMETRIC POINT	41	42	43	44	45	46	47	48
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.423	.423	.398	.398	.398	.429	.429	.429
OVERALL ENERGY EFF	.423	.423	.400	.400	.400	.429	.429	.429
CAP COST MILLION $	573.661	965.793	443.079	554.363	1106.025	823.205	421.321	1044.248
CAPITAL COST,$/KWE	671.515	678.296	772.263	760.438	771.160	722.160	739.208	732.816
COE CAPITAL	21.228	21.442	24.414	24.039	24.378	22.829	23.368	23.166
COE FUEL	6.852	6.852	7.293	7.293	7.293	6.756	6.756	6.756
COE OP & MAIN	1.678	1.678	1.800	1.800	1.800	1.661	1.661	1.661
COST OF ELECTRIC	29.758	29.972	33.506	33.132	33.471	31.246	31.785	31.583
EST TIME OF CONST	6.181	6.759	5.757	6.181	6.759	6.500	5.757	6.753

PARAMETRIC POINT	49	50	51	52	53	54	55	56
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.424	.398	.000	.000	.000	.000	.000	.000
OVERALL ENERGY EFF	.424	.400	.000	.000	.000	.000	.000	.000
CAP COST MILLION $	760.293	892.804	.000	.000	.000	.000	.000	.000
CAPITAL COST,$/KWE	666.942	769.360	.000	.000	.000	.000	.000	.000
COE CAPITAL	21.084	24.321	.000	.000	.000	.000	.000	.000
COE FUEL	6.847	7.293	.000	.000	.000	.000	.000	.000
COE OP & MAIN	1.672	1.800	.000	.000	.000	.000	.000	.000
COST OF ELECTRIC	29.602	33.413	.000	.000	.000	.000	.000	.000
EST TIME OF CONST	6.500	6.500	.000	.000	.000	.000	.000	.000

Table A 8.2.2

RANKINE METAL VAPOR TOPPING-STEAM CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT		1	2	3	4	5	6	7	8
	TOTAL CAPITAL COST	,M$	776.08	721.36	741.96	926.07	872.11	881.71	790.66	811.15
P	LIQ MET VAPOR GENERATORS	,M$	59.648	53.504	57.344	17.600	17.600	17.600	59.648	62.208
L	LIQ MET TURBINE	,M$	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000
A	STEAM TURB-GEN & FEED STG	,M$	21.200	21.160	21.110	21.200	21.200	21.200	21.235	21.235
N	MET VAP COND-STEAM GEN	,M$	9.340	8.960	8.860	9.340	9.340	9.340	9.340	9.340
T	LIQ MET CIRC & PROCESS SYS	,M$	27.178	27.063	26.448	26.048	26.048	26.048	27.183	27.183
	GAS TURB PUMPUP-REC-PIPING	,M$	37.600	37.160	38.560	36.400	36.120	35.800	36.800	36.800
	LIQ MET AUX ELEC EQUIP.	,M$	2.750	2.750	2.750	2.750	2.750	2.750	2.750	2.750
R	TOT MAJOR COMPONENT COST	,M$	181.716	174.597	179.072	137.338	137.058	136.738	180.956	185.516
E	TOT MAJOR COMPONENT COST	,$/KWE	160.303	151.849	156.742	120.010	117.655	117.601	159.564	161.822
S	BALANCE OF PLANT COST	,$/KWE	77.592	69.030	71.515	158.247	142.430	145.577	82.649	86.357
U	SITE LABOR	,$/KWE	86.652	77.398	80.392	104.470	94.797	96.202	88.275	90.781
L	TOTAL DIRECT COST	,$/KWE	324.547	298.276	308.650	382.727	354.882	359.379	330.488	338.960
T	INDIRECT COSTS	,$/KWE	44.193	39.473	41.000	53.280	48.346	49.063	45.020	46.298
	PROF & OWNER COSTS	,$/KWE	25.964	23.862	24.692	30.618	28.391	28.750	26.439	27.117
B	CONTINGENCY COST	,$/KWE	30.832	28.336	29.322	36.359	33.714	34.141	31.396	32.201
R	ESCALATION COST	,$/KWE	117.152	107.354	111.130	138.474	128.108	129.760	119.301	122.394
E	INT DURING CONSTRUCTION	,$/KWE	141.939	130.068	134.643	167.772	155.213	157.215	144.543	148.290
A	TOTAL CAPITALIZATION	,$/KWE	684.626	627.370	649.436	809.230	748.654	758.307	697.187	715.261
K	COST OF ELEC-CAPITAL	,MILLS/KWE	21.643	19.833	20.530	25.582	23.667	23.972	22.040	22.611
D	COST OF ELEC-FUEL	,MILLS/KWE	8.081	8.095	8.325	8.334	7.905	7.817	7.973	7.973
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.863	.930	.968	1.964	.981	.998	1.847	1.847
W	TOTAL COST OF ELEC	,MILLS/KWE	31.586	28.858	29.823	35.879	32.552	32.786	31.859	32.430
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	38.191	34.919	36.094	43.665	39.764	40.089	38.582	39.325
	COE 0.8 CAP. FACTOR	,MILLS/KWE	27.454	25.065	25.899	31.008	28.040	28.217	27.652	28.116
	COE 1.2XCAP. COST	,MILLS/KWE	35.915	32.824	33.929	40.995	37.286	37.581	35.267	36.953
	COE 1.2XFUEL COST	,MILLS/KWE	33.203	30.477	31.488	37.546	34.134	34.350	33.454	34.025
	COE (CONTINGENCY=0)	,MILLS/KWE	30.018	27.417	28.332	34.030	30.938	31.050	30.262	30.793
	COE (ESCALATION=0)	,MILLS/KWE	27.058	24.708	25.527	30.526	27.600	27.770	27.247	27.699

	PARAMETRIC POINT		9	10	11	12	13	14	15	16
	TOTAL CAPITAL COST	,M$	944.61	959.52	767.41	917.65	730.10	869.67	762.69	900.68
P	LIQ MET VAPOR GENERATORS	,M$	17.600	17.600	59.648	17.600	51.456	17.600	54.784	17.600
L	LIQ MET TURBINE	,M$	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000
A	STEAM TURB-GEN & FEED STG	,M$	21.210	21.210	21.200	21.200	26.180	26.000	26.405	26.285
N	MET VAP COND-STEAM GEN	,M$	9.340	9.340	9.340	9.340	8.860	9.340	8.860	9.040
T	LIQ MET CIRC & PROCESS SYS	,M$	26.153	26.158	23.320	22.300	26.163	25.143	26.433	25.408
	GAS TURB PUMPUP-REC-PIPING	,M$	36.120	36.120	37.600	36.400	32.400	32.800	39.900	39.380
	LIQ MET AUX ELEC EQUIP	,M$	2.750	2.750	2.750	2.750	2.750	2.750	2.750	2.750
R	TOT MAJOR COMPONENT COST	,M$	137.173	137.178	177.858	133.590	171.809	137.633	183.132	144.463
E	TOT MAJOR COMPONENT COST	,$/KWE	119.846	119.841	156.899	116.734	150.599	119.805	160.988	125.891
S	BALANCE OF PLANT COST	,$/KWE	164.261	168.962	77.593	158.243	71.915	141.640	71.892	144.662
U	SITE LABOR	,$/KWE	106.315	107.821	86.204	104.041	80.903	96.935	84.926	100.862
L	TOTAL DIRECT COST	,$/KWE	390.422	396.624	320.696	379.018	303.417	358.380	317.807	371.415
T	INDIRECT COSTS	,$/KWE	54.221	54.989	43.964	53.061	41.261	49.437	43.312	51.440
	PROF & OWNER COSTS	,$/KWE	31.234	31.730	25.656	30.321	24.273	28.670	25.425	29.713
B	CONTINGENCY COST	,$/KWE	37.090	37.679	30.466	36.007	28.825	34.046	30.192	35.284
R	ESCALATION COST	,$/KWE	141.222	143.439	115.843	137.214	109.509	129.540	114.729	134.308
E	INT DURING CONSTRUCTION	,$/KWE	171.102	173.789	140.353	166.245	132.679	156.948	139.003	162.725
A	TOTAL CAPITALIZATION	,$/KWE	825.290	838.250	676.977	801.866	639.964	757.021	670.467	784.885
K	COST OF ELEC-CAPITAL	,MILLS/KWE	26.089	26.499	21.401	25.349	20.231	23.931	21.195	24.812
D	COST OF ELEC-FUEL	,MILLS/KWE	8.264	8.241	8.081	8.334	6.677	7.130	7.303	7.509
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.953	1.949	1.863	1.963	1.647	1.770	1.744	1.830
W	TOTAL COST OF ELEC	,MILLS/KWE	36.306	36.689	31.345	35.646	28.554	32.831	30.242	34.151
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	44.245	44.750	37.876	43.362	34.735	40.121	36.712	41.706
	COE 0.8 CAP. FACTOR	,MILLS/KWE	31.340	31.646	27.257	30.818	24.686	28.269	26.193	29.424
	COE 1.2XCAP. COST	,MILLS/KWE	41.524	41.989	35.625	40.716	32.600	37.617	34.481	39.113
	COE 1.2XFUEL COST	,MILLS/KWE	37.959	38.338	32.961	37.313	29.890	34.257	31.702	35.653
	COE (CONTINGENCY=0)	,MILLS/KWE	34.420	34.773	29.795	33.815	27.088	31.099	28.706	32.356
	COE (ESCALATION=0)	,MILLS/KWE	30.897	31.145	26.867	30.342	24.321	27.823	25.807	28.959

Table A 8.2.2 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT		17	18	19	20	21	22	23	24
	TOTAL CAPITAL COST	,M$	859.55	787.35	915.66	1178.92	775.14	784.57	781.67	823.21
P	LIQ MET VAPOR GENERATORS	,M$	82.432	64.000	63.488	36.016	60.544	62.336	61.184	72.192
L	LIQ MET TURBINE	,M$	24.000	24.000	24.000	12.000	24.000	24.000	24.000	24.000
A	STEAM TURB-GEN & FEED STG	,M$	21.190	21.190	20.890	20.405	21.310	21.260	21.200	21.200
N	MET VAP COND-STEAM GEN	,M$	9.340	9.340	7.320	4.160	10.000	9.620	9.340	9.340
T	LIQ MET CIRC & PROCESS SYS	,M$	27.068	27.068	26.023	25.088	27.608	27.448	27.448	29.348
	GAS TURB PUMPUP-REC-PIPING	,M$	36.000	34.800	68.800	110.400	34.240	35.600	37.600	37.200
	LIQ MET AUX ELEC EQUIP	,M$	2.750	2.750	2.750	2.750	2.750	2.750	2.750	2.750
R	TOT MAJOR COMPONENT COST	,M$	202.780	183.148	213.271	260.819	180.452	183.014	183.522	196.030
E	TOT MAJOR COMPONENT COST	,$/KWE	179.835	161.751	194.031	249.137	158.940	161.288	161.874	172.902
S	BALANCE OF PLANT COST	,$/KWE	80.444	78.213	96.833	132.697	77.462	77.778	77.520	77.507
U	SITE LABOR	,$/KWE	99.692	89.172	104.468	149.134	86.995	88.346	87.392	93.221
L	TOTAL DIRECT COST	,$/KWE	359.972	329.136	395.332	530.968	323.398	327.413	326.786	343.630
T	INDIRECT COSTS	,$/KWE	50.843	45.478	53.279	76.058	44.368	45.057	44.570	47.543
	PROF & OWNER COSTS	,$/KWE	28.798	26.331	31.627	42.477	25.872	26.193	26.143	27.490
B	CONTINGENCY COST	,$/KWE	34.197	31.268	37.557	50.442	30.723	31.104	31.045	32.645
R	ESCALATION COST	,$/KWE	130.442	118.990	142.551	192.698	116.828	118.316	117.980	124.247
E	INT DURING CONSTRUCTION	,$/KWE	158.041	144.166	172.712	233.469	141.547	143.350	142.942	150.535
A	TOTAL CAPITALIZATION	,$/KWE	762.292	695.367	833.057	1126.112	682.735	691.433	589.465	726.089
K	COST OF ELEC-CAPITAL	,MILLS/KWE	24.098	21.982	26.335	35.599	21.583	21.858	21.796	22.953
D	COST OF ELEC-FUEL	,MILLS/KWE	9.188	8.354	14.939	26.182	7.608	7.786	8.059	8.059
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	2.034	1.904	2.916	4.644	1.793	1.819	1.859	1.859
W	TOTAL COST OF ELEC	,MILLS/KWE	35.320	32.240	44.190	66.425	30.984	31.463	31.713	32.871
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	42.660	38.946	52.201	77.216	37.570	38.132	38.363	39.868
	COE 0.8 CAP. FACTOR	,MILLS/KWE	30.727	28.044	39.177	59.675	26.863	27.290	27.552	28.492
	COE 1.2XCAP. COST	,MILLS/KWE	40.139	36.637	49.457	73.545	35.301	35.835	36.073	37.462
	COE 1.2XFUEL COST	,MILLS/KWE	37.157	33.911	47.177	71.661	32.506	33.020	33.325	34.483
	COE (CONTINGENCY=0)	,MILLS/KWE	33.580	30.650	42.280	63.859	29.422	29.831	30.135	31.211
	COE (ESCALATION=0)	,MILLS/KWE	30.277	27.641	38.679	58.976	26.468	26.889	27.153	28.068

