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Volume VI – CLOSED-CYCLE GAS TURBINE SYSTEMS

by
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16 Abstract

Both recuperated and bottomed closed cycle gas turbine systems were studied. All systems used a pressurizing gas turbine coupled with a pressurized furnace to heat the helium for the closed cycle gas turbine. Steam and organic vapors are used as Rankine bottoming fluids. Although plant efficiencies of over 40% are calculated for some plants, the resultant cost of electricity was found to be 8.75 mills/MJ (31.5 mills/kWh). These plants do not appear practical for coal or oil fired plants.

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Others contributing to the concept study were:

- R. G. Glenn, who prepared the turbine island arrangement drawings and the gas turbine engine cross sectional drawings.
- W. K. Fentress, who calculated the thermodynamic efficiency of a large majority of the parametric points and assisted in selected heat exchanger price calculations.
- W. F. Stahl, who decided upon the parametric points to be evaluated, calculated the efficiencies of the organic fluid bottoming turbines and generated much of the heat exchanger pricing.
- T. J. Fagan and J. M. Makiel of the Westinghouse Research Laboratories rough sized the required coupling heat exchangers.
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SUMMARY

Closed-cycle gas turbine systems include both recuperated and combined cycles. Both systems employ a pressurized furnace to heat the helium and as such required a pressurizing system which includes a conventional gas turbine-generator (pump-up turbine).

The recuperated system uses a pump-up turbine with an inlet temperature of 1478, 1200 or 866°K (2200, 1700 or 1100°F). The two lower temperatures are compatible with direct fluidized bed combustion of coal. Helium turbine inlet temperatures of 922, 1089, and 1255°K (1200, 1500 and 1800°F) with pressure ratios of 2, 2.5, 3 and 4 are considered.

The helium compressor discharge pressure is fixed at 6.895 MPa (1000 psi) with variations of 3.448 and 13.79 MPa (500 and 2000 psi). Values of recuperator effectiveness of 80, 90 and 95% are assumed for both the pump-up and helium turbine exhausts. Clean distillate fuel is used for the major part of the study but several cases with direct coal firing are considered. A thermodynamic efficiency of 38% is found for the 1255°K (1800°F) helium turbine inlet temperature with 90% effective recuperators using distillate as fuel. A 4.5 point increase in efficiency at the 1089°K (1500°F) helium turbine inlet temperature is observed as the recuperator effectiveness is increased from 80 to 95%.

The combined closed-cycle gas turbine system uses pump-up and helium gas turbine engines similar to those used in the recuperated cycle. The recuperators are replaced by heat recovery vapor generators. Heat from both the pump-up and helium turbine exhausts is used to heat the bottoming fluid. The major part of the study uses steam as the bottoming fluid but R-12, methylamine and sulfur dioxide are also included. An efficiency of 40.9% is obtained with steam bottoming and 43.1% with methylamine.

The high cost of the high temperature gas to gas heat exchangers results in high plant capital costs, typically $700/kW for the coal burning plants and $500/kW for those burning distillate. Notwithstanding this, the coal fired plants show a cost of electricity as low as 8.75 mills/MJ (31.5 mills/kWh) for the combined system with a steam bottomer compared to 10.06 mills/MJ (36.2 mills/kWh) for the distillate burning system. The cost of electricity for the recuperated systems is about 0.56 mills/MJ (2 mills/kWh higher).

Although the potential cycle efficiencies are high enough to be interesting, the complexity of the cycle, high cost of heat exchange surface and the resultant cost of electricity mitigate against externally fired closed-cycle gas turbine systems.

7. CLOSED-CYCLE GAS TURBINE SYSTEMS

7.1 State of the Art

7.1.1 Closed-Cycle Plant Installations

Closed gas turbine cycles have been studied since the mid-1930s when they were first proposed by Professor Ackeret and Dr. Keller. Since then, a few noteworthy closed-cycle power plants have been built and operated. A combination electricity and heat production plant at Spittelau, Vienna (Reference 7.1) has been in operation since 1971. This plant, rated at 30 MWe, utilizes a closed loop with air as the working medium and is fossil-fuel fired. A larger output combined electricity/heat plant (Reference 7.2) has been commissioned recently at Oberhausen, Germany. This unit, which is natural-gas fired, is particularly interesting because it employs helium as its working fluid. The Oberhausen plant is rated at approximately 50 MW of heat output in addition to the nominal 50 MW electrical output. Major cycle parameters of the Spittelau plant include a turbine inlet temperature of 991°K (1325°F) and a compressor pressure ratio of 5.7 to 1. Thermal efficiency with respect to electrical output is approximately 30%. The corresponding data for the Oberhausen closed-cycle helium plant read as follows: turbine inlet temperatures of 1023°K (1382°F), a compressor pressure ratio 2.7 to 1, and a plant thermal efficiency of 31.3%.

7.1.2 Areas of Concern: Heat Exchangers and Increased Turbine Inlet Temperature

There are two principal areas of concern regarding the widespread commercialization of closed-cycle plants. First, heat is added to the cycle by means of a surface heat exchanger which adds considerable expense to the overall capital cost of such a plant and limit helium turbine inlet temperatures. In the above-cited examples, some of this higher capital cost burden is ameliorated by the recovery and utilization of otherwise wasted cycle reject heat. The second concern pertains to the potential means for achieving higher cycle top temperatures. Conventional open-cycle gas turbines have achieved higher cycle inlet temperatures by means of convection-cooled turbine blading. By comparison, heat transfer rates in high-pressure helium are large and may lead to excessive stress-inducing thermal gradients in cooled turbine blading. Economically acceptable high temperature heat exchanger materials are not currently available.

7.1.3 Organic Bottoming Cycle Considerations

As discussed in Subsection 5.1, organic bottoming fluids have potential advantages over steam in two areas. Certain organic fluids have a much lower turbine exhaust volumetric flow than does steam and may potentially require smaller, less expensive turbomachinery, as discussed more fully in Subsection 7.2. Further, it may be economically preferable to utilize lower heat-rejection temperatures (for higher efficiency) than are now the practice with steam plants, owing to the smaller low-pressure element size requirements. Also, organic fluid bottoming cycles may be more amenable to a better thermodynamic fit to the available heat rejection from a gas turbine topping cycle. Subsection 7.3 discusses this principle of thermodynamic fit with organic bottoming cycles more fully.

7.2 Description of Parametric Points to Be Investigated.

Two kinds of closed-cycle systems were investigated during Task I: the recuperated closed-cycle systems with recovery of closed Brayton-cycle reject heat via recuperation and the combined closed-cycle systems with recovery of closed Brayton-cycle reject heat by means of a steam or organic Rankine bottoming cycle. In nearly all cases of both recuperated and combined-cycle arrangements, a pressurized furnace system (listed as pump-up cycle for convenient reference and consisting essentially of an open-cycle gas turbine system with externally pressurized furnace combustor) is used to provide heat input to the closed Brayton cycle.

Parameters varied for the helium turbomachinery include the turbine inlet temperature, compressor pressure ratio, and compressor discharge pressure level. Three values of turbine inlet temperature have been selected: 922, 1089, and 1255°K (1200, 1500, and 1800°F). Pressure ratios have been varied from 1.5 to 1 to 4 to 1 for nonintercooled helium cycles and from 4 to 1 to 7 to 1 for the intercooled cases. The level of compressor discharge pressure has been set at 6.895 MPa (1000 psi) abs for nearly all cases. Consideration is given to two other levels [3.447 and 13.790 MPa (500 and 2000 psi) abs].

Recuperator effectiveness values of 0.80, 0.90, and 0.95 and recuperator total pressure drop ratios of 0.02, 0.04, and 0.06 were assumed for both the pump-up and helium recuperators. Any one calculation used the same value of effectiveness for both the helium and pump-up recuperators unless otherwise noted.

7.2.1 Parametric Point Descriptions of Recuperated Closed-Cycle Systems

Table 7.1 displays the parametric point selection for the recuperated closed-cycle system. The systems evaluated are grouped according to combustion gas temperatures exiting from the furnace which represents different proportions of heat transmitted to the helium. The first group, with 1478°K (2200°F) into the pump-up turbine, is used for perturbation of recuperator effectiveness, helium top temperature, and helium pressure ratio. Figure 7.1 illustrates the cycle arrangement for this group, and Figure 7.2 displays the thermodynamic relationships by means of a temperature entropy diagram. On the temperature entropy diagram, heat added by combustion is depicted as heating the air to high (of the order of stoichiometric) temperature. The air is then cooled as it gives up its heat to the helium in the closed cycle. Both the closed-loop and open-loop gas turbine systems utilize recuperation for exhaust heat recovery.

The second group has an intermediate pump-up turbine inlet temperature of 1200°K (1700°F), corresponding to that in a projected fluid bed burning coal. The helium cycle parameters are set at the mean values

TABLE 7.1–CLOSED CYCLES - RECUPERATED

	Helium Cycle									Pump-Up Cycle							
	Turbine Inlet Temp., °F	Compressor Pressure Ratio	Compressor Outlet Pressure, Psia	Recuperator		Helium Heater $\frac{\Delta p}{p}$	Coolers			Turbine Inlet Temp, °F	Compressor Pressure Ratio	Recuperator		Comb	Fuel	Furnace Type	Heat Rejection
				Effectiveness	$\frac{\Delta p}{p}$		Cooler Approach ΔT, °F	Precooler Δp/p	Intercooler Δp/p			Effectiveness	$\frac{\Delta p}{p}$	$\frac{\Delta p}{p}$			
High Combustor Outlet Temperature	1200, 1500 1800	2, 2.5, 3, 4								2200	10	0.9	0.03	0.06	Distillate from Coal	Pressurized	
		2, 2.5, 3, 4		0.8, 0.95						2200	10	0.8, 0.95	0.03	0.06	↓	↓	
Intermediate Combustor Outlet Temp. Corresponding To Fluidized Bed Temp.										1700	5, 10	0.9	0.03				
										1700	5, 15						
Base Case A	1500	2.5	1000	0.9	0.02	0.02	30	0.02	–	1700	10	0	–	0.09	Bituminous Coal	Fluidized Bed	Wet Cooling Tower
Low Combustor Outlet Temperature Without Recuperator In Pump Up Cycle										1100					3 Coals		
														0.06	High Btu Gas	Pressurize	
															Low Btu Gas		
		2, 2.5, 3, 4													Distillate from Coal		
											5, 15						
																	Dry Cooling Tower
																	Once Through Cooling
														0.09, 0.12			
					0.04, 0.06									0.06			
		4, 5, 7							0.01								
			500, 2000													↓	
Base Case B Atmospheric Furnace With Ljungstrom Recuperator										↓	1	290°F Outlet Temp.			↓	Atmospheric	