	PARAMETRIC POINT		25	26	27	28	29	30	31	32
	TOTAL CAPITAL COST	,M$	799.08	855.86	777.11	820.63	896.42	772.85	795.45	851.52
P	LIQ MET VAPOR GENERATORS	,M$	60.032	70.656	58.624	59.392	69.376	60.058	61.184	71.424
L	LIQ MET TURBINE	,M$	24.000	24.000	24.000	24.000	24.000	24.000	24.000	24.000
A	STEAM TURB-GEN & FEED STG	,M$	26.400	31.500	21.230	31.550	41.860	21.600	26.700	31.900
N	MET VAP COND-STEAM GEN	,M$	10.460	10.180	11.020	11.860	12.420	7.940	8.220	8.220
T	LIQ MET CIRC & PROCESS SYS	,M$	27.438	29.153	27.068	27.248	29.048	27.188	27.368	29.268
	GAS TURB PUMPUP-REC-PIPING	,M$	36.400	36.120	36.400	36.120	35.600	38.000	37.600	36.800
	LIQ MET AUX ELEC EQUIP	,M$	2.750	2.750	2.750	2.750	2.750	2.750	2.750	2.750
R	TOT MAJOR COMPONENT COST	,M$	187.480	204.359	181.092	192.920	215.054	181.536	187.822	204.362
E	TOT MAJOR COMPONENT COST	,$/KWE	165.251	179.915	159.579	169.801	189.066	160.299	165.685	180.108
S	BALANCE OF PLANT COST	,$/KWE	80.359	81.709	77.968	82.742	85.601	76.832	78.984	80.258
U	SITE LABOR	,$/KWE	88.544	95.506	86.955	90.329	99.178	86.378	88.225	95.266
L	TOTAL DIRECT COST	,$/KWE	334.154	357.129	324.503	342.872	373.845	323.509	332.894	355.632
T	INDIRECT COSTS	,$/KWE	45.158	48.708	44.347	46.068	50.581	44.053	44.995	48.585
	PROF & OWNER COSTS	,$/KWE	26.732	28.570	25.960	27.430	29.908	25.881	26.631	28.451
B	CONTINGENCY COST	,$/KWE	31.745	33.927	30.828	32.573	35.515	30.733	31.625	33.785
R	ESCALATION COST	,$/KWE	120.525	123.935	117.180	123.595	134.857	116.777	120.072	128.416
E	INT DURING CONSTRUCTION	,$/KWE	146.026	156.215	141.973	149.746	163.390	141.485	145.478	155.587
A	TOTAL CAPITALIZATION	,$/KWE	704.339	753.484	684.731	722.283	788.096	682.438	701.695	750.455
K	COST OF ELEC-CAPITAL	,MILLS/KWE	22.266	23.819	21.648	22.833	24.913	21.573	22.182	23.724
D	COST OF ELEC-FUEL	,MILLS/KWE	7.949	7.778	7.906	7.737	7.575	8.219	8.081	7.927
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.841	1.812	1.833	1.805	1.778	1.882	1.859	1.834
W	TOTAL COST OF ELEC	,MILLS/KWE	32.055	33.410	31.387	32.375	34.267	31.674	32.122	33.485
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	38.846	40.667	37.993	39.336	41.852	38.258	38.888	40.713
	COE 0.8 CAP. FACTOR	,MILLS/KWE	27.806	28.869	27.254	28.019	29.521	27.555	27.889	28.962
	COE 1.2XCAP. COST	,MILLS/KWE	36.508	38.174	35.717	36.942	39.249	35.969	36.559	38.229
	COE 1.2XFUEL COST	,MILLS/KWE	33.645	34.965	32.963	33.923	35.782	33.318	33.738	35.070
	COE (CONTINGENCY=0)	,MILLS/KWE	30.441	31.684	29.819	30.719	32.460	30.111	30.514	31.766
	COE (ESCALATION=0)	,MILLS/KWE	27.396	28.426	26.857	27.597	29.054	27.160	27.481	28.521

Table A 8.2.2 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT		33	34	35	36	37	38	39	40
	TOTAL CAPITAL COST	,M$	783.82	817.67	893.17	769.34	813.40	767.74	811.56	390.50
P	LIQ MET VAPOR GENERATORS	,M$	60.723	60.058	69.988	59.648	62.208	58.624	61.[illegible]84	30.336
L	LIQ MET TURBINE	,M$	24.000	24.000	24.000	24.000	24.000	24.000	24.000	12.000
A	STEAM TURB-GEN & FEED STG	,M$	21.600	31.920	42.250	22.900	24.350	22.535	23.970	12.805
N	MET VAP COND-STEAM GEN	,M$	11.020	10.740	10.740	8.780	9.160	9.340	9.620	5.242
T	LIQ MET CIRC & PROCESS SYS	,M$	27.083	27.263	29.048	27.078	27.598	27.0[illegible]8	27.453	17.624
	GAS TURB PUMPUP-REC-PIPING	,M$	37.200	36.800	36.000	37.600	38.800	36.[illegible]00	38.400	15.200
	LIQ MET AUX ELEC EQUIP	,M$	2.750	2.750	2.750	2.750	2.750	2.750	2.750	1.375
R	TOT MAJOR COMPONENT COST	,M$	184.376	193.531	214.676	182.756	188.866	1[illegible]1.117	187.377	94.581
E	TOT MAJOR COMPONENT COST	,$/KWE	162.582	170.547	188.879	160.549	168.393	[illegible]58.993	166.910	166.057
S	BALANCE OF PLANT COST	,$/KWE	76.966	81.147	84.399	74.258	87.558	75.183	88.245	84.968
U	SITE LABOR	,$/KWE	87.912	90.287	99.314	85.570	89.037	85.310	88.739	93.541
L	TOTAL DIRECT COST	,$/KWE	327.461	341.981	372.592	320.377	344.[illegible]89	319.486	343.894	344.566
T	INDIRECT COSTS	,$/KWE	44.835	46.046	50.650	43.641	45.409	43.508	45.257	47.706
	PROF & OWNER COSTS	,$/KWE	26.197	27.358	29.807	25.630	27.599	25.559	27.512	27.565
B	CONTINGENCY COST	,$/KWE	31.109	32.488	35.396	30.436	32.779	30.351	32.670	30.175
R	ESCALATION COST	,$/KWE	118.271	123.301	134.471	115.651	124.099	115.326	123.703	107.987
E	INT DURING CONSTRUCTION	,$/KWE	143.295	149.390	162.922	140.120	150.356	139.727	149.876	127.602
A	TOTAL CAPITALIZATION	,$/KWE	691.168	720.565	785.839	675.854	725.225	673.957	722.912	685.601
K	COST OF ELEC-CAPITAL	,MILLS/KWE	21.849	22.773	24.842	21.365	22.926	21.305	22.853	21.673
D	COST OF ELEC-FUEL	,MILLS/KWE	8.014	7.886	7.676	8.047	8.621	7.917	8.495	6.852
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.848	1.828	1.792	1.805	1.894	1.788	1.878	1.677
W	TOTAL COST OF ELEC	,MILLS/KWE	31.712	32.493	34.310	31.218	33.442	31.010	33.226	30.202
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	38.378	39.438	41.874	37.739	40.431	37.513	40.193	36.816
	COE 0.8 CAP. FACTOR	,MILLS/KWE	27.541	28.147	29.577	27.137	29.068	26.941	28.867	26.064
	COE 1.2XCAP. COST	,MILLS/KWE	36.082	37.048	39.278	35.491	38.027	35.271	37.797	34.537
	COE 1.2XFUEL COST	,MILLS/KWE	33.315	34.070	35.845	32.827	35.166	32.594	34.925	31.573
	COE (CONTINGENCY=0)	,MILLS/KWE	30.130	30.840	32.509	29.670	31.775	29.467	31.565	28.749
	COE (ESCALATION=0)	,MILLS/KWE	27.140	27.726	29.112	26.747	28.644	26.552	28.444	26.124

	PARAMETRIC POINT		41	42	43	44	45	46	47	48
	TOTAL CAPITAL COST	,M$	573.66	965.79	443.08	654.36	1106.02	823.20	421.32	1044.25
P	LIQ MET VAPOR GENERATORS	,M$	45.504	75.840	8.800	13.200	22.000	60.621	30.310	75.776
L	LIQ MET TURBINE	,M$	18.000	30.000	12.000	18.000	30.000	16.000	8.000	20.000
A	STEAM TURB-GEN & FEED STG	,M$	19.228	31.973	12.730	19.115	31.785	25.530	11.905	31.898
N	MET VAP COND-STEAM GEN	,M$	7.863	13.105	5.186	7.779	12.965	10.644	5.322	13.305
T	LIQ MET CIRC & PROCESS SYS	,M$	22.082	31.009	17.112	21.312	29.724	60.033	35.907	72.866
	GAS TURB PUMPUP-REC-PIPING	,M$	22.900	38.000	14.920	22.200	37.000	30.000	15.000	37.500
	LIQ MET AUX ELEC EQUIP	,M$	2.063	3.437	1.375	2.063	3.464	2.750	1.375	3.437
R	TOT MAJOR COMPONENT COST	,M$	137.540	223.363	72.122	103.669	166.938	205.573	107.819	254.782
E	TOT MAJOR COMPONENT COST	,$/KWE	161.001	156.872	125.709	120.474	116.395	180.344	189.168	178.797
S	BALANCE OF PLANT COST	,$/KWE	76.856	71.549	156.378	148.142	142.712	71.742	84.581	71.080
U	SITE LABOR	,$/KWE	88.333	85.729	105.837	100.544	97.876	90.601	98.700	90.460
L	TOTAL DIRECT COST	,$/KWE	326.190	314.151	387.925	369.160	356.983	342.688	372.449	340.337
T	INDIRECT COSTS	,$/KWE	45.050	43.722	53.977	51.278	49.917	46.207	50.337	46.135
	PROF & OWNER COSTS	,$/KWE	26.095	25.132	31.034	29.533	28.559	27.415	29.796	27.227
B	CONTINGENCY COST	,$/KWE	29.947	30.657	33.972	33.892	34.837	32.555	32.617	33.213
R	ESCALATION COST	,$/KWE	111.085	119.087	121.640	125.795	135.391	123.574	116.430	128.659
E	INT DURING CONSTRUCTION	,$/KWE	133.149	145.547	143.735	150.780	165.474	149.720	137.579	157.246
A	TOTAL CAPITALIZATION	,$/KWE	671.515	678.296	772.283	760.438	771.160	722.160	739.208	732.816
K	COST OF ELEC-CAPITAL	,MILLS/KWE	21.228	21.442	24.414	24.039	24.378	22.829	23.368	23.166
D	COST OF ELEC-FUEL	,MILLS/KWE	6.852	6.852	7.293	7.293	7.293	6.756	6.756	6.756
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.678	1.678	1.800	1.800	1.800	1.661	1.661	1.661
W	TOTAL COST OF ELEC	,MILLS/KWE	29.758	29.972	33.506	33.132	33.471	31.246	31.785	31.583
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	36.238	36.516	40.941	40.455	40.895	38.206	38.907	38.644
	COE 0.8 CAP. FACTOR	,MILLS/KWE	25.703	25.877	28.854	28.550	28.825	26.891	27.329	27.165
	COE 1.2XCAP. COST	,MILLS/KWE	34.004	34.260	38.388	37.940	38.346	35.812	36.459	36.216
	COE 1.2XFUEL COST	,MILLS/KWE	31.128	31.342	34.964	34.591	34.929	32.598	33.136	32.934
	COE (CONTINGENCY=0)	,MILLS/KWE	28.270	28.383	31.870	31.448	31.665	29.591	30.214	29.861
	COE (ESCALATION=0)	,MILLS/KWE	25.506	25.331	28.911	28.317	28.195	26.470	27.387	26.569

Table A 8.2.2 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT		49	50	51	52	53	54	55	56
	TOTAL CAPITAL COST	,M$	760.29	882.80	.00	.00	.00	.00	.00	.00
P	LIQ MET VAPOR GENERATORS	,M$	50.572	17.500	.000	.000	.000	.000	.000	.000
L	LIQ MET TURBINE	,M$	24.000	24.000	.000	.000	.000	.000	.000	.000
A	STEAM TURB-GEN & FEED STG	,M$	25.590	25.430	.000	.000	.000	.000	.000	.000
N	MET VAP COND-STEAM GEN	,M$	10.484	9.172	.000	.000	.000	.000	.000	.000
T	LIQ MET CIRC & PROCESS SYS	,M$	36.643	25.518	.000	.000	.000	.000	.000	.000
	GAS TURB PUMPUP-REC-PIPING	,M$	30.400	31.200	.000	.000	.000	.000	.000	.000
	LIQ MET AUX ELEC EQUIP	,M$	2.750	2.750	.000	.000	.000	.000	.000	.000
R	TOT MAJOR COMPONENT COST	,M$	180.539	135.720	.000	.000	.000	.000	.000	.000
E	TOT MAJOR COMPONENT COST	,$/KWE	158.372	118.279	.000	.000	.000	.000	.000	.000
S	BALANCE OF PLANT COST	,$/KWE	71.707	146.216	.000	.000	.000	.000	.000	.000
U	SITE LABOR	,$/KWE	85.579	99.359	.000	.000	.000	.000	.000	.000
L	TOTAL DIRECT COST	,$/KWE	315.658	363.855	.000	.000	.000	.000	.000	.000
T	INDIRECT COSTS	,$/KWE	43.646	50.673	.000	.000	.000	.000	.000	.000
	PROF & OWNER COSTS	,$/KWE	25.253	29.108	.000	.000	.000	.000	.000	.000
B	CONTINGENCY COST	,$/KWE	29.988	34.566	.000	.000	.000	.000	.000	.000
R	ESCALATION COST	,$/KWE	114.126	131.651	.000	.000	.000	.000	.000	.000
E	INT DURING CONSTRUCTION	,$/KWE	138.273	159.506	.000	.000	.000	.000	.000	.000
A	TOTAL CAPITALIZATION	,$/KWE	666.942	769.360	.000	.000	.000	.000	.000	.000
K	COST OF ELEC-CAPITAL	,MILLS/KWE	21.084	24.321	.000	.000	.000	.000	.000	.000
D	COST OF ELEC-FUEL	,MILLS/KWE	6.847	7.293	.000	.000	.000	.000	.000	.000
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.572	1.800	.000	.000	.000	.000	.000	.000
W	TOTAL COST OF ELEC	,MILLS/KWE	29.602	33.413	.000	.000	.000	.000	.000	.000
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	36.039	40.821	.000	.000	.000	.000	.000	.000
	COE 0.8 CAP. FACTOR	,MILLS/KWE	25.574	28.778	.000	.000	.000	.000	.000	.000
	COE 1.2XCAP. COST	,MILLS/KWE	33.819	38.278	.000	.000	.000	.000	.000	.000
	COE 1.2XFUEL COST	,MILLS/KWE	30.971	34.872	.000	.000	.000	.000	.000	.000
	COE (CONTINGENCY=0)	,MILLS/KWE	28.077	31.655	.000	.000	.000	.000	.000	.000
	COE (ESCALATION=0)	,MILLS/KWE	25.191	28.324	.000	.000	.000	.000	.000	.000

Table A 8.2.3

RANKINE METAL VAPOR TOPPING-STEAM CYCLE NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	1	2	3	4	5	6	7	3
COAL, LB/KW-HR	.88127	1.06477	1.42149	.90383	1.00215	1.27605	.86945	.86946
SORBANT OR SEED,LB/KW-HR	.46628	.12096	.13558	.47822	.11384	.12171	.46003	.46003
TOTAL WATER, GAL/KW-HR	.767	.664	.653	.813	.722	.721	.772	.772
COOLING WATER	.611	.581	.565	.601	.591	.594	.618	.618
GASIFIER PROCESS H2O	.00000	.00000	.00000	.05206	.05111	.04793	.00000	.00000
CONDENSATE MAKE UP ,	.00610	.00580	.00564	.00600	.00590	.00593	.00617	.00617
WASTE HANDLING SLURRY	.0965	.0250	.0281	.0990	.0236	.0252	.0952	.0952
SCRUBBER WASTE WATER	.05288	.05271	.05402	.05423	.04961	.04849	.05217	.05217
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	114.59	67.39	69.51	113.94	65.32	67.10	113.54	113.54
MAIN PLANT	16.50	16.26	16.37	17.30	17.00	17.03	16.49	16.49
DISPOSAL LAND	77.24	30.57	34.05	75.98	28.03	29.74	76.21	76.21
LAND FOR ACCESS RR	20.35	20.56	19.10	29.65	20.29	20.33	20.84	20.84

PARAMETRIC POINT	9	10	11	12	13	14	15	16
COAL, LB/KW-HR	.89632	.89382	.88127	.90383	.72812	.77325	.79645	.81435
SORBANT OR SEED,LB/KW-HR	.47424	.47292	.46628	.47821	.38525	.40912	.42140	.43087
TOTAL WATER, GAL/KW-HR	.817	.816	.767	.812	.754	.799	.763	.799
COOLING WATER	.607	.607	.611	.601	.624	.617	.622	.608
GASIFIER PROCESS H2O	.05163	.05148	.00000	.05206	.00000	.04454	.00000	.04691
CONDENSATE MAKE UP ,	.00606	.00606	.00610	.00600	.00676	.00668	.00647	.00637
WASTE HANDLING SLURRY	.0982	.0979	.0965	.0990	.0797	.0847	.0872	.0892
SCRUBBER WASTE WATER	.05378	.05363	.05288	.05423	.04369	.04639	.04779	.04886
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	113.30	113.09	114.59	113.94	100.93	102.81	107.03	106.31
MAIN PLANT	17.30	17.30	16.50	17.30	16.39	17.24	16.44	17.25
DISPOSAL LAND	75.35	75.14	77.24	75.98	63.82	65.00	69.81	68.46
LAND FOR ACCESS RR	20.65	20.65	20.85	20.65	20.72	20.57	20.78	20.60

PARAMETRIC POINT	17	18	19	20	21	22	23	24
COAL, LB/KW-HR	1.00197	.91105	1.62910	2.85522	.82968	.84912	.87884	.87881
SORBANT OR SEED,LB/KW-HR	.53014	.48204	.86196	1.51070	.43899	.44927	.46499	.46498
TOTAL WATER, GAL/KW-HR	.781	.760	.776	.795	.799	.782	.765	.763
COOLING WATER	.605	.599	.495	.308	.652	.632	.610	.608
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00604	.00598	.00494	.00307	.00651	.00631	.00608	.00607
WASTE HANDLING SLURRY	.1097	.0998	.1784	.3127	.0909	.0930	.0963	.0963
SCRUBBER WASTE WATER	.06012	.05466	.09775	.17131	.04978	.05095	.05273	.05273
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	125.37	117.24	176.34	278.54	111.61	113.34	114.37	114.37
MAIN PLANT	16.58	16.52	17.01	17.86	16.47	16.48	16.49	16.49
DISPOSAL LAND	87.82	79.85	142.79	250.26	72.72	74.42	77.03	77.03
LAND FOR ACCESS RR	20.96	20.87	16.54	10.42	22.42	22.43	20.85	20.85

PARAMETRIC POINT	25	26	27	23	29	30	31	32
COAL, LB/KW-HR	.86686	.84825	.86216	.84375	.82609	.89628	.88125	.86450
SORBANT OR SEED,LB/KW-HR	.45865	.44881	.45617	.44643	.43709	.47422	.46627	.45741
TOTAL WATER, GAL/KW-HR	.743	.714	.735	.705	.677	.790	.765	.741
COOLING WATER	.590	.564	.582	.556	.530	.632	.610	.589
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00614	.00619	.00618	.00623	.00628	.00605	.00609	.00612
WASTE HANDLING SLURRY	.0949	.0929	.0944	.0924	.0905	.0982	.0965	.0947
SCRUBBER WASTE WATER	.05201	.05089	.05173	.05062	.04957	.05378	.05287	.05187
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	113.30	110.02	112.87	109.62	106.43	117.55	114.59	113.08
MAIN PLANT	16.48	16.46	16.48	16.46	16.44	16.51	16.50	16.48
DISPOSAL LAND	75.38	74.35	75.57	73.95	72.41	78.56	77.24	75.77
LAND FOR ACCESS RR	20.83	19.21	20.83	19.20	17.58	22.48	20.85	20.83

Table A 8.2.3 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	33	34	35	36	37	38	39	40
COAL, LB/KW-HR	.87400	.85998	.83709	.87760	.94018	.86333	.92644	.74719
SORBANT OR SEED,LB/KW-HR	.46243	.45502	.44290	.46434	.49745	.45679	.49018	.39534
TOTAL WATER, GAL/KW-HR	.754	.749	.636	.155	.165	.152	.163	.795
COOLING WATER	.600	.597	.548	.000	.000	.000	.000	.662
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00614	.00617	.00623	.00608	.00594	.00614	.00599	.00697
WASTE HANDLING SLURRY	.0957	.0942	.0917	.0961	.1030	.0946	.1015	.0818
SCRUBBER WASTE WATER	.05244	.05160	.05023	.05266	.05641	.05180	.05559	.04493
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	113.94	112.68	109.02	93.35	178.51	92.09	175.60	112.72
MAIN PLANT	16.49	16.48	16.45	16.43	16.67	16.42	16.66	24.88
DISPOSAL LAND	76.61	75.38	73.37	76.92	82.41	75.67	81.20	65.49
LAND FOR ACCESS RR	20.84	20.83	19.20	.00	79.43	.00	77.74	22.35

PARAMETRIC POINT	41	42	43	44	45	46	47	48
COAL, LB/KW-HR	.74726	.74723	.79091	.79098	.79095	.73677	.73677	.73673
SORBANT OR SEED,LB/KW-HR	.39538	.39536	.41847	.41851	.41849	.38982	.38982	.38980
TOTAL WATER, GAL/KW-HR	.796	.796	.839	.839	.839	.780	.780	.780
COOLING WATER	.652	.662	.652	.652	.652	.649	.648	.649
GASIFIER PROCESS H2O	.00000	.00000	.04556	.04556	.04556	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00697	.00697	.00687	.00687	.00687	.00683	.00683	.00683
WASTE HANDLING SLURRY	.0818	.0818	.0866	.0866	.0866	.0807	.0807	.0807
SCRUBBER WASTE WATER	.04484	.04483	.04745	.04746	.04746	.04421	.04421	.04420
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	108.42	102.84	114.83	110.25	104.41	103.31	111.77	100.61
MAIN PLANT	19.51	14.36	26.15	20.51	15.09	16.40	24.85	14.35
DISPOSAL LAND	65.50	65.49	66.49	66.49	66.49	64.58	64.[illegible]3	64.57
LAND FOR ACCESS RR	23.41	22.99	22.18	23.24	22.82	22.33	22.33	21.69

PARAMETRIC POINT	49	50	51	52	53	54	55	56
COAL, LB/KW-HR	.74665	.79091	.00000	.00000	.00000	.00000	.00000	.00000
SORBANT OR SEED,LB/KW-HR	.39505	.41847	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.737	.839	.000	.000	.000	.000	.000	.000
COOLING WATER	.603	.652	.000	.000	.000	.000	.000	.000
GASIFIER PROCESS H2O	.00000	.04556	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00696	.00687	.00000	.00000	.00000	.00000	.00000	.00000
WASTE HANDLING SLURRY	.0818	.0866	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.04480	.04745	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	102.58	105.93	.00	.00	.00	.00	.00	.00
MAIN PLANT	16.40	17.26	.00	.00	.00	.00	.00	.00
DISPOSAL LAND	65.44	66.49	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	20.73	22.18	.00	.00	.00	.00	.00	.00

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APPENDIX A 8.3

DETAILED ACCOUNTS LISTING
POINTS 1, 4, 49, and 46

Table A 8.3.1

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING

PARAMETRIC POINT NO. 1

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	187.0	1000.00	.00	187000.00	.00
1. 2 CLEARING LAND	ACRE	62.3	.00	600.00	.00	37396.25
1. 3 GRADING LAND	ACRE	187.0	.00	3000.00	.00	561000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.5	120000.00	70000.00	300000.00	175000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	396406.86	396406.86
PERCENT TOTAL DIRECT COST IN ACCOUNT		1 =	.864	ACCOUNT TOTAL,$	1458406.86	1719803.11
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	75150.0	.00	3.00	.00	225450.00
2. 2 PILING	FT	200400.0	6.50	8.50	1302600.00	1703400.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		2 =	.878	ACCOUNT TOTAL,$	1302600.00	1928850.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	25050.0	70.00	80.00	1753500.00	2004000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		3 =	1.021	ACCOUNT TOTAL,$	1753500.00	2004000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	13.0	.00	.00	1995500.00	994500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	1139243.23	1527591.19
4. 3 SURFACE CONDENSER	FT2	384080.2	.00	.00	1747562.12	268856.17
PERCENT TOTAL DIRECT COST IN ACCOUNT		4 =	2.086	ACCOUNT TOTAL,$	4882305.31	2790937.34
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	27300.0	650.00	175.00	17745000.00	4777500.00
5. 2 SILOS & BUNKERS	TPH	.0	1800.00	750.00	.00	.00
5. 3 CHIMNEY	FT	.0	.00	.00	.00	.00
5. 4 STRUCTURAL FEATURES	EACH	1.0	725000.00	166000.00	725000.00	166000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		5 =	6.364	ACCOUNT TOTAL,$	18470000.00	4943500.00
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	7500000.0	.15	.16	1200000.00	1200000.00
6. 2 ADMINSTRATION	FT2	20000.0	16.00	14.00	320000.00	280000.00
6. 3 WAREHOUSE & SHOP	FT2	20000.0	12.00	8.00	240000.00	160000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		6 =	.924	ACCOUNT TOTAL,$	1760000.00	1640000.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	499.5	.00	.00	10117825.12	4313571.81
7. 2 DOLOMITE HAND. SYS	TPH	264.3	.00	.00	3469001.50	1567851.77
7. 3 FUEL OIL HAND. SYS	GAL	2600000.0	.00	.00	290836.01	227825.41
PERCENT TOTAL DIRECT COST IN ACCOUNT		7 =	5.433	ACCOUNT TOTAL,$	13877662.62	6109249.94
FUEL PROCESSING						
8. 1 COAL DRYER & CRUSHER	TPH	.0	.00	.00	.00	.00
8. 2 CARBONIZERS	TPH	.0	.00	.00	.00	.00
8. 3 GASIFIERS	TPH	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		8 =	.000	ACCOUNT TOTAL,$	.00	.00

Table A 8.3.1 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 1

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
FIRING SYSTEM						
9. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 9 = .000 ACCOUNT TOTAL,$					.00	.00
VAPOR GENERATOR (FIRED)						
10. 1 PRESSURIZE BOILER	EA	.0	.00	.00	.00	.00
10. 2 FLUID BED BOILER	EA	4.0	14912000.00	8387999.94	59648000.00	33551999.75
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =25.333 ACCOUNT TOTAL,$					59648000.00	33551999.75
ENERGY CONVERTER						
11. 1 STEAM TURBINE GENERATOR		1.0	19700000.00	1255014.50	19700000.00	1255014.50
11. 2 GAS TURBINE GENERATOR		4.0	7200000.00	1576000.00	28800000.00	6304000.00
11. 3 LIQUID METAL TURB-GEN		8.0	3000000.00	270000.00	24000000.00	2159999.97
11. 4 LIQUID METAL DRUM		4.0	650000.00	95000.00	2600000.00	380000.00
11. 5 LIQUID MET RECIRC PUMP		4.0	215000.00	17200.00	860000.00	68800.00
11. 6 LIQ MET HOT LEG PIPING		2000.0	2330.00	780.00	4660000.00	1560000.00
11. 7 LIQ MET COLD LEG PIPE		1300.0	310.00	104.00	403000.00	135200.00
11. 8 LIQ MET CONDENSATE PUMP		4.0	450000.00	36000.00	1800000.00	144000.00
11. 9 LIQ MET INVENTORY		1.0	675000.00	13500.00	675000.00	13500.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =25.963 ACCOUNT TOTAL,$					83498000.00	12020514.37
COUPLING HEAT EXCHANGER						
12. 1 L M COND-STEAM GEN	EA	4.0	1610000.00	690000.00	6440000.00	2760000.00
12. 2 HOT WELL TANK	EA	4.0	725000.00	110000.00	2900000.00	440000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = 3.409 ACCOUNT TOTAL,$					9340000.00	3200000.00
HEAT RECOVERY HEAT EXCH.						
13. 1 GAS-AIR RECUPERATOR	EA	.0	.00	.00	.00	.00
13. 2 ECONOMIZER	EA	.0	.00	.00	.00	.00
13. 3 GAS FEED WATER HEATER	EA	.0	.00	.00	.00	.00
13. 4 FEED WATER HEATER STRING		1.0	1500000.00	45000.00	1500000.00	45000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = .420 ACCOUNT TOTAL,$					1500000.00	45000.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	115.3	2500.00	700.00	288239.99	80707.20
14. 2 CONDENSATE POLISHING	KWE	720600.0	1.25	.30	900749.98	216180.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .404 ACCOUNT TOTAL,$					1188989.97	296887.20
POWER CONDITIONING						
15. 1 STM TURB TRANSFORMER		880733.3	.00	.00	1594347.28	31886.95
15. 2 MET VAP TURB TRANSFORMER		229655.6	.00	.00	4507163.12	637.74
15. 3 GAS TURB TRANSFORMER		356277.8	.00	.00	2545736.06	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 2.359 ACCOUNT TOTAL,$					8647246.37	32524.68

Table A 8.3.1 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 1

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY MECH EQUIPMENT						
15. 1 BOILER FEED PUMP DR.	KWE	684570.0	1.67	.10	1143231.87	68457.00
16. 2 OTHER PUMPS	KWE	684000.0	.88	.12	601920.00	82080.00
16. 3 MISC SERVICE SYS	KWE	1140000.0	1.17	.73	1333800.00	832199.99
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.30	.00	.00
16. 5 LIQ MET RECEIVING-PROC		1.0	6200000.00	2000000.00	6200000.00	2000000.00
16. 6 LIQ MET STORAGE TANK	EA	4.0	1300000.00	150000.00	5200000.00	600000.00
16. 7 LIQ MET IMPURITY MONITOR		1.0	800000.00	250000.00	800000.00	250000.00
16. 8 COVER GAS SYSTEM	EA	1.0	1700000.00	400000.00	1700000.00	400000.00
16. 9 LIQ MET DUMP TANK	EA	4.0	570000.00	85000.00	2280000.00	344000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 6.479 ACCOUNT TOTAL,$					19258951.75	4576736.94
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	1370.0	3000.00	1800.00	4110000.00	2466000.00
17. 2 HOT GAS PIPING	EA	4.0	2200000.00	.00	8800000.00	.00
17. 3 STEAM PIPING & FITTINGS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 4.179 ACCOUNT TOTAL,$					12910000.00	2466000.00
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTORS,ETC		1140000.0	1.40	.17	1596000.00	193800.00
18. 2 SWITCHGEAR & MCC PAN	KWE	1140000.0	1.95	.45	2223000.00	513000.00
18. 3 CONDUIT,CABLES,TRAYS	FT	4930000.0	1.32	1.36	5507599.94	6704799.94
18. 4 ISOLATED PHASE BUS	FT	1700.0	510.00	450.00	867000.00	765000.00
18. 5 LIGHTING & COMMUN	KWE	1140000.0	.35	.43	399000.00	490200.00
18. 6 LM LEAK DETECTION SYS	EA	1.0	250000.00	200000.00	250000.00	200000.00
18. 7 LM TRACE HEATING SYSTEM		1.0	2500000.00	2000000.00	2500000.00	2000000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 6.852 ACCOUNT TOTAL,$					14342599.87	10866799.75
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	660000.00	15000.00	660000.00	15000.00
19. 2 OTHER CONTROLS	EACH	1.0	1250000.00	774000.00	1250000.00	774000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = .734 ACCOUNT TOTAL,$					1910000.00	789000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	48.0	2727631.06	681907.77	2727631.06	681907.77
20. 3 WET SLURRY	TPH	264.3	6708132.31	1677033.08	6708132.31	1677033.08
20. 4 ONSITE DISPOSAL	ACRE	875.6	5126.87	7865.19	4489103.44	6886791.06
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 5.298 ACCOUNT TOTAL,$					13924866.75	9245731.87
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	8784224.25	5709745.69	.00	.00
21. 2 SCRUBBER	KWE	.0	21.51	9.86	.00	.00
21. 3 MISC STEEL & DUCTS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 21 = .000 ACCOUNT TOTAL,$					.00	.00
TOTAL DIRECT COSTS,$					269573120.00	98227531.00