Note. All Blanks Spaces Have The Same Value As Base Case A

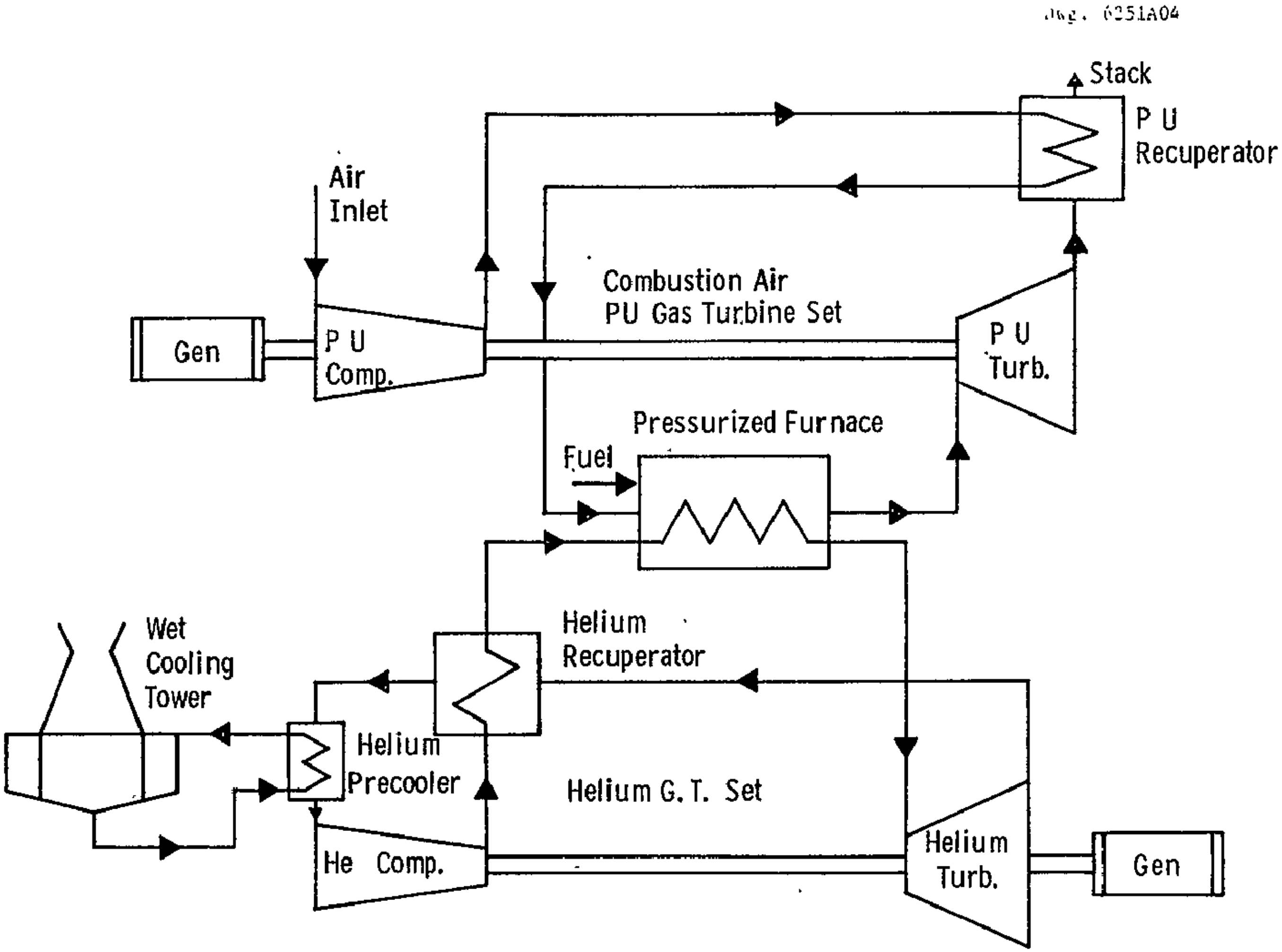

Fig. 7.1—Recuperated pressurized closed-cycle gas turbine systems schematic both helium and pump up cycles recuperated

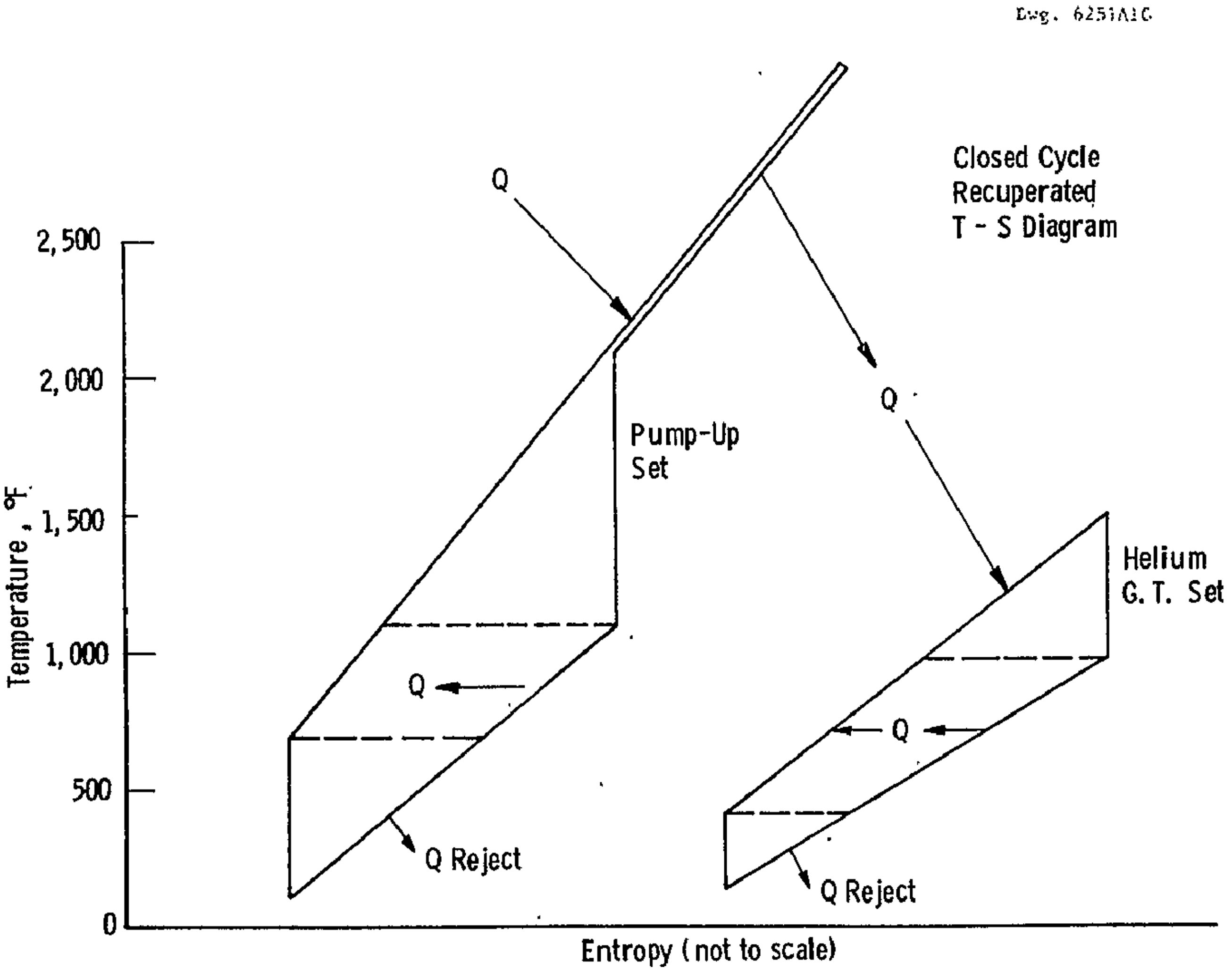

Fig. 7.2—Temperature entropy diagram for a recuperated pressurized closed-cycle gas turbine system

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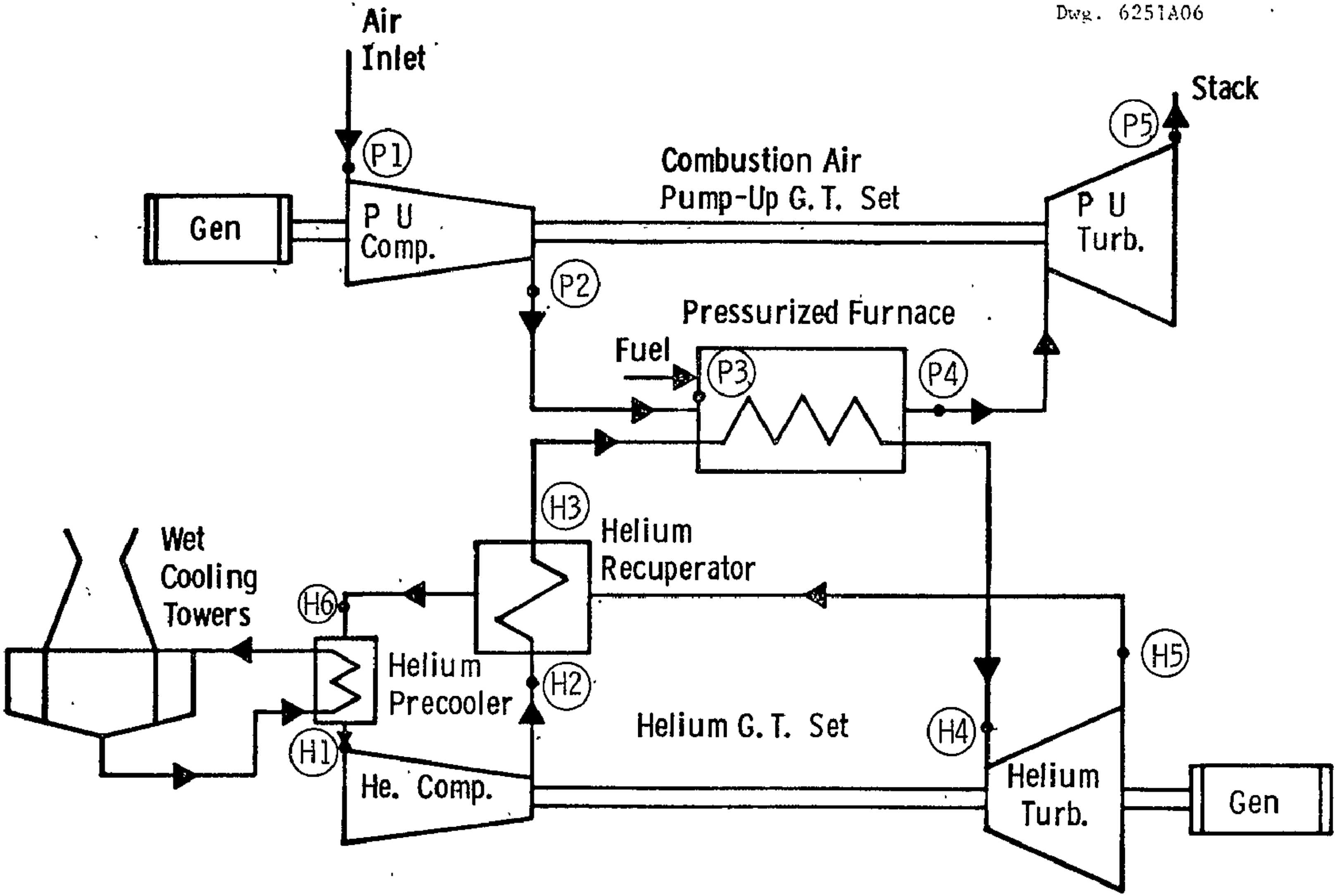


Fig. 7.3—Recuperated-pressurized close-cycle gas turbine system schematic with only the helium cycle recuperated