Table A 8.3.2

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO. 1

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 5.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	325273608.	348440476.	367900648.	408674340.	468908204.
INDIRECT COST,$	51.0	28356249.	40171302.	50096040.	70890622.	101609892.
PROF & OWNER COSTS,$	8.0	26021083.	27875238.	29432052.	32693947.	37512656.
CONTINGENCY COST,$	9.5	30900392.	33101845.	34950561.	38824062.	44546279.
SUB TOTAL,$	.0	410552736.	449588908.	482379296.	551082960.	652577024.
ESCALATION COST,$	6.5	113026815.	123773630.	132800955.	151715348.	179657072.
INTREST DURING CONST,$	10.0	136941122.	149961822.	160899162.	183815490.	217669160.
TOTAL CAPITALIZATION,$	.0	660520723.	723324352.	776079408.	886613792.	1049903256.
COST OF ELEC-CAPITAL	18.0	18.41957	20.17138	21.64255	24.72504	29.27870
COST OF ELEC-FUEL	.0	8.08106	8.08106	8.08106	8.08106	8.08106
COST OF ELEC-OP & MAIN	.0	1.86282	1.86282	1.86282	1.86282	1.86282
TOTAL COST OF ELEC	.0	28.36336	30.11527	31.58645	34.66893	39.22259

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	9.50	5.00	20.00
TOTAL DIRECT COSTS,$	.0	367900648.	367900648.	367900648.	367900648.	367900648.
INDIRECT COST,$	51.0	50096040.	50096040.	50096040.	50096040.	50096040.
PROF & OWNER COSTS,$	8.0	29432052.	29432052.	29432052.	29432052.	29432052.
CONTINGENCY COST,$	20.0	-18395032.	0.	34950561.	18395032.	73580129.
SUB TOTAL,$	.0	429033704.	447428736.	482379296.	465823768.	521008864.
ESCALATION COST,$	6.5	118114699.	123178926.	132800955.	128243152.	143435630.
INTREST DURING CONST,$	10.0	143105563.	149241230.	160899162.	155377012.	173784178.
TOTAL CAPITALIZATION,$	.0	690253958.	719848944.	776079403.	749443928.	878228664.
COST OF ELEC-CAPITAL	18.0	19.24914	20.07446	21.64256	20.89973	23.37573
COST OF ELEC-FUEL	.0	8.08106	8.08106	8.08106	8.08106	8.08106
COST OF ELEC-OP & MAIN	.0	1.86282	1.86282	1.86282	1.86232	1.86282
TOTAL COST OF ELEC	.0	29.19303	30.01835	31.58645	30.84367	33.31961

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	367900643.	367900649.	367900648.	367900648.	367900648.
INDIRECT COST,$	51.0	50096040.	50096040.	50096040.	50096040.	50096040.
PROF & OWNER COSTS,$	8.0	29432052.	29432052.	29432052.	29432052.	29432052.
CONTINGENCY COST,$	9.5	34950561.	34950561.	34950561.	34950561.	34950561.
SUB TOTAL,$	.0	482379296.	482379296.	482379296.	482379296.	482379296.
ESCALATION COST,$	.0	99685749.	132800955.	167499892.	216332698.	0.
INTREST DURING CONST,$	10.0	153624106.	160899162.	168456552.	178986752.	131308481.
TOTAL CAPITALIZATION,$	.0	735689144.	776079408.	818335736.	877693744.	613687776.
COST OF ELEC-CAPITAL	18.0	20.51520	21.64256	22.82097	24.47643	17.11394
COST OF ELEC-FUEL	.0	8.08106	8.08106	8.08106	8.08106	8.08106
COST OF ELEC-OP & MAIN	.0	1.86282	1.86282	1.86282	1.86282	1.86282
TOTAL COST OF ELEC	.0	30.46009	31.58645	32.76485	34.42031	27.05783

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	367900648.	367900648.	367900648.	367900643.	367900643.
INDIRECT COST,$	51.0	50096040.	50096040.	50096040.	50096040.	50096040.
PROF & OWNER COSTS,$	8.0	29432052.	29432052.	29432052.	29432052.	29432052.
CONTINGENCY COST,$	9.5	34950561.	34950561.	34950561.	34950561.	34950561.
SUB TOTAL,$	.0	482379296.	482379296.	482379296.	482379296.	482379296.
ESCALATION COST,$	6.5	132800955.	132800955.	132800955.	132800955.	132800955.
INTREST DURING CONST,$	15.0	92726997.	126149246.	160899162.	206271256.	253876664.
TOTAL CAPITALIZATION,$	.0	707907240.	741329468.	776079408.	821451504.	869056912.
COST OF ELEC-CAPITAL	18.0	19.74144	20.67349	21.64256	22.90786	24.23543
COST OF ELEC-FUEL	.0	8.08106	8.08106	8.08100	8.08106	8.08106
COST OF ELEC-OP & MAIN	.0	1.85232	1.86282	1.86282	1.86282	1.86232
TOTAL COST OF ELEC	.0	29.68533	30.61738	31.58645	32.85179	34.17932

Table A 8.3.2 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO. 1

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	367900648.	367900648.	367900648.	367900648.	367900648.
INDIRECT COST,$	51.0	50035040.	50096040.	50096040.	50096040.	50096040.
PROF & OWNER COSTS,$	8.0	29432052.	29432052.	29432052.	29432052.	29432052.
CONTINGENCY COST,$	9.5	34950561.	34950561.	34950561.	34950561.	34950561.
SUB TOTAL,$	.0	482379296.	482379296.	482379296.	462379296.	482379296.
ESCALATION COST,$	6.5	132800955.	132800955.	132800955.	132800955.	132800955.
INTREST DURING CONST,$	10.0	160899162.	160899162.	160899162.	160899162.	160899162.
TOTAL CAPITALIZATION,$	.0	776079403.	776079408.	775079408.	776073408.	775073408.
COST OF ELEC-CAPITAL	25.0	12.02365	17.31405	21.64256	25.97108	30.05912
COST OF ELEC-FUEL	.0	8.08106	8.08106	8.08106	8.08106	8.08105
COST OF ELEC-OP & MAIN	.0	1.86282	1.86282	1.86282	1.86282	1.86282
TOTAL COST OF ELEC	.0	21.96753	27.25794	31.58645	35.91496	40.00300

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	367900648.	367900648.	367900648.	367900648.	367900648.
INDIRECT COST,$	51.0	50096040.	50096040.	50096040.	50096040.	50096040.
PROF & OWNER COSTS,$	8.0	29432052.	29432052.	29432052.	29432052.	29432052.
CONTINGENCY COST,$	9.5	34950561.	34950561.	34950561.	34950561.	34950561.
SUB TOTAL,$	.0	482379296.	482379296.	482379296.	482379296.	482379296.
ESCALATION COST,$	6.5	132800955.	132800955.	132800955.	132800955.	132800955.
INTREST DURING CONST,$	10.0	160899162.	160899162.	160899162.	160899162.	160899162.
TOTAL CAPITALIZATION,$	.0	776079408.	776079408.	776079408.	776073408.	776079408.
COST OF ELEC-CAPITAL	18.0	21.64256	21.64256	21.64256	21.64256	21.64256
COST OF ELEC-FUEL	.0	4.75357	8.08106	14.26070	23.76783	9.69728
COST OF ELEC-OP & MAIN	.0	1.86282	1.86282	1.86282	1.86282	1.86282
TOTAL COST OF ELEC	.0	28.25895	31.58645	37.76609	47.27322	33.20266

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	367900648.	367900648.	367900648.	367900648.	367900648.
INDIRECT COST,$	51.0	50096040.	50096040.	50096040.	50096040.	50096040.
PROF & OWNER COSTS,$	8.0	29432052.	29432052.	29432052.	29432052.	29432052.
CONTINGENCY COST,$	9.5	34950561.	34950561.	34950561.	34950561.	34950561.
SUB TOTAL,$	.0	482379296.	482379296.	482379296.	482379296.	482379296.
ESCALATION COST,$	6.5	132800955.	132800955.	132800955.	132800955.	132800955.
INTREST DURING CONST,$	10.0	160899162.	160899162.	160899162.	160899162.	160899162.
TOTAL CAPITALIZATION,$	.0	776079408.	776079408.	776079408.	776079409.	776079408.
COST OF ELEC-CAPITAL	18.0	117.23055	31.26148	28.13533	21.64256	17.58458
COST OF ELEC-FUEL	.0	8.08106	8.08106	8.08106	8.08106	8.08105
COST OF ELEC-OP & MAIN	.0	3.11789	2.02498	1.97815	1.86282	1.78821
TOTAL COST OF ELEC	.0	128.42950	41.36752	38.19054	31.58645	27.45386

Table A 8.3.3

RANKINE METAL VAPOR TOPPING-STEAM CYCLE

ACCOUNT NO	AUX POWER, MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	8.99750	13.54654	55.44310	13.13911
7	7.29061	10.97667	1413.91312	.00000
8	11.97123	18.02377	.00000	.00000
14	.00000	.00000	12.47066	.00000
18	10.32360	15.54311	.00000	.00000
20	27.83519	41.90991	8.75305	.00000
TOTALS	66.41913	5.85923	1490.57990	13.13911

RANKINE METAL VAPOR TOPPING-STEAM CYCLE BASE CASE INPUT

NOMINAL POWER, MWE	1200.0000	NET POWER, MWE	1133.5809
NOM HEAT RATE, BTU/KW-HR	8980.9207	NET HEAT RATE, BTU/KW-HR	9507.1334
ST TURB HEAT RATE CHANGE	1.0170		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	3.0000
NUMBER OF TUBES/SHELL	7035.5720	TUBE LENGTH, FT	69.5067
U, BTU/HR-FT2-F	608.5535	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	51.4000
OFF DESIGN PRES, IN HG A	4.1186	LP TURBINE BLADE LEN, IN	25.0000

1	1200.000	2	.000	3	.380	4	.000	5	6.500
6	720.600	7	3.500	8	3396000000.000	9	3.000	10	1.000
11	1.000	12	291.500	13	1.000	14	.000	15	.000
16	2.000	17	187.000	18	3.000	19	5.000	20	2.500
21	.000	22	25050.000	23	.000	24	27300.000	25	.000
26	7500000.000	27	20000.000	28	20000.000	29	2600000.000	30	.600
31	1.000	32	1370.000	33	.000	34	1.000	35	1.000
36	4930000.000	37	1700.000	38	1.000	39	1.000	40	725000.000
41	166000.000	42	660000.000	43	15000.000	44	1250000.000	45	774000.000
46	.000	47	.000	48	3.000	49	2.000	50	.000
51	.000	52	5.350						

1	.000	2	4.000	3	.000	4	.000	5	23300000.000
6	.000	7	1.000	8	4.000	9	8.000	10	4.000
11	4.000	12	2000.000	13	1300.000	14	4.000	15	1.000
16	19700000.000	17	.000	18	7200000.000	19	.000	20	3000000.000
21	.000	22	650000.000	23	95000.000	24	215000.000	25	.000
26	2330.000	27	780.000	28	310.000	29	104.000	30	450000.000
31	.000	32	675000.000	33	.000	34	4.000	35	4.000
36	2300000.000	37	.000	38	725000.000	39	110000.000	40	.000
41	.000	42	.000	43	1.000	44	.000	45	.000
46	.000	47	.000	48	.000	49	.000	50	.000
51	.000	52	1500000.000	53	.000	54	.000	55	.000
56	.000	57	.000	58	1.000	59	4.000	60	1.000
61	1.000	62	4.000	63	6200000.000	64	2000000.000	65	1300000.000
66	150000.000	67	800000.000	68	250000.000	69	1700000.000	70	400000.000
71	570000.000	72	36000.000	73	4.000	74	2200000.000	75	.000
76	1.000	77	1.000	78	250000.000	79	200000.000	80	2500000.000
81	2000000.000	82	.000	83	.000	84	.000	85	.000
86	.900	87	.000	88	.000	89	.000	90	1.000
91	.000	92	.000	93	.000	94	.000	95	.000
96	.000	97	.000	98	.000	99	.000	100	.000

Table A 8.3.4

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 4

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	198.0	1000.00	.00	198000.00	.00
1. 2 CLEARING LAND	ACRE	66.0	.00	600.00	.00	39596.04
1. 3 GRADING LAND	ACRE	198.0	.00	3000.00	.00	594000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	3.0	120000.00	70000.00	360000.00	210000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	416889.52	416889.52
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 = .767 ACCOUNT TOTAL,$					1549889.52	1810485.55
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	71550.0	.00	3.00	.00	214650.00
2. 2 PILING	FT	190800.0	6.50	8.50	1240200.00	1621800.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 = .702 ACCOUNT TOTAL,$					1240200.00	1836450.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	23850.0	70.00	80.00	1669500.00	1308000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 = .817 ACCOUNT TOTAL,$					1669500.00	1908000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	13.0	.00	.00	1995500.00	994500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	1131192.05	1516785.56
4. 3 SURFACE CONDENSER	FT2	381365.9	.00	.00	1738058.08	266956.12
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 = 1.745 ACCOUNT TOTAL,$					4864750.06	2778241.69
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	27300.0	650.00	175.00	17745000.00	4777500.00
5. 2 SILOS & BUNKERS	TPH	.0	1800.00	750.00	.00	.00
5. 3 CHIMNEY	FT	.0	.00	.00	.00	.00
5. 4 STRUCTURAL FEATURES	EACH	1.0	725000.00	165000.00	725000.00	165000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 5 = 5.346 ACCOUNT TOTAL,$					18470000.00	4943500.00
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	7500000.0	.16	.16	1200000.00	1200000.00
6. 2 ADMINSTRATION	FT2	20000.0	16.00	14.00	320000.00	280000.00
6. 3 WAREHOUSE & SHOP	FT2	20000.0	12.00	8.00	240000.00	160000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 = .776 ACCOUNT TOTAL,$					1760000.00	1640000.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	517.2	.00	.00	10319369.87	4364834.87
7. 2 DOLOMITE HAND. SYS	TPH	273.6	.00	.00	3579441.31	1610568.86
7. 3 FUEL OIL HAND. SYS	GAL	2600000.0	.00	.00	290836.01	227826.41
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 = 4.656 ACCOUNT TOTAL,$					14189647.12	6203230.06
FUEL PROCESSING						
8. 1 COAL DRYER & CRUSHER	TPH	.0	.00	.00	.00	.00
8. 2 CARBONIZERS	TPH	.0	.00	.00	.00	.00
8. 3 GASIFIERS	TPH	517.2	.00	.00	90190844.00	50732349.50
PERCENT TOTAL DIRECT COST IN ACCOUNT 8 =32.175 ACCOUNT TOTAL,$					90190844.00	50732349.50

Table A 8.3.4 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 5

ACCOUNT NO. & NAME.	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
FIRING SYSTEM						
9. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 9 = .000 ACCOUNT TOTAL,$					.00	.00
VAPOR GENERATOR (FIRED)						
10. 1 PRESSURIZE BOILER	EA	8.0	2200000.00	450000.00	17600000.00	3600000.00
10. 2 FLUID BED BOILER	EA	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 = 4.840 ACCOUNT TOTAL,$					17600000.00	3600000.00
ENERGY CONVERTER						
11. 1 STEAM TURBINE GENERATOR		1.0	19700000.00	1257514.48	19700000.00	1257514.48
11. 2 GAS TURBINE GENERATOR		4.0	7100000.00	1576000.00	28400000.00	6304000.00
11. 3 LIQUID METAL TURB-GEN		8.0	3000000.00	270000.00	24000000.00	2159999.97
11. 4 LIQUID METAL DRUM		4.0	625000.00	90000.00	2500000.00	360000.00
11. 5 LIQUID MET RECIRC PUMP		4.0	215000.00	17200.00	860000.00	68800.00
11. 6 LIQ MET HOT LEG PIPING		2000.0	1820.00	630.00	3640000.00	1260000.00
11. 7 LIQ MET COLD LEG PIPE		1300.0	310.00	104.00	403000.00	135200.00
11. 8 LIQ MET CONDENSATE PUMP		4.0	450000.00	36000.00	1800000.00	144000.00
11. 9 LIQ MET INVENTORY		1.0	665000.00	13300.00	665000.00	13300.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =21.387 ACCOUNT TOTAL,$					81968000.00	11702814.37
COUPLING HEAT EXCHANGER						
12. 1 L M COND-STEAM GEN	EA	4.0	1610000.00	690000.00	6440000.00	2760000.00
12. 2 HOT WELL TANK	EA	4.0	725000.00	110000.00	2900000.00	440000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = 2.863 ACCOUNT TOTAL,$					9340000.00	3200000.00
HEAT RECOVERY HEAT EXCH.						
13. 1 GAS-AIR RECUPERATOR	EA	.0	.00	.00	.00	.00
13. 2 ECONOMIZER	EA	.0	.00	.00	.00	.00
13. 3 GAS FEED WATER HEATER	EA	.0	.00	.00	.00	.00
13. 4 FEED WATER HEATER STRING		1.0	1500000.00	45000.00	1500000.00	45000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = .353 ACCOUNT TOTAL,$					1500000.00	45000.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	1107.4	2000.00	560.00	2214824.53	620150.87
14. 2 CONDENSATE POLISHING	KWE	715300.0	1.25	.30	894125.00	214590.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .900 ACCOUNT TOTAL,$					3108949.53	834740.87
POWER CONDITIONING						
15. 1 STM TURB TRANSFORMER		874255.5	.00	.00	1586509.19	31730.18
15. 2 MET VAP TURB TRANSFORMER		227455.6	.00	.00	4504501.12	634.60
15. 3 GAS TURB TRANSFORMER		364955.5	.00	.00	2556236.19	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.982 ACCOUNT TOTAL,$					8647246.50	32364.79

Table A 8.3.4 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 4

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	579535.0	1.67	.10	1134823.44	67953.50
16. 2 OTHER PUMPS	KWE	684000.0	.88	.12	601920.00	82080.00
16. 3 MISC SERVICE SYS	KWE	1140000.0	1.17	.73	1333800.00	832199.99
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
16. 5 LIQ MET RECEIVING-PROC		1.0	6200000.00	2000000.00	6200000.00	2000000.00
16. 6 LIQ MET STORAGE TANK	EA	4.0	1300000.00	150000.00	5200000.00	600000.00
16. 7 LIQ MET IMPURITY MONITOR		1.0	800000.00	250000.00	800000.00	250000.00
16. 8 COVER GAS SYSTEM	EA	1.0	1700000.00	400000.00	1700000.00	400000.00
16. 9 LIQ MET DUMP TANK	EA	4.0	570000.00	86000.00	2280000.00	344000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 5.440 ACCOUNT TOTAL,$					19250543.25	4576233.44
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	1540.0	3000.00	1800.00	4620000.00	2772000.00
17. 2 HOT GAS PIPING	EA	4.0	2000000.00	.00	8000000.00	.00
17. 3 STEAM PIPING & FITTINGS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 3.514 ACCOUNT TOTAL,$					12620000.00	2772000.00
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		1140000.0	1.40	.17	1596000.00	193800.00
18. 2 SWITCHGEAR & MCC PAN	KWE	1140000.0	1.95	.45	2223000.00	513000.00
18. 3 CONDUIT,CABLES,TRAYS	FT	4930000.0	1.32	1.36	6507599.94	6704799.94
18. 4 ISOLATED PHASE BUS	FT	1700.0	510.00	450.00	867000.00	765000.00
18. 5 LIGHTING & COMMUN	KWE	1140000.0	.35	.43	399000.00	490200.00
18. 6 LM LEAK DETECTION SYS	EA	1.0	250000.00	200000.00	250000.00	200000.00
18. 7 LM TRACE HEATING SYSTEM		1.0	2500000.00	2000000.00	2500000.00	2000000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 5.756 ACCOUNT TOTAL,$					14342599.87	10866799.75
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	660000.00	15000.00	660000.00	15000.00
19. 2 OTHER CONTROLS	EACH	1.0	1250000.00	774000.00	1250000.00	774000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = .616 ACCOUNT TOTAL,$					1910000.00	789000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	49.6	2804410.69	701102.67	2804410.69	701102.67
20. 3 WET SLURRY	TPH	273.6	6945489.19	1736372.30	6945489.19	1736372.30
20. 4 ONSITE DISPOSAL	ACRE	869.5	5131.90	7873.33	4462321.12	346066.81
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 5.364 ACCOUNT TOTAL,$					14212221.00	83541.75
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	9025730.50	5866724.75	.00	.00
21. 2 SCRUBBER	KWE	.0	21.72	9.96	.00	.00
21. 3 MISC STEEL & DUCTS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 21 = .000 ACCOUNT TOTAL,$					.00	.00
TOTAL DIRECT COSTS,$					318434380.00	119554747.00

Table A 8.3.5

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY, MILLS/KW.HR
PARAMETRIC POINT NO. 4

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	386106876.	414303748.	437989124.	487615624.	560927496.
INDIRECT COST,$	51.0	34512973.	48893379.	60972920.	86282434.	123671488.
PROF & OWNER COSTS,$	8.0	30888550.	33144300.	35039129.	39009243.	44874199.
CONTINGENCY COST,$	9.5	36680153.	39358855.	41608966.	46323484.	53288111.
SUB TOTAL,$	.0	488188548.	535700272.	575610136.	659230784.	782761280.
ESCALATION COST,$	5.5	134400264.	147480434.	158467778.	181488873.	215497320.
INTREST DURING CONST,$	10.0	162836856.	178684544.	191996608.	219888544.	261092536.
TOTAL CAPITALIZATION,$	.0	785425664.	861865248.	926074520.	1060608200.	1259351136.
COST OF ELEC-CAPITAL	13.0	21.69633	23.80787	25.58156	29.29787	34.78788
COST OF ELEC-FUEL	.0	9.33370	8.33370	8.33370	8.33370	8.33370
COST OF ELEC-OP & MAIN	.0	1.96351	1.96351	1.96351	1.96351	1.96351
TOTAL COST OF ELEC	.0	31.99353	34.10507	35.87877	39.59508	45.08509

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	9.50	5.00	20.00
TOTAL DIRECT COSTS,$	.0	437989124.	437989124.	437989124.	437989124.	437989124.
INDIRECT COST,$	51.0	60972920.	60972920.	60972920.	60972920.	60972920.
PROF & OWNER COSTS,$	8.0	35039129.	35039129.	35039129.	35039129.	35039129.
CONTINGENCY COST,$	20.0	-21899456.	0.	41608966.	21899456.	87597824.
SUB TOTAL,$	.0	512101716.	534001172.	575610136.	555900624.	621598992.
ESCALATION COST,$	6.5	140983656.	147012664.	158467778.	153041672.	171128696.
INTREST DURING CONST,$	10.0	170813170.	178117804.	191996608.	185422436.	207336338.
TOTAL CAPITALIZATION,$	.0	823898536.	859131632.	926074520.	894364728.	1000064024.
COST OF ELEC-CAPITAL	18.0	22.75909	23.73235	25.58155	24.70562	27.62542
COST OF ELEC-FUEL	.0	8.33370	8.33370	8.33370	8.33370	8.33370
COST OF ELEC-OP & MAIN	.0	1.96351	1.96351	1.96351	1.96351	1.96351
TOTAL COST OF ELEC	.0	33.05629	34.02956	35.87877	35.00283	37.92263

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	437989124.	437989124.	437989124.	437989124.	437989124.
INDIRECT COST,$	51.0	60972920.	60972920.	60972920.	60972920.	60972920.
PROF & OWNER COSTS,$	8.0	35039129.	35039129.	35039129.	35039129.	35039129.
CONTINGENCY COST,$	9.5	41608966.	41608966.	41608966.	41608966.	41608966.
SUB TOTAL,$	.0	575610136.	575610136.	575610136.	575610136.	575610136.
ESCALATION COST,$	.0	118952302.	158467778.	199873080.	258143944.	0.
INTREST DURING CONST,$	10.0	183315482.	191996608.	201014638.	213580040.	156686850.
TOTAL CAPITALIZATION,$	.0	877877912.	925074520.	976497848.	1047334120.	732296984.
COST OF ELEC-CAPITAL	18.0	24.25019	25.58156	26.97444	28.93119	20.22872
COST OF ELEC-FUEL	.0	8.33370	8.33370	8.33370	8.33370	8.33370
COST OF ELEC-OP & MAIN	.0	1.96351	1.96351	1.96351	1.96351	1.96351
TOTAL COST OF ELEC	.0	34.54740	35.87877	37.27164	39.22840	30.52592

ACCOUNT	RATE, PERCENT	INT DURING CONST, PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	437939124.	437989124.	437989124.	437989124.	437989124.
INDIRECT COST,$	51.0	60972920.	60972920.	60972920.	60972920.	60972920.
PROF & OWNER COSTS,$	8.0	35039129.	35039129.	35039129.	35039129.	35039129.
CONTINGENCY COST,$	9.5	41608966.	41608966.	41608966.	41608966.	41608966.
SUB TOTAL,$	.0	575610136.	575610136.	575610136.	575610136.	575610136.
ESCALATION COST,$	6.5	158467778.	158467778.	158467778.	158467778.	158467778.
INTREST DURING CONST,$	15.0	110648611.	150530476.	191996608.	246137898.	302944190.
TOTAL CAPITALIZATION,$	.0	844726520.	884608384.	926074520.	980215808.	1037022048.
COST OF ELEC-CAPITAL	18.0	23.33443	24.43511	25.58156	27.07714	28.64634
COST OF ELEC-FUEL	.0	8.33370	8.33370	8.33370	8.33370	8.33370
COST OF ELEC-OP & MAIN	.0	1.96351	1.96351	1.96351	1.96351	1.96351
TOTAL COST OF ELEC	.0	33.63164	34.73332	35.87877	37.37435	38.94354

Table A 8.3.5 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO. 4

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	437989124.	437989124.	437989124.	437989124.	437989124.
INDIRECT COST,$	51.0	60972920.	60972920.	60972920.	60972920.	60972920.
PROF & OWNER COSTS,$	8.0	35039129.	35039129.	35039129.	35039129.	35039129.
CONTINGENCY COST,$	9.5	41608966.	41608966.	41608966.	41608966.	41608966.
SUB TOTAL,$	.0	575610136.	575610136.	575610136.	575610136.	575610136.
ESCALATION COST,$	6.5	158467778.	158467778.	158467778.	158467778.	158467778.
INTREST DURING CONST,$	10.0	191996608.	191996608.	191996608.	191996608.	191996608.
TOTAL CAPITALIZATION,$	.0	926074520.	926074520.	926074520.	926074520.	926074520.
COST OF ELEC-CAPITAL	25.0	14.21198	20.46525	25.58156	30.69787	35.52995
COST OF ELEC-FUEL	.0	8.33370	8.33370	8.33370	8.33370	8.33370
COST OF ELEC-OP & MAIN	.0	1.96351	1.96351	1.96351	1.96351	1.96351
TOTAL COST OF ELEC	.0	24.50319	30.76246	35.87877	40.99508	45.82715

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	437989124.	437989124.	437989124.	437989124.	437989124.
INDIRECT COST,$	51.0	60972920.	60972920.	60972920.	60972920.	60972920.
PROF & OWNER COSTS,$	8.0	35039129.	35039129.	35039129.	35039129.	35039129.
CONTINGENCY COST,$	9.5	41608966.	41608966.	41608966.	41608966.	41608966.
SUB TOTAL,$	.0	575610136.	575610136.	575610136.	575610136.	575610136.
ESCALATION COST,$	6.5	158467778.	158467778.	158467778.	158467778.	158467778.
INTREST DURING CONST,$	10.0	191996608.	191996608.	191996608.	191996608.	191996608.
TOTAL CAPITALIZATION,$	.0	926074520.	926074520.	926074520.	926074520.	926074520.
COST OF ELEC-CAPITAL	18.0	25.58156	25.58156	25.58156	25.58156	25.58156
COST OF ELEC-FUEL	.0	4.90218	8.33370	14.70653	24.51088	10.00044
COST OF ELEC-OP & MAIN	.0	1.96351	1.96351	1.96351	1.96351	1.96351
TOTAL COST OF ELEC	.0	32.44724	35.87877	42.25160	52.05595	37.54551

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	437989124.	437989124.	437989124.	437989124.	437989124.
INDIRECT COST,$	51.0	60972920.	60972920.	60972920.	60972920.	60972920.
PROF & OWNER COSTS,$	8.0	35039129.	35039129.	35039129.	35039129.	35039129.
CONTINGENCY COST,$	9.5	41608966.	41608966.	41608966.	41608966.	41608966.
SUB TOTAL,$	.0	575610136.	575610136.	575610136.	575610136.	575610136.
ESCALATION COST,$	6.5	158467778.	158467778.	158467778.	158467778.	158467778.
INTREST DURING CONST,$	10.0	191996608.	191996608.	191996608.	191996608.	191996608.
TOTAL CAPITALIZATION,$	.0	926074520.	926074520.	926074520.	926074520.	926074520.
COST OF ELEC-CAPITAL	18.0	138.56679	36.95114	33.25603	25.58156	20.78502
COST OF ELEC-FUEL	.0	8.33370	8.33370	8.33370	8.33370	8.33370
COST OF ELEC-OP & MAIN	.0	3.21857	2.12566	2.07483	1.96351	1.88890
TOTAL COST OF ELEC	.0	150.11906	47.41050	43.66456	35.87877	31.00761