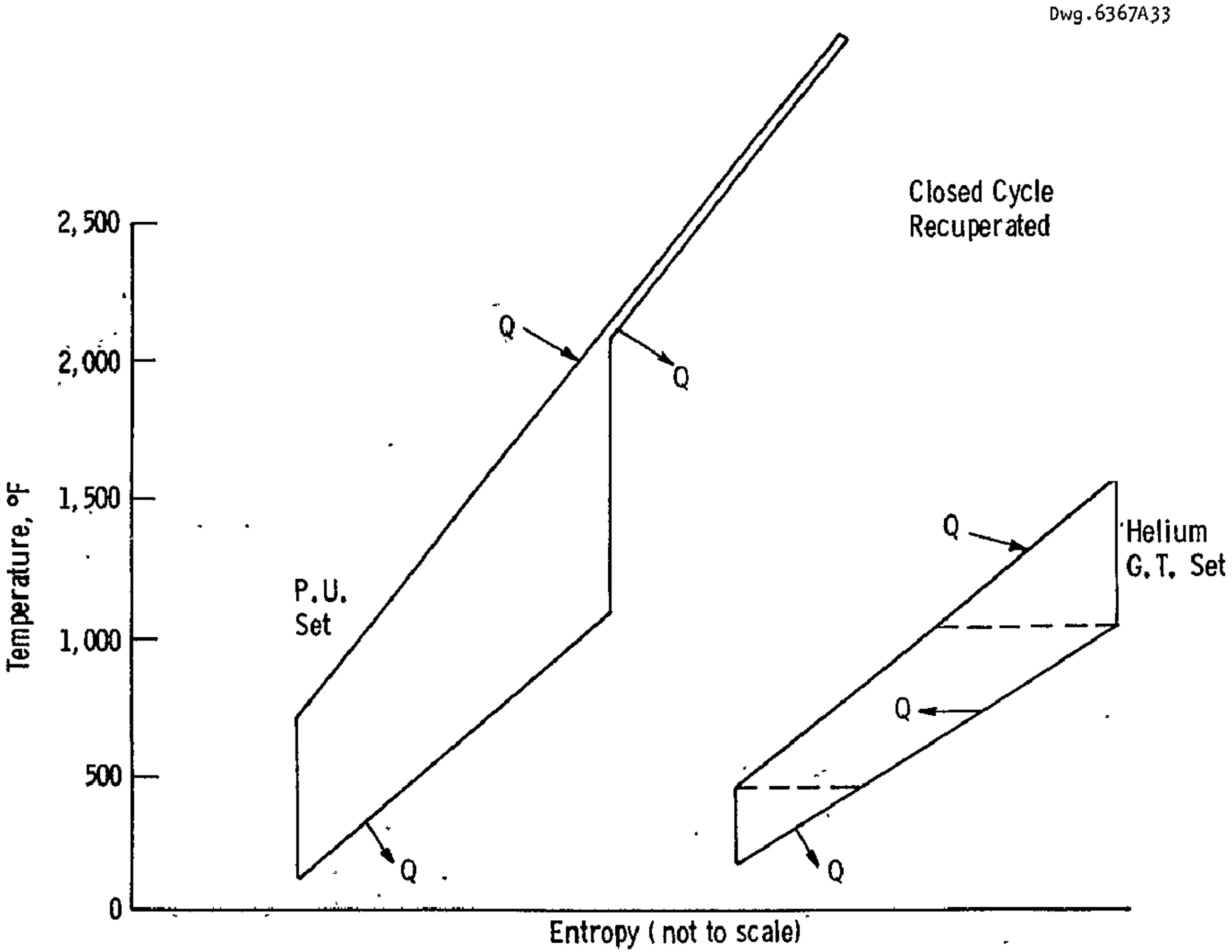


Fig. 7.4—Temperature entropy diagram for a recuperated pressurized closed-cycle gas turbine system

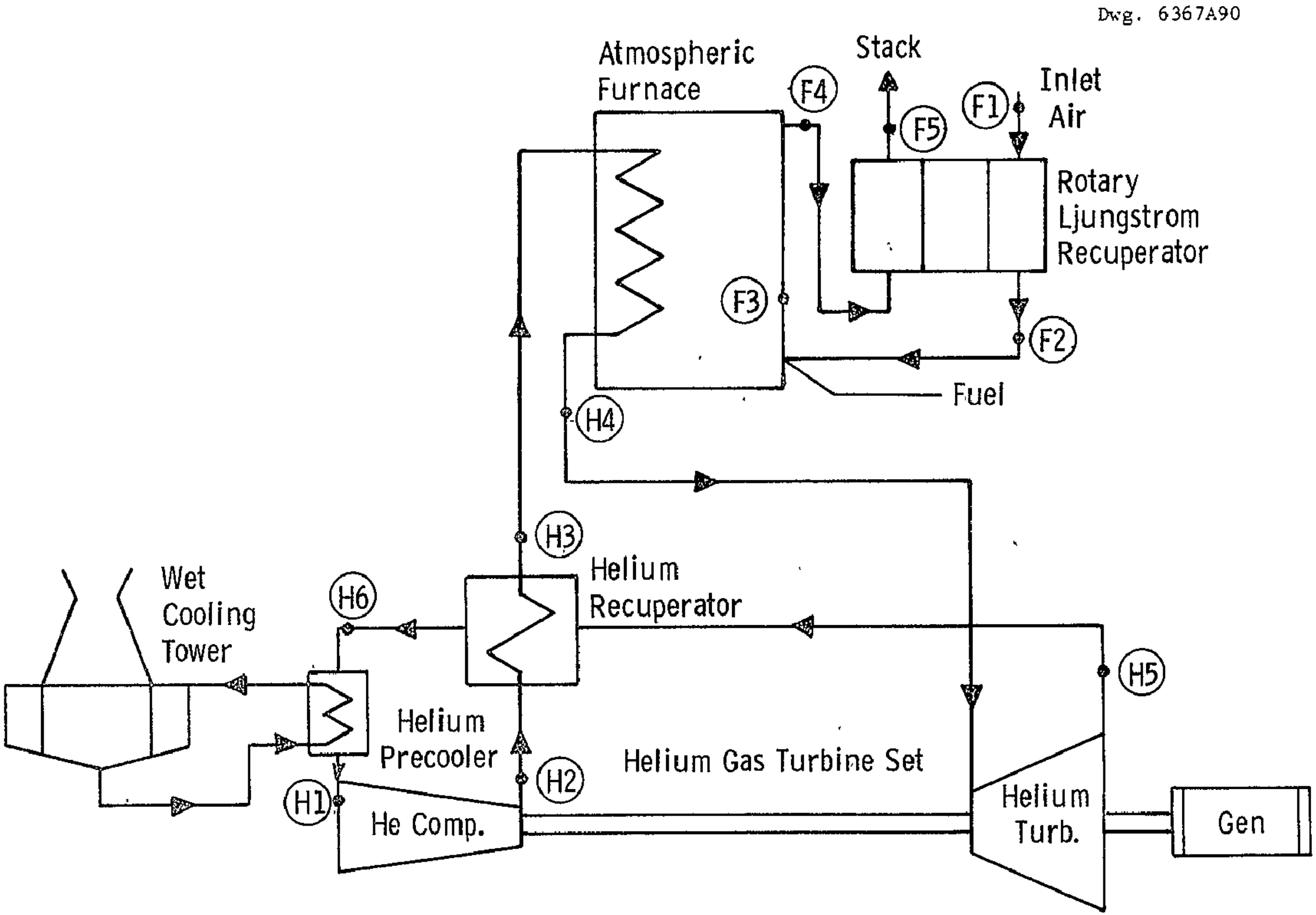


Fig. 7.5—Recuperated atmospheric close-cycle gas turbine system schematic with a Ljungstrom preheater

TABLE 7.2– HELIUM CYCLE-COMBINED

Variations	Helium Cycle									Pump Up Cycle				Bottoming Cycle					Fuel	Furnace Type	Heat Rejection
	Turbine Inlet Temp., °F	Pressure Ratio	Compressor Outlet Pressure	Helium Heater $\frac{\Delta p}{p}$	Vapor Generator			Precooler		Turbine Inlet Temp., °F	Pressure Ratio	Combustor $\frac{\Delta p}{p}$	Vapor Generator $\frac{\Delta p}{p}$	Pressure Psia		Temperature °F		Fluid			
					Outlet Temp °F	Pinch Point ΔT, °F	$\frac{\Delta p}{p}$	Approach ΔT, °F	$\frac{\Delta p}{p}$					Turbine Inlet	Reheater	Turbine Inlet	Reheater				
Helium Turbine Inlet Press. and Temperature	1200	1.5												3500	500	900	950				
	1200	2												2500	350	850	900				
	1200	2.5												2000	250	800	850				
	1500	2												3500	500	950	1000				
Base Case	1500	2.5	1000	0.02	200	40	0.02	–	–	2200	10	0.09	0.04	3500	500	900	950	Steam	Distillate from Coal	Pressurized Furnace	Wet Cooling Tower
	1500	3												2500	350	850	900				
	1800	2.5												3500	350	950	1050				
	1800	3												3500	350	950	1000				
	1800	4												3500	500	900	950				
Pump Up Set Not Combined										1100, 1700 2200											
Bottom Helium Temperature of Precooler					150, 250 300, 350																
					200, 250 300, 350			30	0.01												
No Bottoming Reheat														1600	–	1000	–				
														1250	–	950	–				
Pump Up Set										2200	15			2500	350	850	900				
										1700	5			3500	500	900	950				
										1700	10			2000	250	800	850				
Pinch Point ΔT						60, 80															
Pressure Drop				0.04, 0.06																	
							0.04, 0.06														
												0.06 0.12,									
													0.02, 0.06								
Helium Pressure Level			500, 2000																		
Fuel																			High Btu Gas		
																			Low Btu Gas		
										1700									3 Coals	Fluidized Bed	
Heat Rejection																					Dry Cooling Tower
																					Once Through Cooling
Other Working Fluids With/Without Desuperheating Recuperator														2700	–	700	–	R-12			
See Note 2										1100, 2200				2000	–	550	–	Methylamine			
														2000	–	550	–	Methylamine			Dry Cooling Tower
														2000	–	550	–	Methylamine			Dry Cooling Direct Condensing
With Desuperheating Recuperator														1800	–	900	–	SO_2			

Note 1 All blank spaces have the same values as the base case
Note 2 Helium cycle and 2200°F pump up cycle both have a recuperator effectiveness of 0.9 1100°F pump up cycle is unrecuperated

of the specified range of variation. The pump-up pressure ratio is varied here, and, in addition, the use of a pump-up recuperator is included. The base cases used no pump-up recuperator. Figure 7.3 illustrates the cycle arrangement for this base case, and Figure 7.4 shows the corresponding temperature entropy diagram.

The third group has a low pump-up turbine inlet temperature of 866°K (1100°F) and contains the other parameter variations. A fluidized bed burning coal might require an over-the-bed or outlet heat transfer surface to cool the air to the 866°K (1100°F) level.

The last is a group of one, representing a conventional atmospheric furnace helium heater with rotating Ljungstrom-type regenerator as a base case for comparison. A cycle arrangement is shown in Figure 7.5.

7.2.2 Parametric Point Description of Combined Closed-Cycle Systems

The parametric point selection for the combined closed-cycle gas turbine systems calculations is shown in Table 7.2. The basic cycle arrangement is shown in Figure 7.6, and a typical corresponding temperature entropy diagram is illustrated by Figure 7.7. In general, reject heat from both the pump-up and helium cycles is transferred to the bottom steam cycle. The steam cycles are, for most cases, reheat cycles with both superheater and reheater receiving heat from both gas turbine sets.

The first group in Table 7.2 uses a pump-up turbine inlet temperature of 1478°K (2200°F) with both the pump-up and helium cycles furnishing heat to the bottoming steam cycles. In this group, the parametric variations are in helium top temperature and helium pressure ratio. The base case has been selected from this group with a 1089°K (1500°F) helium turbine inlet temperature and a 2.5-to-1 pressure ratio. Bottoming steam cycle conditions are set at supercritical pressure and at 755°K (900°F) superheater inlet conditions.

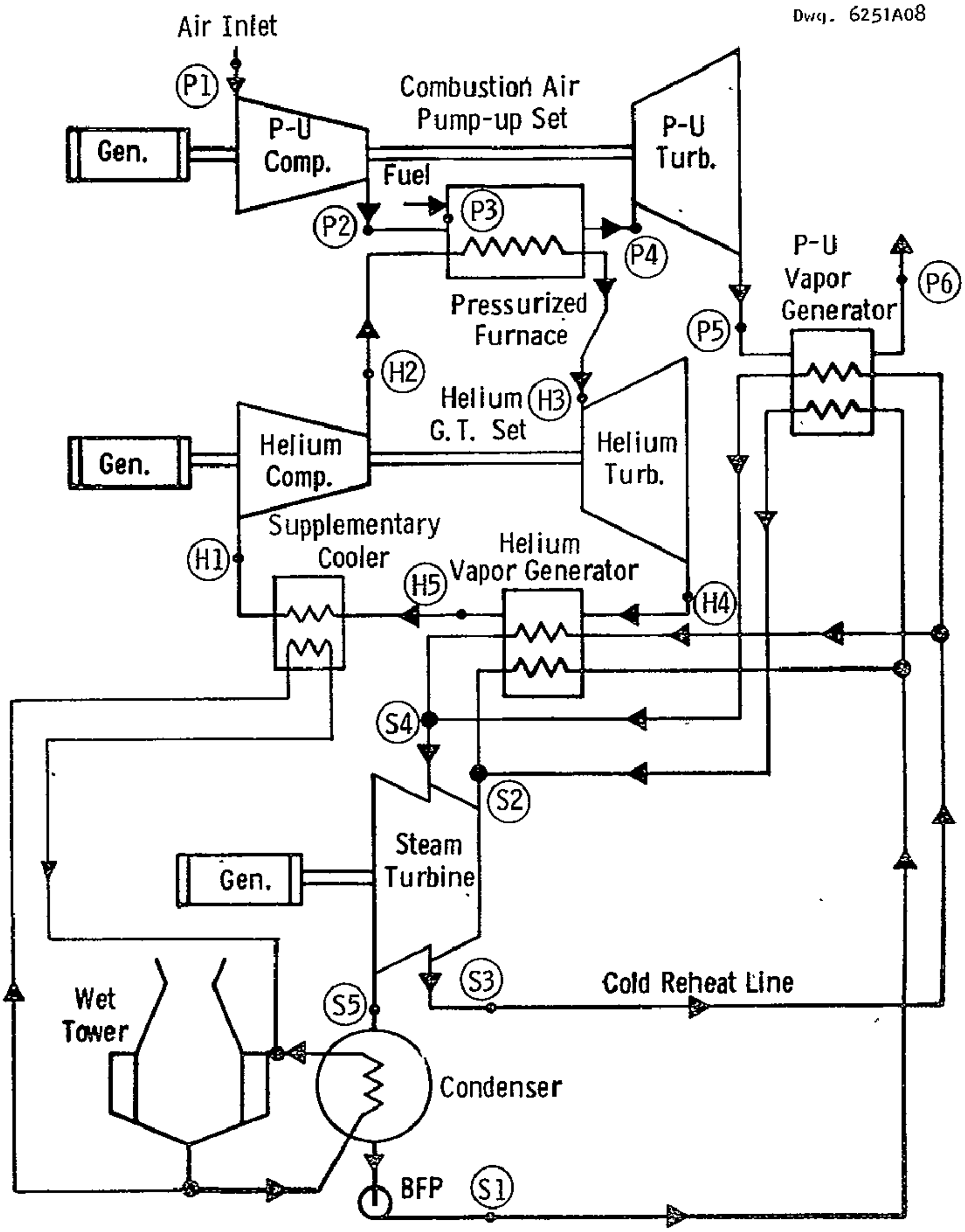


Fig. 7.6—Combined pressurized closed-cycle gas-steam turbine system schematic

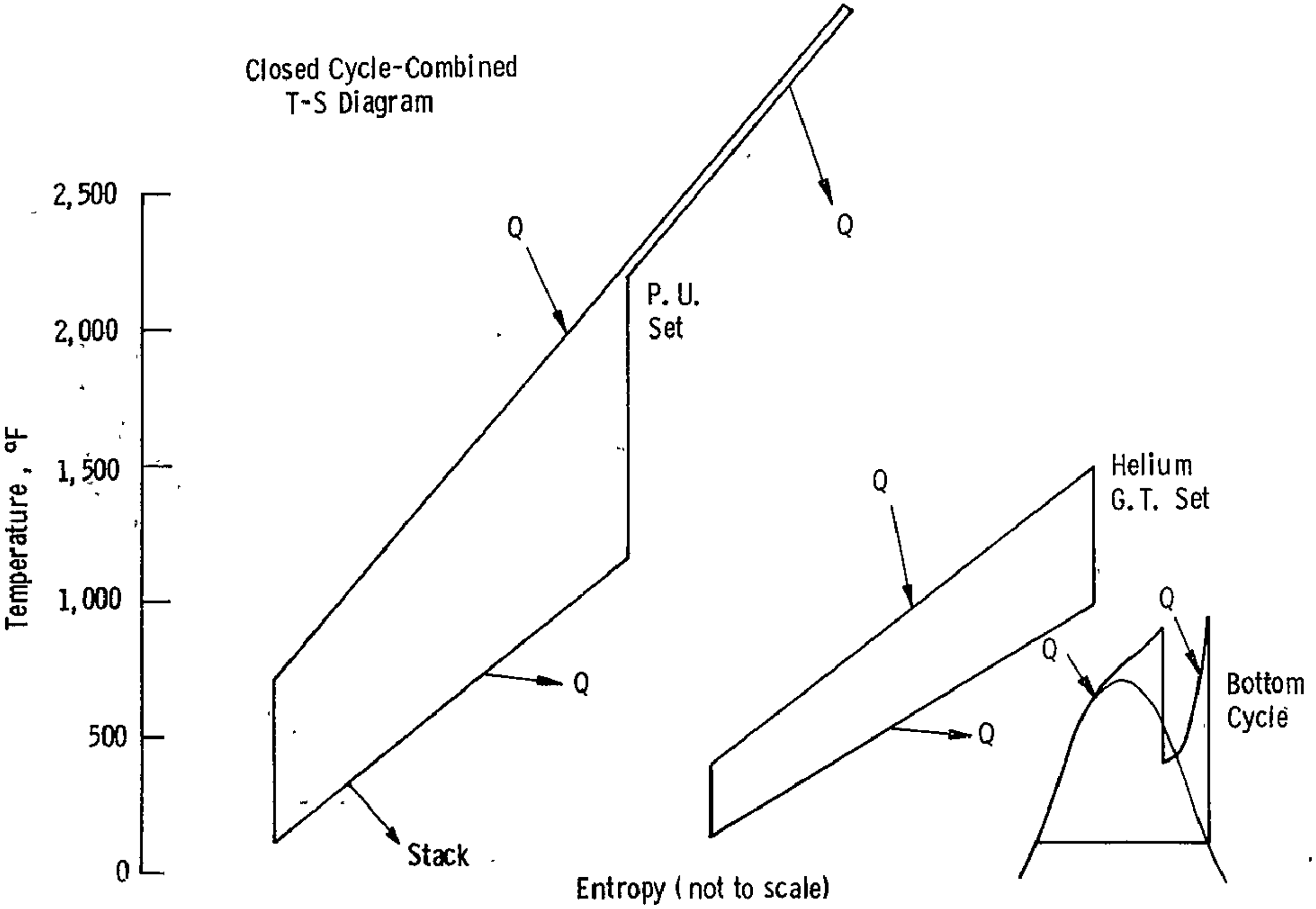
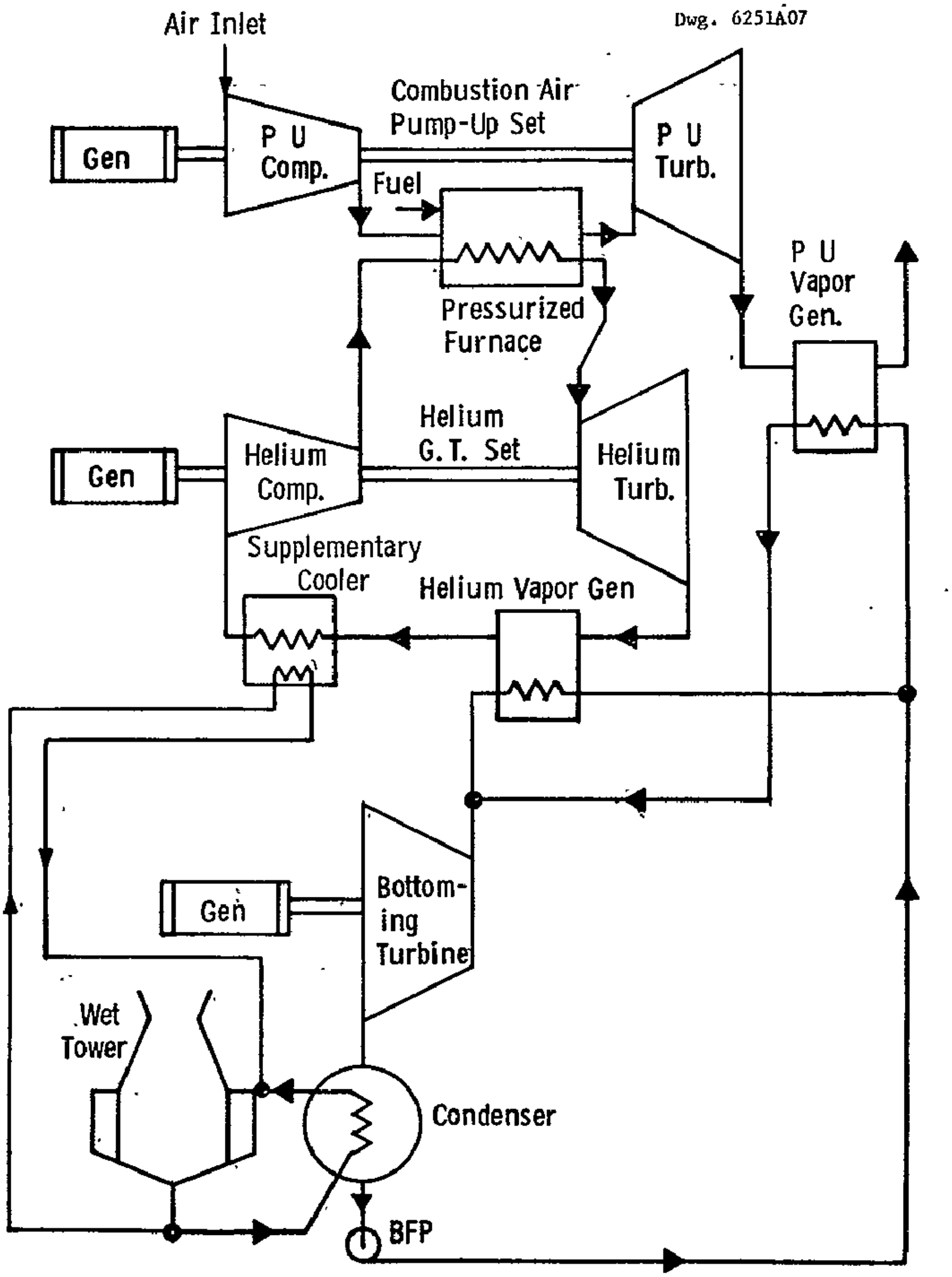


Fig. 7.7—Temperature entropy diagram for a combined pressurized closed-cycle gas-steam turbine system



Closed Cycle - Combined
Flow Diagram

Fig. 7.8—Combined pressurized closed-cycle gas-organic vapor turbine system schematic

The second group has been selected to determine the effect of not transferring heat from the pump-up cycle to the bottom cycle. The helium cycle has a mean top temperature of 1089°K (1500°F), and the pump-up turbine inlet temperatures include 866, 1200, and 1478°K (1100, 1700, and 2200°F).

The third group varies the helium compressor inlet temperature. A helium precooler is used for some cases; also included are two cases without bottom cycle reheat.

The following cases serve to investigate, in turn, the effects of varying pump-up temperature and pressure ratio, pinch point temperature differences, various pressure drops, pressure level, furnace type, and mode of heat rejection.