Table A 8.3.6

RANKINE METAL VAPOR TOPPING-STEAM CYCLE

ACCOUNT NO	AUX POWER, MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	8.34881	16.09199	55.05127	13.08731
7	7.54857	13.57405	1463.94225	.00000
8	.00000	.00000	4.76623	.00000
14	.00000	.00000	87.19131	.00000
18	10.29180	18.50700	.00000	.00000
20	28.82114	51.82695	9.06275	.00000
TOTALS	55.61032	4.85939	1620.01379	13.08731

RANKINE METAL VAPOP TOPPING-STEAM CYCLE BASE CASE INPUT

NOMINAL POWER, MWE	1200.0000	NET POWER, MWE	1144.3897
NOM HEAT RATE, BTU/KW-HR	9349.3998	NET HEAT RATE, BTU/KW-HR	9804.3522
ST TURB HEAT RATE CHANGE	.9781		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	3.0000
NUMBER OF TUBES/SHELL	6985.9500	TUBE LENGTH, FT	69.5067
U, BTU/HR-FT2-F	608.8535	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	51.4000
OFF DESIGN PRES, IN HG A	2.4196	LP TURBINE BLADE LEN, IN	25.0000

1	1200.000	2	.000	3	.365	4	.000	5	6.500
6	715.300	7	3.500	8	33720000.000	9	3.000	10	1.000
11	1.000	12	298.600	13	1.000	14	4.000	15	1.000
16	2.000	17	198.000	18	3.000	19	5.000	20	3.000
21	.000	22	23950.000	23	.000	24	27300.000	25	.000
26	7500000.000	27	20000.000	28	20000.000	29	2600000.000	30	.600
31	1.000	32	1540.000	33	.000	34	1.000	35	1.000
36	4930000.000	37	1700.000	38	1.000	39	1.000	40	725000.000
41	166000.000	42	660000.000	43	15000.000	44	1250000.000	45	774000.000
46	1.000	47	.000	48	3.000	49	2.000	50	.000
51	.000	52	5.350						

1	8.000	2	.000	3	2200000.000	4	450000.000	5	.000
6	.000	7	1.000	8	4.000	9	8.000	10	4.000
11	4.000	12	2000.000	13	1300.000	14	4.000	15	1.000
16	1970000.000	17	.000	18	7100000.000	19	.000	20	3000000.000
21	.000	22	625000.000	23	90000.000	24	215000.000	25	.000
26	1820.000	27	630.000	28	310.000	29	104.000	30	450000.000
31	.000	32	665000.000	33	.000	34	4.000	35	4.000
36	2300000.000	37	.000	38	725000.000	39	110000.000	40	.000
41	.000	42	.000	43	1.000	44	.000	45	.000
46	.000	47	.000	48	.000	49	.000	50	.000
51	.000	52	1500000.000	53	.000	54	.000	55	.000
56	.000	57	.000	58	1.000	59	4.000	60	1.000
61	1.000	62	4.000	63	6200000.000	64	2000000.000	65	1300000.000
66	150000.000	67	800000.000	68	250000.000	69	1700000.000	70	400000.000
71	570000.000	72	86000.000	73	4.000	74	2000000.000	75	.000
76	1.000	77	1.000	78	250000.000	79	200000.000	80	2500000.000
81	2000000.000	82	.000	83	.000	84	.000	85	.000
86	.900	87	.000	88	.000	89	.000	90	.000
91	.000	92	.000	93	.000	94	.000	95	.000
96	.000	97	.000	98	.000	99	.000	100	.000

Table A 8.3.7

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO.49

ACCOUNT NO. & NAME.	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	187.0	1000.00	.00	187000.00	.00
1. 2 CLEARING LAND	ACRE	62.3	.00	600.00	.00	37396.26
1. 3 GRADING LAND	ACRE	187.0	.00	3000.00	.00	561000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.5	120000.00	70000.00	300000.00	175000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	396406.86	396406.86
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 = .883 ACCOUNT TOTAL,$					1458406.86	1719803.11
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	75150.0	.00	3.00	.00	225450.00
2. 2 PILING	FT	200400.0	6.50	8.50	1302600.00	1703400.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 = .898 ACCOUNT TOTAL,$					1302600.00	1928850.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	25050.0	70.00	80.00	1753500.00	2004000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 = 1.044 ACCOUNT TOTAL,$					1753500.00	2004000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	13.0	.00	.00	1995500.00	994500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	1130319.83	1515616.03
4. 3 SURFACE CONDENSER	FT2	381071.8	.00	.00	1737028.50	266750.29
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 = 2.123 ACCOUNT TOTAL,$					4862848.31	2776866.31
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	27300.0	650.00	175.00	17745000.00	4777500.00
5. 2 SILOS & BUNKERS	TPH	.0	1800.00	750.00	.00	.00
5. 3 CHIMNEY	FT	.0	.00	.00	.00	.00
5. 4 STRUCTURAL FEATURES	EACH	1.0	725000.00	166000.00	725000.00	166000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 5 = 6.507 ACCOUNT TOTAL,$					18470000.00	4943500.00
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	7500000.0	.16	.16	1200000.00	1200000.00
6. 2 ADMINSTRATION	FT2	20000.0	16.00	14.00	320000.00	280000.00
6. 3 WAREHOUSE & SHOP	FT2	20000.0	12.00	8.00	240000.00	160000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 = .945 ACCOUNT TOTAL,$					1760000.00	1640000.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	425.6	.00	.00	5921766.19	2517788.03
7. 2 DOLOMITE HAND. SYS	TPH	225.2	.00	.00	3002740.47	1385278.22
7. 3 FUEL OIL HAND. SYS	GAL	2600000.0	.00	.00	290836.01	227826.41
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 = 3.709 ACCOUNT TOTAL,$					9215342.62	4130892.66
FUEL PROCESSING						
8. 1 COAL DRYER & CRUSHER	TPH	.0	.00	.00	.00	.00
8. 2 CARBONIZERS	TPH	.0	.00	.00	.00	.00
8. 3 GASIFIERS	TPH	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 8 = .000 ACCOUNT TOTAL,$					.00	.00

Table A 8.3.7 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 43

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
FIRING SYSTEM						
9. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 9 = .000 ACCOUNT TOTAL,$					.00	.00
VAPOR GENERATOR (FIRED)						
10. 1 PRESSURIZE BOILER	EA	.0	.00	.00	.00	.00
10. 2 FLUID BED BOILER	EA	4.0	15168000.00	8531999.87	60672000.00	34127999.50
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =26.345 ACCOUNT TOTAL,$					60672000.00	34127999.50
ENERGY CONVERTER						
11. 1 STEAM TURBINE GENERATOR		1.0	19700000.00	1209394.25	19700000.00	1209394.25
11. 2 GAS TURBINE GENERATOR		4.0	6000000.00	1576000.00	24000000.00	6304000.00
11. 3 LIQUID METAL TURB-GEN		8.0	3000000.00	270000.00	24000000.00	2159999.97
11. 4 LIQUID METAL DRUM		4.0	590000.00	90000.00	2360000.00	360000.00
11. 5 LIQUID MET RECIRC PUMP		4.0	215000.00	17200.00	860000.00	68800.00
11. 6 LIQ MET HOT LEG PIPING		2000.0	2330.00	780.00	4660000.00	1560000.00
11. 7 LIQ MET COLD LEG PIPE		1300.0	310.00	104.00	403000.00	135200.00
11. 8 LIQ MET CONDENSATE PUMP		4.0	360000.00	28800.00	1440000.00	115200.00
11. 9 LIQ MET INVENTORY		1.0	640000.00	12800.00	640000.00	12800.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =25.008 ACCOUNT TOTAL,$					78063000.00	11925394.12
COUPLING HEAT EXCHANGER						
12. 1 L M COND-STEAM GEN	EA	4.0	1946000.00	834000.00	7784000.00	3336000.00
12. 2 HOT WELL TANK	EA	4.0	675000.00	110000.00	2700000.00	440000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = 3.963 ACCOUNT TOTAL,$					10484000.00	3776000.00
HEAT RECOVERY HEAT EXCH.						
13. 1 GAS-AIR RECUPERATOR	EA	.0	.00	.00	.00	.00
13. 2 ECONOMIZER	EA	.0	.00	.00	.00	.00
13. 3 GAS FEED WATER HEATER	EA	4.0	1042500.00	347500.00	4170000.00	1390000.00
13. 4 FEED WATER HEATER STRING		1.0	1720000.00	51600.00	1720000.00	51600.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = 2.037 ACCOUNT TOTAL,$					5890000.00	1441600.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	132.3	2500.00	700.00	330679.99	92590.40
14. 2 CONDENSATE POLISHING	KWE	826700.0	1.25	.30	1033374.98	248010.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .474 ACCOUNT TOTAL,$					1364054.97	340600.39
POWER CONDITIONING						
15. 1 STM TURB TRANSFORMER		1010411.1	.00	.00	1751257.39	35025.15
15. 2 MET VAP TURB TRANSFORMER		214133.3	.00	.00	4488381.25	700.50
15. 3 GAS TURB TRANSFORMER		242122.2	.00	.00	2407607.84	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 2.413 ACCOUNT TOTAL,$					8647246.37	35725.65

Table A 8.3.7 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO.49

ACCOUNT NO. & NAME.	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	785365.0	1.67	.10	1311559.53	78536.50
16. 2 OTHER PUMPS	KWE	684000.0	.88	.12	601920.00	82080.00
16. 3 MISC SERVICE SYS	KWE	1140000.0	1.17	.73	1333800.00	832199.99
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
16. 5 LIQ MET RECEIVING-PROC		1.0	6300000.00	2000000.00	6300000.00	2000000.00
16. 6 LIQ MET STORAGE TANK	EA	4.0	1300000.00	150000.00	5200000.00	600000.00
16. 7 LIQ MET IMPURITY MONITOR		1.0	800000.00	250000.00	800000.00	250000.00
16. 8 COVER GAS SYSTEM	EA	1.0	1700000.00	400000.00	1700000.00	400000.00
16. 9 LIQ MET DUMP TANK	EA	4.0	570000.00	86000.00	2280000.00	344000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 6.701 ACCOUNT TOTAL,$					19527279.50	4586816.44
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	1370.0	3000.00	1800.00	4110000.00	2466000.00
17. 2 HOT GAS PIPING	EA	4.0	1600000.00	.00	6400000.00	.00
17. 3 STEAM PIPING & FITTINGS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 3.606 ACCOUNT TOTAL,$					10510000.00	2466000.00
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		1140000.0	1.40	.17	1596000.00	193800.00
18. 2 SWITCHGEAR & MCC PAN	KWE	1140000.0	1.95	.45	2223000.00	513000.00
18. 3 CONDUIT,CABLES,TRAYS	FT	4930000.0	1.32	1.36	6507599.94	6704799.94
18. 4 ISOLATED PHASE BUS	FT	1700.0	510.00	450.00	867000.00	765000.00
18. 5 LIGHTING & COMMUN	KWE	1140000.0	.35	.43	399000.00	490200.00
18. 6 LM LEAK DETECTION SYS	EA	1.0	250000.00	200000.00	250000.00	200000.00
18. 7 LM TRACE HEATING SYSTEM		1.0	2500000.00	2000000.00	2500000.00	2000000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 7.006 ACCOUNT TOTAL,$					14342599.87	10866799.75
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	660000.00	15000.00	660000.00	15000.00
19. 2 OTHER CONTROLS	EACH	1.0	1250000.00	774000.00	1250000.00	774000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = .750 ACCOUNT TOTAL,$					1910000.00	789000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	40.9	2400835.16	600208.79	2400835.16	600208.79
20. 3 WET SLURRY	TPH	225.2	5715449.06	1428862.27	5715449.06	1428862.27
20. 4 ONSITE DISPOSAL	ACRE	746.0	5272.45	8081.34	3933406.16	6028918.81
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 5.588 ACCOUNT TOTAL,$					12049690.25	8057989.81
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	7752708.06	5039260.19	.00	.00
21. 2 SCRUBBER	KWE	.0	21.55	9.88	.00	.00
21. 3 MISC STEEL & DUCTS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 21 = .000 ACCOUNT TOTAL,$					.00	.00
TOTAL DIRECT COSTS,$					262282562.00	97557834.00

Table A 8.3.8

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.43

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	317503976.	340512835.	359840392.	400336096.	460159296.
INDIRECT COST,$	51.0	28162921.	39897471.	49754494.	70407303.	100917134.
PROF & OWNER COSTS,$	8.0	25400318.	27241031.	28787231.	32026887.	36812743.
CONTINGENCY COST,$	9.5	30162877.	32348725.	34184837.	38031929.	43715133.
SUB TOTAL,$	.0	401230088.	440000116.	472566948.	540802208.	641604288.
ESCALATION COST,$	6.5	110460252.	121133797.	130099576.	148885016.	176636234.
INTREST DURING CONST,$	10.0	133831583.	146763450.	157626222.	180386312.	214009168.
TOTAL CAPITALIZATION,$	.0	645521920.	707897360.	760292736.	870073536.	1032249688.
COST OF ELEC-CAPITAL	18.0	17.90084	19.63056	21.08353	24.12784	28.62511
COST OF ELEC-FUEL	.0	6.84663	6.84663	6.84663	6.84663	6.84663
COST OF ELEC-OP & MAIN	.0	1.67201	1.67201	1.67201	1.67201	1.67201
TOTAL COST OF ELEC	.0	26.41948	28.14920	29.60217	32.64648	37.14375

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	9.50	5.00	20.00
TOTAL DIRECT COSTS,$	.0	359840392.	359840392.	359840392.	359840392.	359840392.
INDIRECT COST,$	51.0	49754494.	49754494.	49754494.	49754494.	49754494.
PROF & OWNER COSTS,$	8.0	28787231.	28787231.	28787231.	28787231.	28787231.
CONTINGENCY COST,$	20.0	-17992019.	0.	34184837.	17992019.	71968078.
SUB TOTAL,$	.0	420390096.	438382112.	472566948.	456374128.	510350188.
ESCALATION COST,$	6.5	115735080.	120688354.	130099576.	125641628.	140501454.
INTREST DURING CONST,$	10.0	140222464.	146223760.	157626222.	152275054.	170228952.
TOTAL CAPITALIZATION,$	.0	676347640.	705294224.	760292736.	734240800.	821080576.
COST OF ELEC-CAPITAL	18.0	18.75566	19.55837	21.08353	20.36109	22.76922
COST OF ELEC-FUEL	.0	6.84663	6.84663	6.84663	6.84663	6.84663
COST OF ELEC-OP & MAIN	.0	1.67201	1.67201	1.67201	1.67201	1.67201
TOTAL COST OF ELEC	.0	27.27430	28.07701	29.60217	28.87973	31.28786