The last group is for bottom fluids other than steam. All are used in supercritical Rankine cycles without reheat at helium turbine inlet temperatures of 1089°K (1500°F). Fluids used are R-12, methylamine, and sulfur dioxide. (A description of the rationale for selecting these fluids is given at the end of this section.) Figure 7.8 illustrates the general cycle arrangement for these cycles. One R-12 case and one sulfur dioxide case have desuperheating recuperators which are not shown. The methylamine cases represent bottom cycles added to recuperated main cycles; one case has direct condensing in a dry-cooling tower (air condenser).

Vapor generators for combined cycles are utilized under both the pump-up gas turbine and closed-cycle helium turbine in most cases. Approach or pinch point temperature differences were set at values of 22.2, 33.3, and 44.4°K (40, 60, and 80°F). Vapor generator helium outlet temperatures of 339, 366, 394, 422, and 450°K (150, 200, 250, 300, and 350°F) were assumed. Vapor generator gas-side pressure drop ratios of 0.02, 0.04, and 0.06 have been selected.

The basic pump-up turbine parameters of turbine inlet temperature, compressor pressure ratio, and furnace pressure loss were varied.

Table 7.3 - Low Boiling Fluids

Name of Fluid	Molecular Weight	Atmos. Boiling Temp., °F	Critical Constants		Trouton Number	Sat. Pres. at 100°F, psia	Turb. Exh. Area Para. at 100°F
			T, °F	P, psia			
Hydrogen sulfide	34.08	- 79.2	212.7	1307.0	21.1	397.0	1.85
R13B1	148.93	- 72.0	152.6	574.8	19.6	316.0	7.60
Carbonyl sulfide	60.07	- 58.4	221.0	897.0		250.0	2.31
Propylene	42.08	- 52.5	197.2	670.3	19.5	227.6	3.66
Propane	44.09	- 44.0	206.2	617.4	19.4	188.7	4.26
R-22	86.48	- 41.4	204.8	716.0	20.8	212.6	4.99
Ethyl fluoride	48.06	- 35.9	216.0	730.0		180.0	4.11
Ammonia	17.03	- 28.0	271.2	1636.0	23.2	211.7	1.49
Propadiene	40.06	- 25.6	248.0		21.0	182.0	3.17
R-12	120.92	- 18.4	233.6	596.9	19.4	131.6	8.10
G-152A	66.05	- 12.5	236.3	652.0	20.8	126.0	5.69
Methyl chloride	50.49	- 10.7	289.6	968.7	20.7	116.7	4.94
Methyl ether	46.07	- 10.6	260.4	764.4	20.6	123.0	4.70
Propyne	40.06	- 9.9	262.4	776.2	20.9	123.0	4.23
Cyanogen	52.04	- 4.9	262.0	868.0	21.2	116.0	4.90
Sulfur dioxide	64.07	+ 14.0	315.5	1143.0	23.1	84.1	5.75
R-142B	100.50	15.4			20.3	72.0	10.00
Methylamine	31.06	20.3	314.4	1082.0	23.1	78.6	3.96
Isobutane	56.10	21.2	292.5	580.0	19.9	65.6	8.53
1-Butene	56.10	23.0	295.5	583.2	19.5	62.5	8.72
Propyl fluoride	62.09	26.2				60.0	8.55
trans 2-Butene	56.10	33.6	311.0	595.0	19.9	50.0	10.00
R-114	170.93	38.4	294.3	474.8	20.2	46.4	18.30
Methyl bromide	94.95	38.5	375.8	1227.0	20.6	50.0	12.00
cis 2-Butene	56.10	38.7	320.0	610.0	20.2	46.0	10.40
G-133A	128.49	43.0	306.5	589.6	21.2	45.0	20.00
Dimethylamine	45.08	45.4	328.1	770.0	22.6	45.4	7.78
Methanethiol	48.10	45.7	386.2	1049.6	21.0	49.7	7.93
1-Butyne	54.09	47.5				40.0	10.50
R-21	102.93	48.0	353.3	749.7	21.1	40.0	14.20
Ethylene fluoride	66.05	50.0				38.0	12.00
Ethylene oxide	44.05	51.4	383.0	1044.0	21.5	38.6	9.20
Ethyl chloride	64.52	54.0	369.0	764.0	21.3	34.8	12.90
Cyclobutane	56.10	55.4	385.0	740.0		34.0	12.10
Ethylamine	45.08	61.9	361.8	816.4	22.3	32.7	9.78
Acetaldehyde	44.05	69.8	370.0		20.4	31.0	11.40
R-11	137.38	75.3	388.4	635.0	20.1	23.6	26.00
Dibromodifluoromethane	209.84	76.1	388.8	600.0		23.0	31.20
Water	18.02	212.0	705.4	3206.2	26.0	0.949	98.30
2-Butyne	54.09	80.8				21.0	16.90

Turbine inlet temperatures of 866, 1200, and 1478°K (1100, 1700, and 2200°F) were selected. The first corresponds to relatively large energy transfer directly to the closed-cycle fluid in the pressurized furnace; the second value was selected on the basis of its compatibility with the operating temperature levels of proposed fluidized bed processes; and the third value corresponds to base case open-cycle gas turbine values. Compressor pressure ratios of 5, 10, and 15 to 1 were selected, all compatible with single-shaft gas turbine technology. Furnace pressure drop ratios[†] of 0.02, 0.04, 0.06, 0.09 and 0.12 were used.

Heat rejection methods include once-through, wet tower, and dry tower systems. One system, a methylamine bottomed cycle, used direct dry tower condensing.

Both pressurized furnaces burning liquid fuel and pressurized fluidized bed furnaces firing coal were included in the study. An atmospheric pressure conventional power generation furnace was used for one case.

7.2.3 Selection of Bottoming Cycle Organic Fluids[*]

When the bottom fluid itself may be varied the number of possible parameter combinations increases greatly. Since the number of cases is limited, they were chosen to illustrate particular aspects.

The fluids themselves were selected from a list of low-boiling fluids shown on Table 7.3. In this table the turbine exhaust area parameter (TEAP) illustrates the relative turbine exhaust area for each of the fluids when used for bottoming cycles under comparable conditions.

To derive the TEAP, it is assumed that for each fluid:

- Heat is rejected at the same specificed temperature.
- The latent heat represents all of the rejected cycle heat.

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[*] References 7.3 through 7.12 were used in determining organic bottoming fluid properties.

[†] helium pressure drop ratios of 0.02, 0.04, 0.06 and combustion gas pressure drop ratios of 0.06, 0.09 and 0.12.

- The cycle input heat is the same.
- The leaving velocity energy is the same.
- The specific volume is given by the perfect gas equations.

$$\text{Exhaust Area, } A = \frac{\text{(Flow Rate)(Specific Volume)}}{\text{(Axial Velocity)}} = \frac{\dot{W}\ V}{V} \qquad (7.1)$$

$$A = \frac{\left(\dot{W}\ L\right)\left(\sqrt{\dot{W}\ L}\right)\left(R\right)}{\left(\sqrt{\dot{W}\ V^2}\right)\left(R\ T/M\ P\ v\right)} \sim \frac{T}{M\ P\ L^{1.5}}$$

where $\dot{W}$ is the mass flow rate, L is the latent heat, R the universal gas constant, and M the molecular weight. Since each quantity within parentheses is a constant in the preceding expression,

$$A \sim T/M\ P\ L^{1.5}$$

TEAP is defined as this ratio times 10^5.

$$\text{TEAP} = T \times 10^5/M\ P\ L^{1.5} \qquad (7.2)$$

This equation is convenient to use if tabulations of latent heats and saturation pressures are available, but frequently they are not. The latent heat may be approximated using Trouton's law and then adjusting it from the boiling point to the specified temperature.

Trouton's law simply states that the molal atmospheric latent heat of any substance is approximately 21 times the boiling temperature. This rule holds well for a large number of substances, but there are also marked deviations. When the latent heats are known, we can find Trouton's number as the number to substitute for 21 in order to give the correct latent heat. In general, associated fluids such as water and the alcohols tend to have high Trouton numbers; the number for water being 26.

For our present use it will be convenient to normalize the Trouton numbers about 21 by using a correction factor, q, defined as:

$$q = \text{Trouton No}/21$$

so that

$$L_B = \frac{21\ q\ T_B}{M} \tag{7.3}$$

at the boiling point.

Since all of the fluids are to be compared at the same sink temperature, it is necessary to correct the latent heat from the various boiling points to the common sink temperature. Watson (Reference 7.11, p. 233) relates latent heat at two different temperatures as:

$$\frac{L}{L_1} = \left(\frac{1 - T_R}{1 - T_{R1}}\right)^{0.38} \tag{7.4}$$

in which T_R is the reduced temperature.

$$\frac{L}{L_B} = \left(\frac{1 - \frac{T}{T_c}}{1 - \frac{T_B}{T_c}}\right)^{0.38} = F\left(\frac{T_B}{T}, \frac{T_B}{T_c}\right) = \left[\left(\frac{1 - \frac{T_B/T_c}{T_B/T}}{1 - T_B/T_c}\right)^{0.38}\right] \tag{7.5}$$

in which the bracketed quantity is F. Then,

$$L = L_B\ F = \frac{21\ q\ T_B\ F}{M} = \left(\frac{21\ q\ T}{M}\right)\left(\frac{T_B}{T}\right)\left(F\right) \tag{7.6}$$

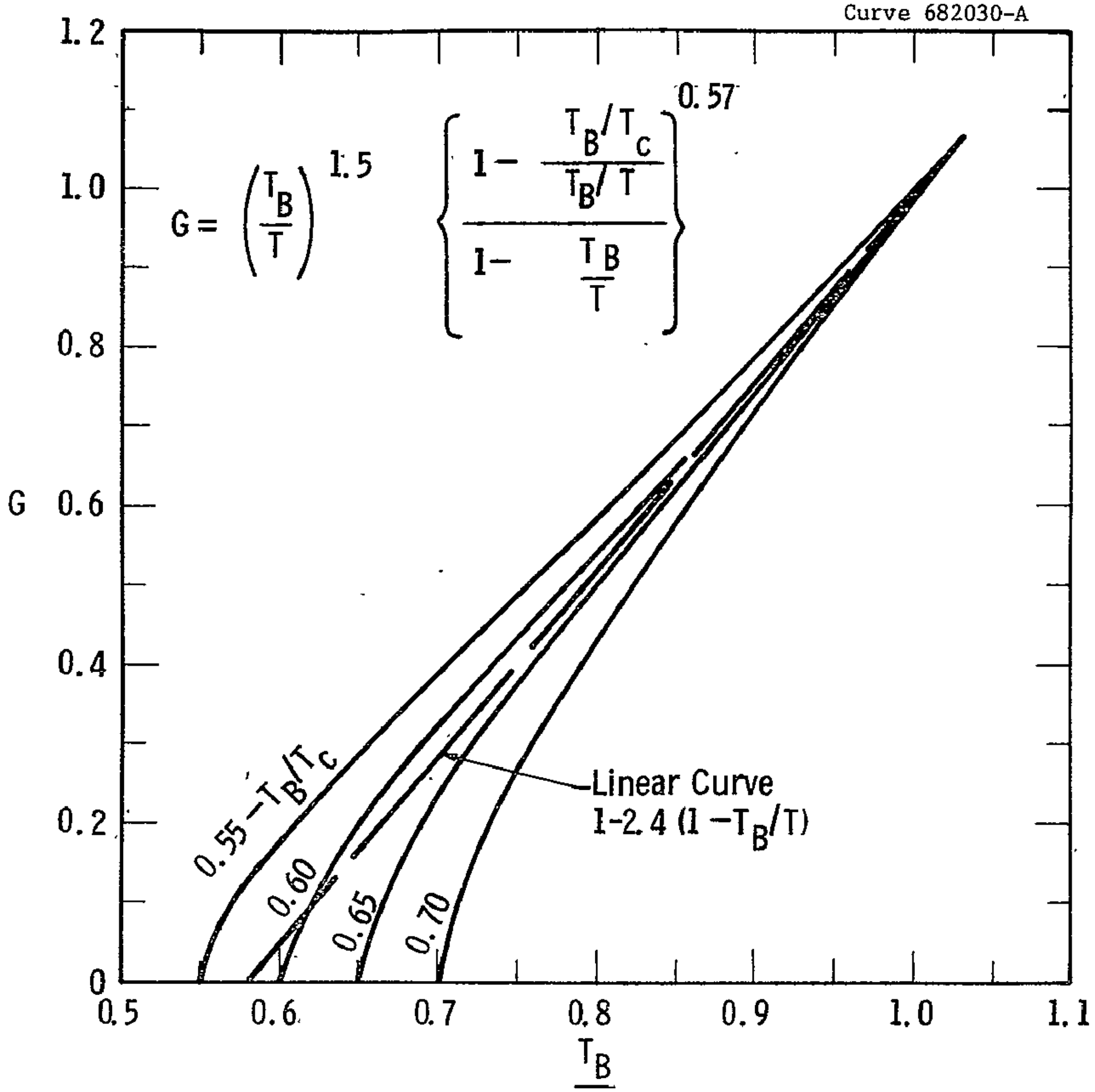


Fig. 7.9 — "G" function vs $\frac{T_B}{T}$

Substituting in the definition for TEAP:

$$\text{TEAP} = \frac{T \times 10^5}{M\,P\left[\left(\frac{21\ q\ T}{M}\right)\left(\frac{T_B}{T}\right)\left(F\right)\right]^{1.5}}$$

$$= \left(\frac{10^5}{21^{1.5}}\right)\left(\frac{1}{\sqrt{T}}\right)\left(\frac{\sqrt{M}}{P}\right)\left(\frac{1}{G\ q^{1.5}}\right)$$

$$= \left(\frac{1040}{\sqrt{T}}\right)\left(\frac{\sqrt{M}}{P}\right)\left(\frac{1}{G\ q^{1.5}}\right) \qquad (7.7)$$

in which

$$G = G\left(\frac{T_B}{T}, \frac{T_B}{T_c}\right) = \left[\left(\frac{T_B}{T}\right)\ F\right]^{1.5}$$

$$= \left(\frac{T_B}{T}\right)^{1.5}\left\{\frac{1 - \frac{T_B/T_c}{T_B/T}}{1 - \frac{T_B}{T}}\right\}^{0.57} \qquad (7.8)$$

G is plotted in Figure 7.9.

This latter form of TEAP displays the theoretical effects with greater clarity. It is dominated by the inverse saturation pressure function; the molecular weight increases area directly in a square root relation; fluids with high Trouton number reduce area in a strong 1.5 power relation, but the range of values is small; the compressibility

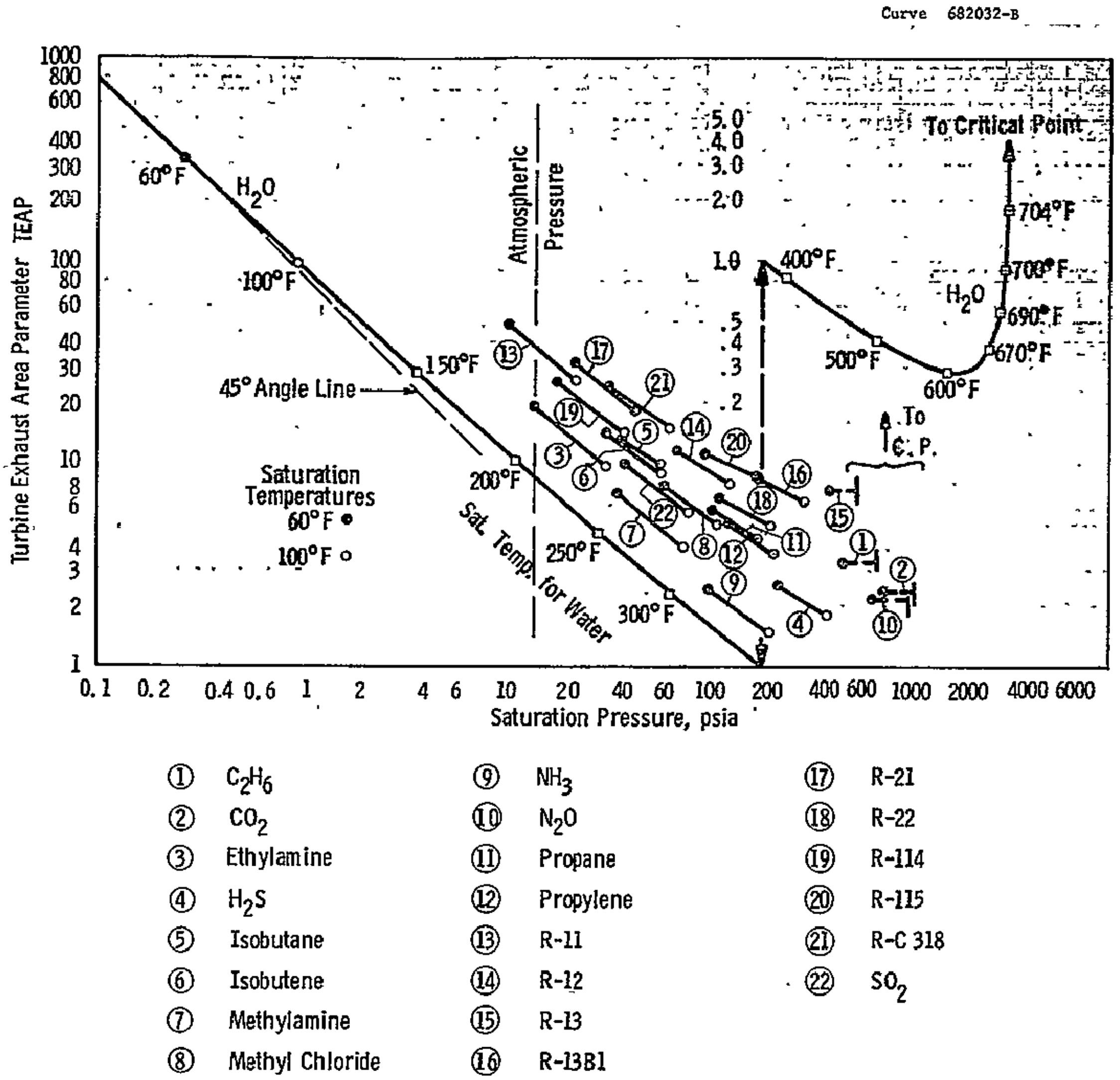


Fig. 7.10—Turbine exhaust area parameter vs saturation pressure for low-boiling fluids

factor, Z, which was ignored in the derivation, would also act as a systematic variable causing a slight reduction at high pressures.

TEAP values for steam and some other fluids are plotted vs saturation pressure in Figure 7.10. The values for steam are plotted up to high pressure to show the form of the function even though this is outside of the intended range of application. The values for the other fluids are plotted for two different temperatures and demonstrate that the relation between fluids is generally the same and largely independent of the temperature at which compared.

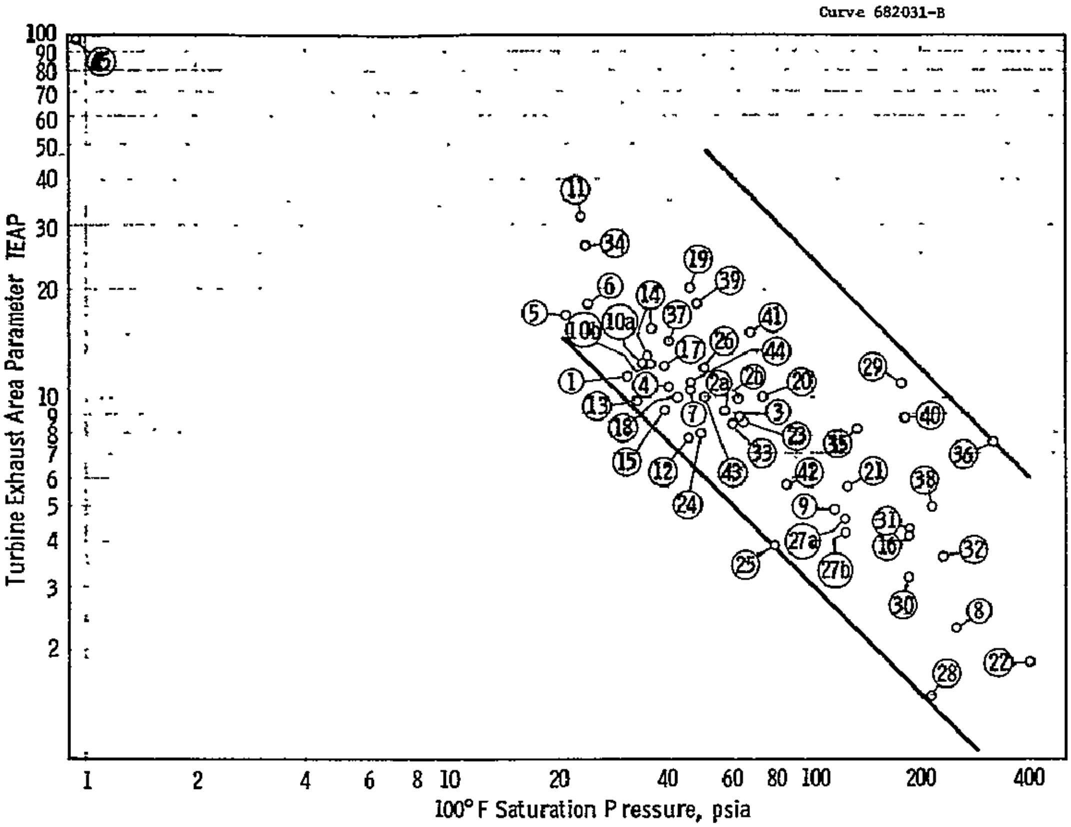
Figure 7.11 shows the TEAP values for fluids in Table 7.3, all at 311°K (100°F). The bottoming fluids for the study were chosen in the intermediate TEAP/pressure range so the turbine exhaust area would be greatly reduced over that of steam yet not have so high a saturation pressure as to make them difficult to contain. Fluids R-12, methylamine, and sulfur dioxide were selected.

R-12 (Dichlorodifluoromethane) was selected as a well-known, nontoxic, nonflammable fluid. It is used in cycles which illustrate the effects of poor thermodynamic fit due to stability limitation and also to low-temperature superheated turbine exhaust.

Methylamine was selected as having the best area-pressure characteristics in the intermediate range (see Figure 7.11). It is highly flammable. It was used in recuperated cycles for which stability temperature limits are not critical. These cycles were also used to illustrate the direct deployment of the condensing vapor to air condenser made possible with the low volumetric exhaust flow.

Sulfur dioxide was selected, also from the intermediate area-pressure characteristic range, for its high-temperature stability. It is rather toxic. It was used in a cycle illustrating good thermodynamic fit made possible when not precluded by stability temperature limitations.