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	359840392.	359840392.	359840392.	359840392.	359840392.
INDIRECT COST,$	51.0	49754494.	49754494.	49754494.	49754494.	49754494.
PROF & OWNER COSTS,$	8.0	28787231.	28787231.	28787231.	28787231.	28787231.
CONTINGENCY COST,$	9.5	34184837.	34184837.	34184837.	34184837.	34184837.
SUB TOTAL,$	.0	472566948.	472566948.	472566948.	472566948.	472566948.
ESCALATION COST,$	.0	97657989.	130099576.	164092682.	211932152.	0.
INTREST DURING CONST,$	10.0	150499152.	157626222.	165029884.	175345882.	128637462.
TOTAL CAPITALIZATION,$	.0	720724080.	760292736.	801689504.	859844976.	601204408.
COST OF ELEC-CAPITAL	18.0	19.98626	21.08353	22.23149	23.84419	16.67188
COST OF ELEC-FUEL	.0	6.84663	6.84663	6.84663	6.84663	6.84663
COST OF ELEC-OP & MAIN	.0	1.67201	1.67201	1.67201	1.67201	1.67201
TOTAL COST OF ELEC	.0	28.50490	29.60217	30.75013	32.36283	25.19052

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	359840392.	359840392.	359840392.	359840392.	359840392.
INDIRECT COST,$	51.0	49754494.	49754494.	49754494.	49754494.	49754494.
PROF & OWNER COSTS,$	8.0	28787231.	28787231.	28787231.	28787231.	28787231.
CONTINGENCY COST,$	9.5	34184837.	34184837.	34184837.	34184837.	34184837.
SUB TOTAL,$	.0	472566948.	472566948.	472566948.	472566948.	472566948.
ESCALATION COST,$	6.5	130099576.	130099576.	130099576.	130099576.	130099576.
INTREST DURING CONST,$	15.0	90840785.	123583174.	157626222.	202075378.	248712416.
TOTAL CAPITALIZATION,$	.0	693507304.	726249688.	760292736.	804741896.	851378936.
COST OF ELEC-CAPITAL	18.0	19.23151	20.13949	21.08353	22.31614	23.60942
COST OF ELEC-FUEL	.0	6.84663	6.84663	6.84663	6.84663	6.84663
COST OF ELEC-OP & MAIN	.0	1.67201	1.67201	1.67201	1.67201	1.67201
TOTAL COST OF ELEC	.0	27.75015	28.65813	29.60217	30.83478	32.12806

Table A 8.3.8 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.43

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	359840392.	359840392.	359840392.	359840392.	359840392.
INDIRECT COST,$	51.0	49754494.	49754494.	49754494.	49754494.	49754494.
PROF & OWNER COSTS,$	8.0	28787231.	28787231.	28787231.	28787231.	28787231.
CONTINGENCY COST,$	9.5	34184837.	34184837.	34184837.	34184837.	34184837.
SUB TOTAL,$	.0	472566948.	472566948.	472566948.	472566948.	472566948.
ESCALATION COST,$	6.5	130099576.	130099576.	130099576.	130099576.	130099576.
INTREST DURING CONST,$	10.0	157626222.	157626222.	157626222.	157626222.	157626222.
TOTAL CAPITALIZATION,$	.0	760292736.	760292736.	760292736.	760292736.	760292736.
COST OF ELEC-CAPITAL	25.0	11.71307	16.86682	21.08353	25.30023	29.28268
COST OF ELEC-FUEL	.0	6.84663	6.84663	6.84663	6.84663	6.84663
COST OF ELEC-OP & MAIN	.0	1.67201	1.67201	1.67201	1.67201	1.67201
TOTAL COST OF ELEC	.0	20.23171	25.38546	29.60217	33.81887	37.80132

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	359840392.	359840392.	359840392.	359840392.	359840392.
INDIRECT COST,$	51.0	49754494.	49754494.	49754494.	49754494.	49754494.
PROF & OWNER COSTS,$	8.0	28787231.	28787231.	28787231.	28787231.	28787231.
CONTINGENCY COST,$	9.5	34184837.	34184837.	34184837.	34184837.	34184837.
SUB TOTAL,$	.0	472566948.	472566948.	472566948.	472566948.	472566948.
ESCALATION COST,$	6.5	130099576.	130099576.	130099576.	130099576.	130099576.
INTREST DURING CONST,$	10.0	157626222.	157626222.	157626222.	157626222.	157626222.
TOTAL CAPITALIZATION,$	.0	760292736.	760292736.	760292736.	760292736.	760292736.
COST OF ELEC-CAPITAL	18.0	21.08353	21.08353	21.08353	21.08353	21.08353
COST OF ELEC-FUEL	.0	4.02743	6.84663	12.08230	20.13716	8.21595
COST OF ELEC-OP & MAIN	.0	1.67201	1.67201	1.67201	1.67201	1.67201
TOTAL COST OF ELEC	.0	26.78297	29.60217	34.83783	42.89269	30.97149

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	359840392.	359840392.	359840392.	359840392.	359840392.
INDIRECT COST,$	51.0	49754494.	49754494.	49754494.	49754494.	49754494.
PROF & OWNER COSTS,$	8.0	28787231.	28787231.	28787231.	28787231.	28787231.
CONTINGENCY COST,$	9.5	34184837.	34184837.	34184837.	34184837.	34184837.
SUB TOTAL,$	.0	472566948.	472566948.	472566948.	472566948.	472566948.
ESCALATION COST,$	6.5	130099576.	130099576.	130099576.	130099576.	130099576.
INTREST DURING CONST,$	10.0	157626222.	157626222.	157626222.	157626222.	157626222.
TOTAL CAPITALIZATION,$	.0	760292736.	760292736.	760292736.	760292736.	760292736.
COST OF ELEC-CAPITAL	18.0	114.20244	30.45398	27.40858	21.08353	17.13037
COST OF ELEC-FUEL	.0	6.84663	6.84663	6.84663	6.84663	6.84663
COST OF ELEC-OP & MAIN	.0	2.92707	1.83416	1.78333	1.67201	1.59740
TOTAL COST OF ELEC	.0	123.97614	39.13478	36.03855	29.60217	25.57440

Table A 8.3.9

RANKINE METAL VAPOR TOPPING-STEAM CYCLE

ACCOUNT NO	AUX POWER, MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	8.34353	14.89792	55.00832	13.08170
7	6.21173	10.34734	1264.67934	.00000
8	10.13970	16.99042	.00000	.00000
14	.00000	.00000	14.30682	.00000
18	10.96020	18.25723	.00000	.00000
20	23.71694	39.50709	7.45775	.00000
TOTALS	60.03210	5.26612	1281.45271	13.08170

RANKINE METAL VAPOR TOPPING-STEAM CYCLE BASE CASE INPUT

NOMINAL POWER, MWE	1200.0000	NET POWER, MWE	1139.9679
NOM HEAT RATE, BTU/KW-HR	7651.9056	NET HEAT RATE, BTU/KW-HR	8054.8641
ST TURB HEAT RATE CHANGE	.3780		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	3.0000
NUMBER OF TUBES/SHELL	6980.5634	TUBE LENGTH, FT	69.5067
U, BTU/HR-FT2-F	603.3535	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	51.4000
OFF DESIGN PRES, IN HG A	2.4175	LP TURBINE BLADE LEN, IN	25.0000

1	1200.000	2	.000	3	.446	4	.000	5	6.500
6	825.700	7	3.500	8	3369400000.000	9	3.000	10	1.000
11	1.000	12	198.100	13	1.000	14	.000	15	.000
16	2.000	17	187.000	18	3.000	19	5.000	20	2.500
21	.000	22	25050.000	23	.000	24	27300.000	25	.000
26	7500000.000	27	20000.000	28	20000.000	29	2600000.000	30	.600
31	1.000	32	1370.000	33	.000	34	1.000	35	1.000
36	4930000.000	37	1700.000	38	1.000	39	1.000	40	725000.000
41	166000.000	42	660000.000	43	15000.000	44	125000.000	45	774000.000
46	.000	47	.000	48	3.000	49	2.000	50	.000
51	.000	52	5.350						

1	.000	2	4.000	3	.000	4	.000	5	23700000.000
6	.000	7	1.000	8	4.000	9	8.000	10	4.000
11	4.000	12	2000.000	13	1300.000	14	4.000	15	1.000
16	19700000.000	17	.000	18	6000000.000	19	.000	20	3000000.000
21	.000	22	590000.000	23	90000.000	24	215000.000	25	.000
26	2330.000	27	780.000	28	310.000	29	104.000	30	360000.000
31	.000	32	640000.000	33	.000	34	4.000	35	4.000
36	2780000.000	37	.000	38	575000.000	39	110000.000	40	.000
41	.000	42	4.000	43	1.000	44	.000	45	.000
46	.000	47	.000	48	.000	49	.000	50	1390000.000
51	.000	52	1720000.000	53	.000	54	.000	55	.000
56	.000	57	.000	58	1.000	59	4.000	60	1.000
61	1.000	62	4.000	63	6300000.000	64	2000000.000	65	1300000.000
66	150000.000	67	800000.000	68	250000.000	69	1700000.000	70	400000.000
71	570000.000	72	86000.000	73	4.000	74	1600000.000	75	.000
76	1.000	77	1.000	78	250000.000	79	200000.000	80	2500000.000
81	2000000.000	82	.000	83	.000	84	.000	85	.000
86	.900	87	.000	88	.000	89	.000	90	1.000
91	.000	92	.000	93	.000	94	.000	95	.000
96	.000	97	.000	98	.000	99	.000	100	.000

Table A 8.3.10

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO.46

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	187.0	1000.00	.00	187000.00	.00
1. 2 CLEARING LAND	ACRE	62.3	.00	600.00	.00	37396.26
1. 3 GRADING LAND	ACRE	187.0	.00	3000.00	.00	561000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.5	120000.00	70000.00	300000.00	175000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	396406.86	396406.86
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 =			.814 ACCOUNT TOTAL,$		1458406.86	1719803.11
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	75150.0	.00	3.00	.00	225450.00
2. 2 PILING	FT	200400.0	6.50	8.50	1302600.00	1703400.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 =			.827 ACCOUNT TOTAL,$		1302600.00	1928850.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	25050.0	70.00	80.00	1753500.00	2004000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 =			.962 ACCOUNT TOTAL,$		1753500.00	2004000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	14.0	.00	.00	2149000.00	1071000.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	1215394.06	1629689.83
4. 3 SURFACE CONDENSER	FT2	409753.4	.00	.00	1837454.39	286827.41
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 =			2.096 ACCOUNT TOTAL,$		5201848.44	2987517.22
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	27300.0	650.00	175.00	17745000.00	4777500.00
5. 2 SILOS & BUNKERS	TPH	.0	1800.00	750.00	.00	.00
5. 3 CHIMNEY	FT	.0	.00	.00	.00	.00
5. 4 STRUCTURAL FEATURES	EACH	1.0	725000.00	166000.00	725000.00	166000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 5 =			5.994 ACCOUNT TOTAL,$		18470000.00	4943500.00
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	7500000.0	.16	.16	1200000.00	1200000.00
6. 2 ADMINSTRATION	FT2	20000.0	16.00	14.00	320000.00	280000.00
6. 3 WAREHOUSE & SHOP	FT2	20000.0	12.00	8.00	240000.00	160000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 =			.870 ACCOUNT TOTAL,$		1760000.00	1640000.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	419.9	.00	.00	5850870.50	2491911.41
7. 2 DOLOMITE HAND. SYS	TPH	222.2	.00	.00	2966731.44	1371040.98
7. 3 FUEL OIL HAND. SYS	GAL	2600000.0	.00	.00	290836.01	227826.41
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 =			3.379 ACCOUNT TOTAL,$		9108437.87	4090778.78
FUEL PROCESSING						
8. 1 COAL DRYER & CRUSHER	TPH	.0	.00	.00	.00	.00
8. 2 CARBONIZERS	TPH	.0	.00	.00	.00	.00
8. 3 GASIFIERS	TPH	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 8 =			.000 ACCOUNT TOTAL,$		.00	.00

Table A 8.3.10 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO.46

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
FIRING SYSTEM						
9. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 9 = .000 ACCOUNT TOTAL,$					.00	.00
VAPOR GENERATOR (FIRED)						
10. 1 PRESSURIZE BOILER	EA	.0	.00	.00	.00	.00
10. 2 FLUID BED BOILER	EA	4.0	15155200.00	8524799.87	60620800.00	34099199.50
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =24.248 ACCOUNT TOTAL,$					60620800.00	34099199.50
ENERGY CONVERTER						
11. 1 STEAM TURBINE GENERATOR		1.0	19700000.00	1215823.09	19700000.00	1215823.09
11. 2 GAS TURBINE GENERATOR		4.0	5900000.00	1576000.00	23600000.00	6304000.00
11. 3 LIQUID METAL TURB-GEN		8.0	2000000.00	180000.00	16000000.00	1439999.98
11. 4 LIQUID METAL DRUM		4.0	1180000.00	1360000.00	4720000.00	5440000.00
11. 5 LIQUID MET RECIRC PUMP		4.0	235000.00	18800.00	940000.00	75200.00
11. 6 LIQ MET HOT LEG PIPING		2000.0	2330.00	780.00	4660000.00	1560000.00
11. 7 LIQ MET COLD LEG PIPE		1300.0	367.00	124.00	477100.00	161200.00
11. 8 LIQ MET CONDENSATE PUMP		4.0	495000.00	39600.00	1980000.00	158400.00
11. 9 LIQ MET INVENTORY		1.0	28636000.00	572720.00	28636000.00	572720.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =30.115 ACCOUNT TOTAL,$					100713100.00	16927343.00
COUPLING HEAT EXCHANGER						
12. 1 L M COND-STEAM GEN	EA	4.0	1911000.00	819000.00	7644000.00	3276000.00
12. 2 HOT WELL TANK	EA	4.0	750000.00	125000.00	3000000.00	500000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = 3.691 ACCOUNT TOTAL,$					10644000.00	3776000.00
HEAT RECOVERY HEAT EXCH.						
13. 1 GAS-AIR RECUPERATOR	EA	.0	.00	.00	.00	.00
13. 2 ECONOMIZER	EA	.0	.00	.00	.00	.00
13. 3 GAS FEED WATER HEATER	EA	4.0	1027500.00	342500.00	4110000.00	1370000.00
13. 4 FEED WATER HEATER STRING		1.0	1720000.00	51600.00	1720000.00	51600.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = 1.856 ACCOUNT TOTAL,$					5830000.00	1421600.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	129.7	2500.00	700.00	324239.99	90787.20
14. 2 CONDENSATE POLISHING	KWE	810600.0	1.25	.30	1013249.98	243180.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .428 ACCOUNT TOTAL,$					1337489.97	333967.20
POWER CONDITIONING						
15. 1 STM TURB TRANSFORMER		990733.3	.00	.00	1727447.28	34548.95
15. 2 MET VAP TURB TRANSFORMER		237294.5	.00	.00	4516406.19	690.98
15. 3 GAS TURB TRANSFORMER		238638.9	.00	.00	2403333.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 2.223 ACCOUNT TOTAL,$					8647246.37	35239.92