These fluid selections and their assignment to illustrate particular cycle effects are rather arbitrary. Note that the cycle effects



①	Acetaldehyde	⑯	Ethyl Fluoride	㉛	Propane
②	(a) Butane (b) Isobutane	⑰	Ethylene Fluoride	㉜	Propylene
③	1-Butene	⑱	Ethylmethyl Ether	㉝	Propyl-Fluoride
④	1-Butyne	⑲	G-133A	㉞	R-11
⑤	2-Butyne	⑳	G-142B	㉟	R-12
⑥	2-Chloropropene	㉑	G-152A	㊱	R-13B1
⑦	cis-2-Butene	㉒	H_2S	㊲	R-21
⑧	COS	㉓	Isobutene	㊳	R-22
⑨	Cyanogen; Methyl Chloride	㉔	Methanetial	㊴	R-114
⑩	(a) Cyclobutane (b) Cyanogen Chloride	㉕	Methylamine	㊵	R-115
⑪	Dibromodifluoromethane	㉖	Methyl Bromide	㊶	R-C318
⑫	Dimethylamine	㉗	(a) Methylether (b) Propyne	㊷	SO_2
⑬	Ethylamine	㉘	NH_3	㊸	trans-2-Butene
⑭	Ethyl Chloride	㉙	Octafluro-propane	㊹	Trimethylamine
⑮	Ethylene Oxide	㉚	Propadiene	㊺	Water

Fig. 7.11 —Turbine exhaust area parameter vs saturation pressure at 100°F for low-boiling fluids

illustrated are not an intrinsic characteristic of the particular fluid but would apply for any candidate fluid that would fit a particular application.

7.3 Approach

7.3.1 Overall Cycle Calculation Procedure

The number of distinctly different combinations of pump-up, helium, and bottoming cycle configurations for this conversion system is large compared with other systems. Many of the parametric values for the helium cycle, however, are common for several of these combinations. Individual cycle calculations, therefore, were made for the pump-up loop cycles, helium cycles, and bottoming cycles. Subsequently, each parametric point cycle combination was assembled from the individual component calculations to give the resultant efficiency and power.

An example for a typical closed regenerative cycle is described as follows. Figure 7.12 illustrates the two subsystems: pressurized combustor or pump-up cycle and helium loop subsystem. For all cases the pump-up airflow is kept constant at 408 kg/s (900 lb/s). Power output and heat output, $\dot{Q}_1$, are computed as a function of turbine inlet temperature, compressor pressure ratio, air equivalence ratio, fuel type, and recuperator effectiveness. Likewise, helium cycle power output and heat input, $\dot{Q}_{he}$, is computed as a function of turbine inlet temperature, compressor pressure ratio, recuperator effectiveness, pressure losses, intercooler and precooler approach values, and heat rejection system for a unit mass flow. The assembly consists then of first determining helium flow for each parametric point from:

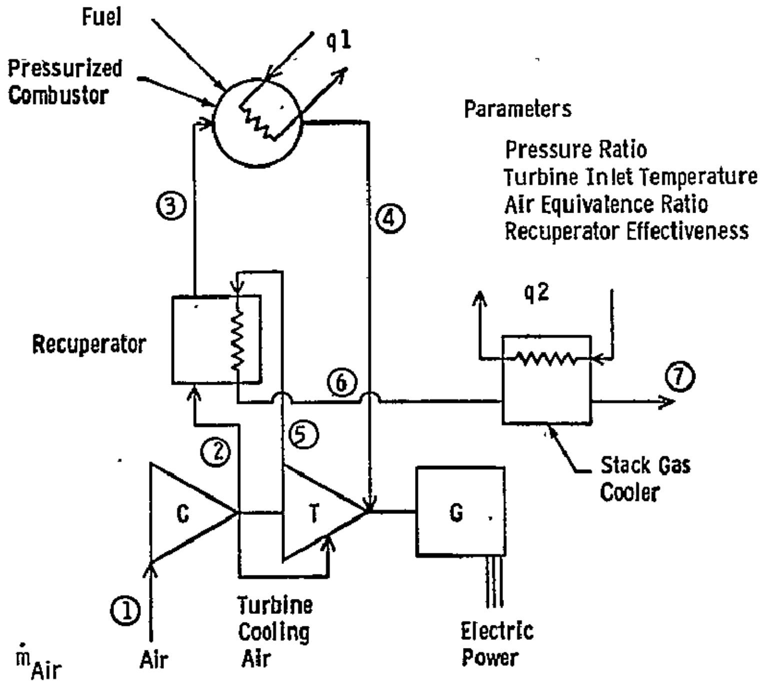
$$\dot{W}_{he}\ \Delta h_{H}e = \dot{W}_{pu}\ \Delta h_{pu}$$

where $\dot{W}_{He}$ = helium flow rate

$\dot{W}_{pu}$ = pump-up turbine compressor inlet airflow [408 kg/s (900 lb/s)]

Dwg. 1675843

Pressurized combustor sub-system



HELIUM LOOP SUBSYSTEM

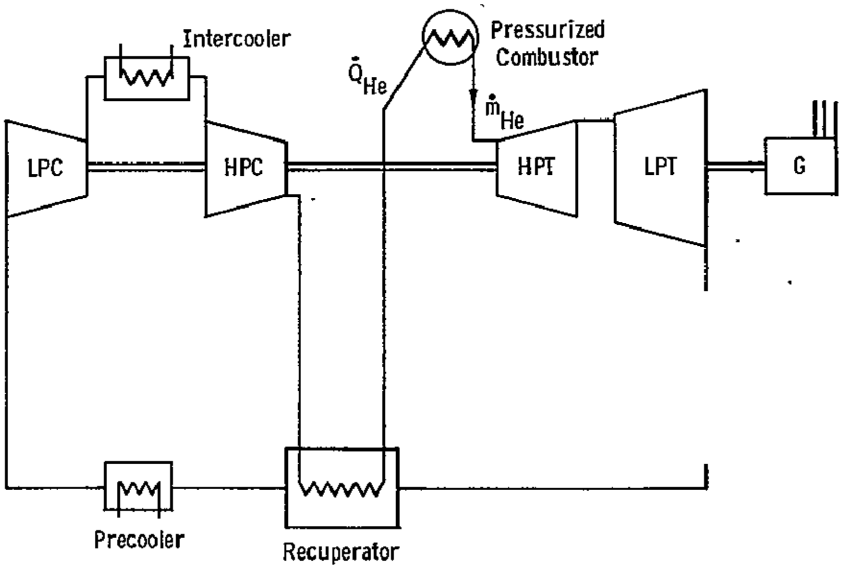


Fig. 7. 12—Recuperated-pressurized closed-cycle gas turbine system

Δh_{pu} = enthalpy drop based on the difference between furnace combustion section outlet temperature (typically near stoichiometric) and pump-up turbine inlet temperature

Δh_{He} = enthalpy rise based on the difference in temperature between helium compressor discharge and turbine inlet.

Subsequently, helium power output is determined and added to the pump-up cycle power to yield the gross power output. After subtracting station auxiliary power requirements, net power output is divided into the higher heating value heat input to the pump-up cycle to determine net heat rate.

A similar procedure is used in computing combined closed-cycle performance.

7.3.2 Organic Bottoming Cycle Calculation Procedure

The organic cycles were assembled in a manner similar to that of the other combined cycles. Since there were only a few cycles, each cycle was fitted closely to the available heat line from the pump-up and helium cycles, changing the parametric values from those initially chosen in order to better demonstrate the intended effect.

For R-12 (Points C46 and C47),* thermodynamic properties were obtained from the tables in Reference 7.6 except that in that pamphlet the higher temperature properties existed only on a small-scale figure. For both cycles the bottom pressure was taken as 0.931 MPa (135 psi) abs, corresponding to 312°K (101.7°F). The turbine inlet temperature and pressure were set at 644°K (700°F) and 1.724 MPa (2500 psi) abs,

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*As results from both recuperated closed-cycle systems and combined closed-cycle systems are frequently referred to, the cycle point numbers as described in detail in Subsection 7.4, are preceded by an "R" or a "C", respectively, for clarity and convenience.

respectively. The turbine expansion was calculated in two parts, from 17.24 to 3.447 MPa (2500 to 500 psi) abs and from 3.447 MPa (500 psi) abs to the turbine exhaust pressure. For Point C46, which contained an R-12 desuperheating recuperator, a 17.2 kPa (2.5 psi) drop was assumed. The turbine efficiency was assumed to be 0.86 for the high-pressure portion and 0.89 for the low-pressure portion. The pump work was calculated from the inlet liquid volume and pressure rise at an efficiency of 0.75. A 15% pressure drop ratio was assumed for heating to turbine inlet temperature. (A temperature-entropy diagram for these cycles is given in Subsection 7.4 as Figures 7.44 and 7.45.) The pinch point temperature difference was taken as 22.2°K (40°F), and the R-12 flow for Point C46 was calculated as that required to receive all of the available heat from both the pump-up and helium cycles to heat the R-12 to the turbine inlet temperature.

The Rankine feedheat* was obtained by cooling the helium to a specified temperature [366°K (200°F)] and by cooling the superheated R-12 exhaust down to 353°K (176°F). No additional heat could be absorbed, and the pump-up exhaust was discharged to stack at the pinch point temperature. For Point C47, the R-12 flow was calculated from the total heat available from both the pump-up and helium cycles. The R-12 net power was calculated using an electrical and mechanical efficiency of 0.965 and by subtracting the pump power. The methylamine cycles are slightly different in that the helium and some of the pump-up cycles which they bottom were recuperated. The assembly calculation process was similar.

Since there were no conveniently available thermodynamic tables for methylamine, some of the properties were calculated for specific points. (A skeleton temperature-entropy diagram for these cycles is depicted on Figure 7.47 of Subsection 7.4). For temperatures below 323°K (122°F) there were tabulated values in Reference 7.4. The zero pressure specific heat enthalpy and entropy were taken from Reference 7.11, p. 759. The enthalpy and entropy adjustments for pressure were calculated using Pitzer's acentric method which is described in Reference 7.13, Appendix I.

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* Fig. 7.44

From Figure 7.47 (given in Subsection 7.4) it can be seen that the methylamine turbine expansion ends close to the saturation line, and the relatively straight heating line is conducive to an excellent fit to the heat available line. The condenser temperatures were adjusted slightly in order to correspond to tabulated values. For wet tower application (Points C48 and C49), the temperature was set at 313°K (104°F): for dry tower application, C50, the temperature was set at 323°K (122°F). The difference of 10°K (18°F) is the same as for other cycles, and the comparison should correspond. Since there is no advantage in raising the compressor inlet temperature for a recuperated cycle, the helium cycle bottom temperature was made 20°K (36°F) above the condenser temperature; i.e., 333°K (140°F) for the 313°K (104°F) condensing temperature and 343°K (158°F) for the 323°K (122°F) condensing temperature.

The heater pressure drop ratio for these fluids was assumed to be 10%, and the turbine inlet pressure was taken as 17.24 MPa (2500 psi) abs for Points C48, C50, and C51. Since the bottoming cycle in C49 was placed below a recuperated helium cycle but with an 866°K (1100°F) unrecuperated pump-up cycle, there was insufficient heat temperature to raise the methylamine to 533°K (500°F) as was done in the other cycles. A vapor turbine inlet temperature of 505°K (450°F) was selected. At that temperature, a pressure of 1.379 MPa (2000 psi) abs gave a better fit. The turbine efficiencies were assumed to be 0.88.