Table A 8.3.10 Continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO.46

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	770070.0	1.67	.10	1286016.87	77007.00
16. 2 OTHER PUMPS	KWE	684000.0	.33	.12	601920.00	82080.00
16. 3 MISC SERVICE SYS	KWE	1140000.0	1.17	.73	1333800.00	832199.99
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
16. 5 LIQ MET RECEIVING-PROC		1.0	6200000.00	2000000.00	6200000.00	2000000.00
16. 6 LIQ MET STORAGE TANK	EA	4.0	1710000.00	285000.00	6840000.00	1140000.00
16. 7 LIQ MET IMPURITY MONITOR		1.0	800000.00	250000.00	800000.00	250000.00
16. 8 COVER GAS SYSTEM	EA	1.0	1700000.00	400000.00	1700000.00	400000.00
16. 9 LIQ MET DUMP TANK	EA	4.0	770000.00	125000.00	3080000.00	500000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 =			6.943	ACCOUNT TOTAL,$	21841736.75	5281286.94
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	1370.0	3000.00	1800.00	4110000.00	2466000.00
17. 2 HOT GAS PIPING	EA	4.0	1600000.00	.00	6400000.00	.00
17. 3 STEAM PIPING & FITTINGS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 =			3.322	ACCOUNT TOTAL,$	10510000.00	2466000.00
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		1140000.0	1.40	.17	1596000.00	193800.00
18. 2 SWITCHGEAR & MCC PAN	KWE	1140000.0	1.95	.45	2223000.00	513000.00
18. 3 CONDUIT,CABLES,TRAYS	FT	4930000.0	1.32	1.36	6507599.94	6704799.94
18. 4 ISOLATED PHASE BUS	FT	1700.0	510.00	450.00	867000.00	765000.00
18. 5 LIGHTING & COMMUN	KWE	1140000.0	.35	.43	399000.00	490200.00
18. 6 LM LEAK DETECTION SYS	EA	1.0	250000.00	200000.00	250000.00	200000.00
18. 7 LM TRACE HEATING SYSTEM		1.0	2500000.00	2000000.00	2500000.00	2000000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 =			6.453	ACCOUNT TOTAL,$	14342599.87	10866799.75
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	660000.00	15000.00	660000.00	15000.00
19. 2 OTHER CONTROLS	EACH	1.0	1250000.00	774000.00	1250000.00	774000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 =			.691	ACCOUNT TOTAL,$	1910000.00	789000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	40.3	2375345.91	593836.48	2375345.91	593836.48
20. 3 WET SLURRY	TPH	222.2	5639580.31	1409895.08	5639580.31	1409895.08
20. 4 ONSITE DISPOSAL	ACRE	736.1	5286.89	8101.55	3891820.72	5963765.56
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 =			5.088	ACCOUNT TOTAL,$	11906746.87	7967497.06
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	7672318.81	4987007.19	.00	.00
21. 2 SCRUBBER	KWE	.0	21.61	9.91	.00	.00
21. 3 MISC STEEL & DUCTS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 21 =			.000	ACCOUNT TOTAL,$	.00	.00
TOTAL DIRECT COSTS,$					287358564.00	103278379.00

Table A 8.3.11

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.46

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	345818020.	370176128.	390636940.	433507212.	496838288.
INDIRECT COST,$	51.0	29814324.	42236958.	52671972.	74535810.	106834659.
PROF & OWNER COSTS,$	8.0	27665441.	29614090.	31250955.	34680576.	39747063.
CONTINGENCY COST,$	9.5	32852712.	35166732.	37110509.	41183185.	47199637.
SUB TOTAL,$	.0	436150488.	477193904.	511670372.	583906776.	690619637.
ESCALATION COST,$	6.5	120073979.	131373396.	140864906.	160751878.	190130354.
INTREST DURING CONST,$	10.0	145479394.	159169558.	170669294.	194763978.	230358394.
TOTAL CAPITALIZATION,$	.0	701703856.	767736848.	823204560.	939422624.	1111108368.
COST OF ELEC-CAPITAL	18.0	19.45962	21.29084	22.82907	26.05202	30.81321
COST OF ELEC-FUEL	.0	6.75603	6.75603	6.75603	6.75603	6.75603
COST OF ELEC-OP & MAIN	.0	1.66133	1.66133	1.66133	1.66133	1.66133
TOTAL COST OF ELEC	.0	27.87698	29.70820	31.24643	34.46938	39.23056

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	9.50	5.00	20.00
TOTAL DIRECT COSTS,$	.0	390636940.	390636940.	390636940.	390636940.	390636940.
INDIRECT COST,$	51.0	52671972.	52671972.	52671972.	52671972.	52671972.
PROF & OWNER COSTS,$	8.0	31250955.	31250955.	31250955.	31250955.	31250955.
CONTINGENCY COST,$	20.0	-19531847.	0.	37110509.	19531847.	78127387.
SUB TOTAL,$	.0	455028020.	474559864.	511670372.	494091708.	552687248.
ESCALATION COST,$	6.5	125271039.	130648234.	140864906.	136025428.	152157016.
INTREST DURING CONST,$	10.0	151776056.	158290964.	170669294.	164805874.	184350604.
TOTAL CAPITALIZATION,$	.0	732075112.	763499056.	823204560.	794923008.	889194864.
COST OF ELEC-CAPITAL	18.0	20.30187	21.17332	22.82907	22.04477	24.65911
COST OF ELEC-FUEL	.0	5.75603	6.75603	6.75603	6.75603	6.75603
COST OF ELEC-OP & MAIN	.0	1.66133	1.66133	1.66133	1.66133	1.66133
TOTAL COST OF ELEC	.0	28.71923	29.59068	31.24643	30.46212	33.07647

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	390636940.	390636940.	390636940.	390636940.	390636940.
INDIRECT COST,$	51.0	52671972.	52671972.	52671972.	52671972.	52671972.
PROF & OWNER COSTS,$	8.0	31250955.	31250955.	31250955.	31250955.	31250955.
CONTINGENCY COST,$	9.5	37110509.	37110509.	37110509.	37110509.	37110509.
SUB TOTAL,$	.0	511670372.	511670372.	511670372.	511670372.	511670372.
ESCALATION COST,$	.0	105738876.	140864906.	177670834.	229468870.	0.
INTREST DURING CONST,$	10.0	162952482.	170669294.	178685586.	189855202.	139281806.
TOTAL CAPITALIZATION,$	.0	780361728.	823204560.	868026784.	930994440.	650952176.
COST OF ELEC-CAPITAL	18.0	21.64095	22.82907	24.07208	25.81829	18.05218
COST OF ELEC-FUEL	.0	6.75603	6.75603	6.75603	6.75603	6.75603
COST OF ELEC-OP & MAIN	.0	1.66133	1.66133	1.66133	1.66133	1.66133
TOTAL COST OF ELEC	.0	30.05831	31.24643	32.48943	34.23565	26.46953

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	390636940.	390636940.	390636940.	390636940.	390636940.
INDIRECT COST,$	51.0	52671972.	52671972.	52671972.	52671972.	52671972.
PROF & OWNER COSTS,$	8.0	31250955.	31250955.	31250955.	31250955.	31250955.
CONTINGENCY COST,$	9.5	37110509.	37110509.	37110509.	37110509.	37110503.
SUB TOTAL,$	.0	511670372.	511670372.	511670372.	511670372.	511670372.
ESCALATION COST,$	6.5	140864906.	140864906.	140864905.	140864906.	140864906.
INTREST DURING CONST,$	15.0	98357573.	133809291.	170669294.	218796478.	269292584.
TOTAL CAPITALIZATION,$	.0	750892840.	786344560.	823204560.	871331744.	921827856.
COST OF ELEC-CAPITAL	18.0	20.82373	21.80687	22.82907	24.16373	25.56409
COST OF ELEC-FUEL	.0	6.75603	6.75503	6.75603	6.75603	6.75603
COST OF ELEC-OP & MAIN	.0	1.66133	1.66133	1.66133	1.66133	1.66133
TOTAL COST OF ELEC	.0	29.24108	30.22423	31.24643	32.58109	33.98144

Table A 8.3.11 continued

RANKINE METAL VAPOR TOPPING-STEAM CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.46

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	390636940.	390636940.	390636940.	390636940.	390636940.
INDIRECT COST,$	51.0	52671972.	52671972.	52671972.	52671972.	52671972.
PROF & OWNER COSTS,$	8.0	31250955.	31250955.	31250955.	31250955.	31250955.
CONTINGENCY COST,$	9.5	37110509.	37110509.	37110509.	37110509.	37110509.
SUB TOTAL,$	.0	511670372.	511670372.	511670372.	511670372.	511670372.
ESCALATION COST,$	6.5	140864906.	140864906.	140864906.	140864906.	140864906.
INTREST DURING CONST,$	10.0	170669294.	170669294.	170669294.	170669294.	170669294.
TOTAL CAPITALIZATION,$	.0	823204560.	823204560.	823204560.	823204560.	823204560.
COST OF ELEC-CAPITAL	25.0	12.68282	18.26326	22.82907	27.39488	31.70704
COST OF ELEC-FUEL	.0	6.75603	6.75603	6.75603	6.75603	6.75603
COST OF ELEC-OP & MAIN	.0	1.66133	1.66133	1.66133	1.66133	1.66133
TOTAL COST OF ELEC	.0	21.10017	26.68061	31.24643	35.81224	40.12440

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	390636940.	390636940.	390636940.	390636940.	390636940.
INDIRECT COST,$	51.0	52671972.	52671972.	52671972.	52671972.	52671972.
PROF & OWNER COSTS,$	8.0	31250955.	31250955.	31250955.	31250955.	31250955.
CONTINGENCY COST,$	9.5	37110509.	37110509.	37110509.	37110509.	37110509.
SUB TOTAL,$	.0	511670372.	511670372.	511670372.	511670372.	511670372.
ESCALATION COST,$	6.5	140864906.	140864906.	140864906.	140864906.	140864906.
INTREST DURING CONST,$	10.0	170669294.	170669294.	170669294.	170669294.	170669294.
TOTAL CAPITALIZATION,$	.0	823204560.	823204560.	823204560.	823204560.	823204560.
COST OF ELEC-CAPITAL	18.0	22.82907	22.82907	22.82907	22.82907	22.82907
COST OF ELEC-FUEL	.0	3.97414	6.75603	11.92241	19.87068	8.10724
COST OF ELEC-OP & MAIN	.0	1.66133	1.66133	1.66133	1.66133	1.66133
TOTAL COST OF ELEC	.0	28.46453	31.24643	36.41280	44.36107	32.59763

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	390636940.	390636940.	390636940.	390636940.	390636940.
INDIRECT COST,$	51.0	52671972.	52671972.	52671972.	52671972.	52671972.
PROF & OWNER COSTS,$	8.0	31250955.	31250955.	31250955.	31250955.	31250955.
CONTINGENCY COST,$	9.5	37110509.	37110509.	37110509.	37110509.	37110509.
SUB TOTAL,$	.0	511670372.	511670372.	511670372.	511670372.	511670372.
ESCALATION COST,$	6.5	140864906.	140864906.	140864906.	140864906.	140864906.
INTREST DURING CONST,$	10.0	170669294.	170669294.	170669294.	170669294.	170669294.
TOTAL CAPITALIZATION,$	.0	823204560.	823204560.	823204560.	823204560.	823204560.
COST OF ELEC-CAPITAL	18.0	123.65747	32.97532	29.67779	22.82907	18.54862
COST OF ELEC-FUEL	.0	6.75603	6.75603	6.75603	6.75603	6.75603
COST OF ELEC-OP & MAIN	.0	2.91639	1.82348	1.77265	1.66133	1.58672
TOTAL COST OF ELEC	.0	133.32989	41.55483	38.20647	31.24643	26.89137

Table A 8.3.12

RANKINE METAL VAPOR TOPPING-STEAM CYCLE

ACCOUNT NO	AUX POWER,MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	9.62017	16.01241	59.14910	14.02289
7	6.12927	10.20194	1188.66802	.00000
8	10.06431	16.75166	.00000	.00000
14	.00000	.00000	14.02819	.00000
18	10.86360	18.08205	.00000	.00000
20	23.40211	38.95193	7.35876	.00000
TOTALS	60.07946	5.27050	1269.22404	14.02289

RANKINE METAL VAPOR TOPPING-STEAM CYCLE BASE CASE INPUT

NOMINAL POWER, MWE	1200.0000	NET POWER, MWE	1139.9205
NOM HEAT RATE, BTU/KW-HR	7550.3316	NET HEAT RATE, BTU/KW-HR	7948.2714
ST TURB HEAT RATE CHANGE	.9781		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	3.0000
NUMBER OF TUBES/SHELL	7505.9598	TUBE LENGTH, FT	69.5067
U, BTU/HR-FT2-F	608.3535	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	51.4000
OFF DESIGN PRES, IN HG A	2.4235	LP TURBINE BLADE LEN, IN	25.0000

1	1200.000	2	.000	3	.452	4	.000	5	6.500
6	810.600	7	3.500	8	3623000000.000	9	3.000	10	1.000
11	1.000	12	195.250	13	1.000	14	.000	15	.000
16	2.000	17	187.000	18	3.000	19	5.000	20	2.500
21	.000	22	25050.000	23	.000	24	27300.000	25	.000
26	7500000.000	27	20000.000	28	20000.000	29	2600000.000	30	.600
31	1.000	32	1370.000	33	.000	34	1.000	35	1.000
36	4930000.000	37	1700.000	38	1.000	39	1.000	40	725000.000
41	166000.000	42	660000.000	43	15000.000	44	1250000.000	45	774000.000
46	.000	47	.000	43	3.000	49	2.000	50	.000
51	.000	52	5.350						

1	.000	2	4.000	3	.000	4	.000	5	23680000.000
6	.000	7	1.000	8	4.000	9	8.000	10	4.000
11	4.000	12	2000.000	13	1300.000	14	4.000	15	1.000
16	19700000.000	17	.000	18	5900000.000	19	.000	20	2000000.000
21	.000	22	1180000.000	23	1350000.000	24	235000.000	25	.000
26	2330.000	27	780.000	28	367.000	29	124.000	30	495000.000
31	.000	32	28636000.000	33	.000	34	4.000	35	4.000
36	2730000.000	37	.000	38	750000.000	39	125000.000	40	.000
41	.000	42	4.000	43	1.000	44	.000	45	.000
46	.000	47	.000	48	.000	49	.000	50	1370000.000
51	.000	52	1720000.000	53	.000	54	.000	55	.000
56	.000	57	.000	58	1.000	59	4.000	60	1.000
61	1.000	62	4.000	63	6200000.000	64	2000000.000	65	1710000.000
66	285000.000	67	800000.000	68	250000.000	69	1700000.000	70	400000.000
71	770000.000	72	125000.000	73	4.000	74	1600000.000	75	.000
76	1.000	77	1.000	78	250000.000	79	200000.000	80	250000.000
81	2000000.000	82	.000	83	.000	84	.000	85	.000
86	.900	87	.000	88	.000	89	.000	90	1.000
91	.000	92	.000	93	.000	94	.000	95	.000
96	.000	97	.000	98	.000	99	.000	100	.000

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