7.3.3 Cycle Fit and Heat Exchange Effectiveness Considerations

When assembling the results for the combined cycle from the various subcycles (pump-up, helium, and steam), the low-temperature heat demand (feed heating) of the steam cycle was not sufficient to fully cool the helium to the 366°K (200°F) chosen as the compressor inlet temperature. For the base case, the helium could be cooled only to 398°K (250°F) in the vapor generator. The additional heat will be rejected to sink in order to cool the helium 31°K (56°F) further. This will not have a large effect on the plant. The energy involved does not have much availability. The temperature approach to the cooling water is large, and the required

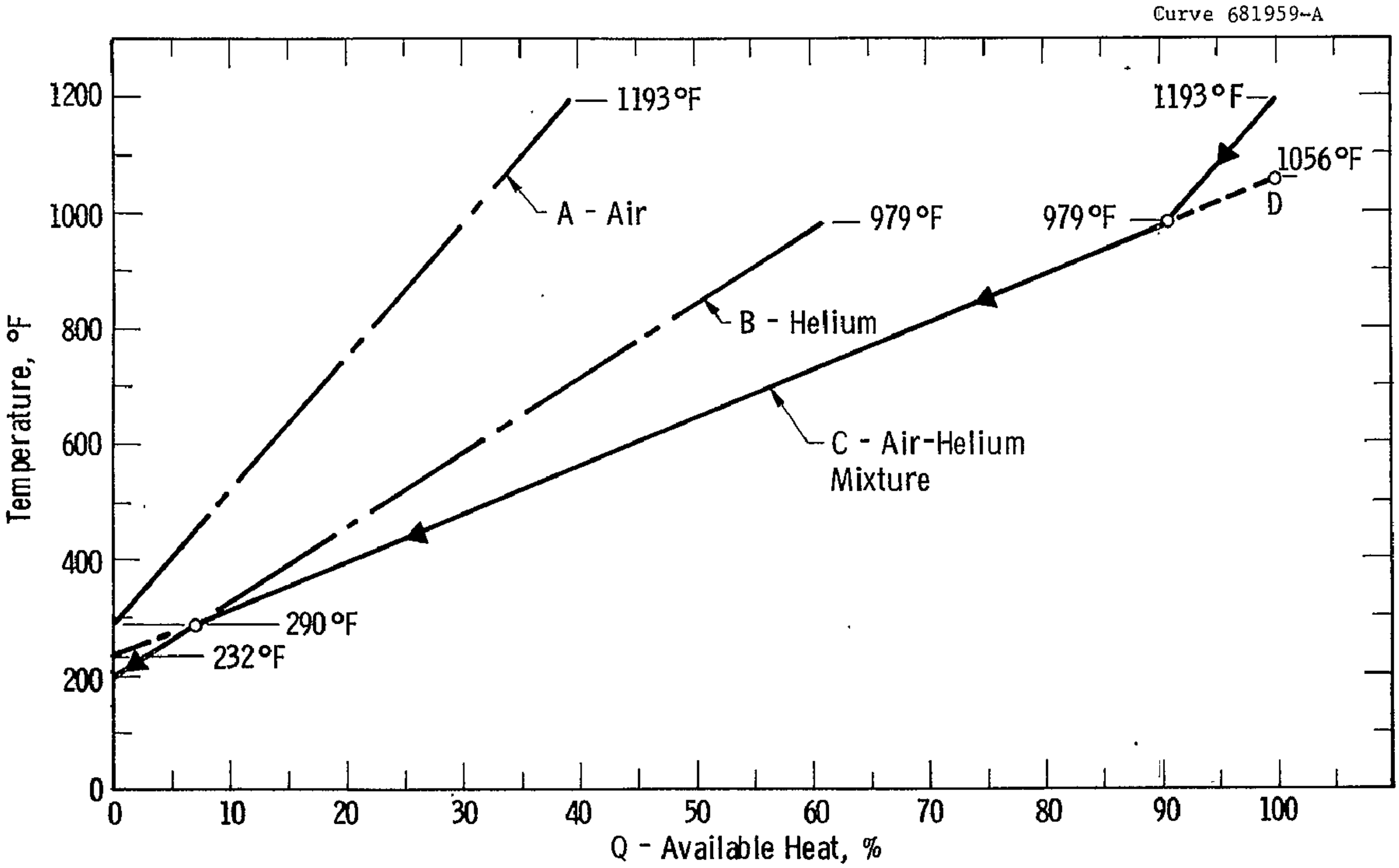


Fig. 7.13—Available heat (air and helium) for feed water heating (base case, Point C5)

heat exchange surface will be relatively small. Functionally, there will be a precooler, although none was originally intended.

It became apparent that most of the steam-bottomed combined cycles would require a similar adjustment; the other fluid cycles would not.

Figure 7.13 depicts the heat load requirements of the steam cycle for Point C5 (base). Lines A and B represent the heat available from the air and helium cycles, respectively. At the time of fitting these lines to the steam cycle, the flow rates of both the air and helium have been determined and the absolute values for Lines A and B were known. The steam flow, however, had not then been determined. Lines A and B were both assumed to be linear, and their enthalpy rates were added to form Line C. For this case, the right-hand steep end represents the air turbine exhaust cooling from the 918°K (1193°F) to the helium exhaust temperature 799°K (979°F). The left-hand steep segment represents the helium cooling from the 416°K (290°F) air lower limit to 366°K (200°F).

Since the air and helium flows are known, it is convenient to extend the combined part of line C to a fictitious end point, D. This represents the inlet temperature if both the air and helium started at the same temperature and both transmitted the same sensible heat as the air alone does in this region. Obviously, this fictitious temperature cannot be used for heat transfer calculations.

Point D can be considered as the end point on the steam heat requirement curve and the Line C rotated to fulfill the pinch point requirement. This is depicted on Figure 7.14 with the pinch point, E, corresponding to 628°K (670°F) on the steam cycle. The flow rate for steam is now calculated so that the heat required to the right of this point exactly matches that available from the air and helium cycles down to Point E. The additional heat required by the steam below the pinch point then can be calculated. It was intended that this heat be supplied by cooling the helium to 366°K (200°F) and by cooling the air as much as required but not below 416°K (290°F). Thus, the air would be discharged at

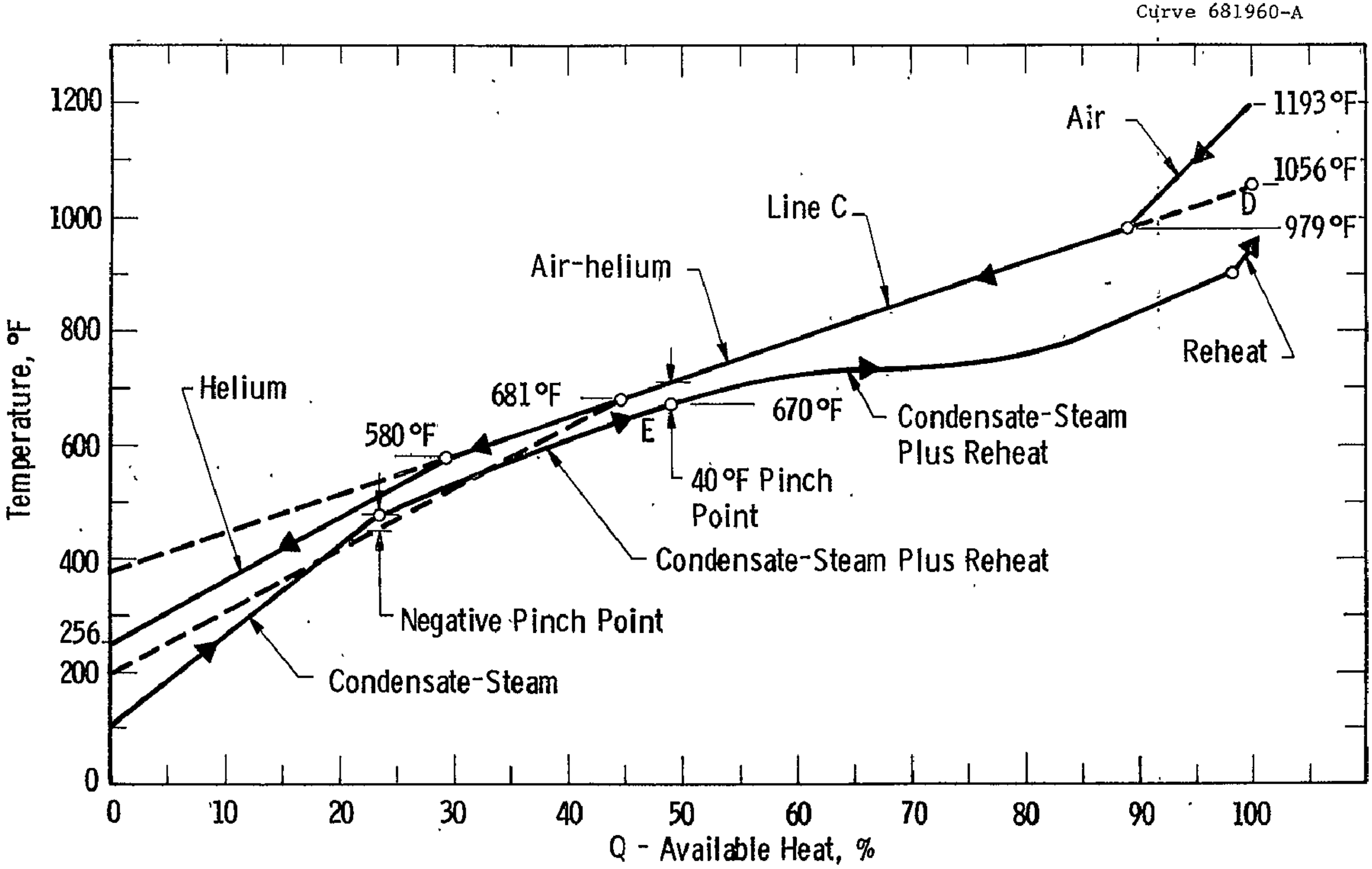


Fig. 7.14—Feed heater match showing effect of pinch point on air and helium leaving temperature (base case, Point C5)

634°K (681°F), producing the situation shown dotted in Figure 7.14. The left helium-cooling line shows a negative pinch point at the reheat knee, which is obviously impossible.

There is still sufficient heat in the discharge air to avoid this condition; but when this is used, the helium can no longer be completely cooled by the steam cycle. This cooling scheme is depicted by the solid lines in Figure 7.14, with the air being discharged at 578°K (580°F) and the helium at 398°K (256°F). The helium was assumed to have been cooled to 366°K (200°F) in a precooler. Physically, the precooler need only constitute some banks of finned tubes carrying cooling water and placed after the steam cycle economizer tubes in the vapor generator. The heat rejected to sink is increased accordingly.

Since the amount of extra cooling would be different for the various cases, results would be hard to interpret. In order to relate the various cases to one another, the effectiveness values with which the available energy of the turbine exhaust streams was transmitted to the bottoming fluid were calculated as:

$$\varepsilon = \frac{B_{Bottom}}{B_{PU} + B_{He}} \tag{7.9}$$

For the bottom fluid, B could be calculated from tabulated thermodynamic properties.

$$B = \Sigma \dot{W}_i \Delta b_i \tag{7.10}$$

where $\dot{W}_i$ = mass flow rate

b_i = $h-T_oS$

B_{Bottom} = transmitted to bottom fluid

B_{PU} = available in pump-up turbine exhaust

B_{He} = available in helium turbine exhaust.

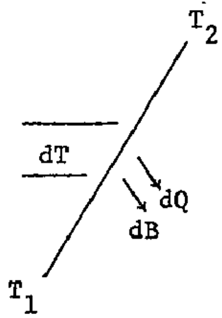
in which T_o was taken as the condenser temperature.

For the turbine exhaust streams, the values of B were calculated separately for each from the equation derived below.

Assume linear availability of heat (constant C_p) over a small temperature difference:

$$dq = \dot{W}\ dh = \dot{W}\ C_p\ dT$$

$$Q = \dot{W}\ C_p \int_{T_1}^{T_2} dT = \dot{W}\ C_p\ (T_2 - T_1) \qquad (7.11)$$



$$dB = (\eta\ \text{carnot})(dQ) = \left(1 - \frac{T_o}{T}\right) \dot{W}\ C_p\ dT$$

$$B = \dot{W}\ C_p \left[\int_{T_1}^{T_2} dT - T_o \int_{T_1}^{T_2} \frac{dT}{T}\right] \qquad (7.12)$$

$$B = W\ C_p \left[\left(T_2 - T_1\right) - T_o\ \ln\left(\frac{T_2}{T_1}\right)\right]$$

$$B = Q \left[1 - \frac{T_o}{\left(T_2 - T_1\right)}\ \ln\left(\frac{T_2}{T_1}\right)\right] \qquad (7.13)$$

7.3.4 Heat Exchanger Design Procedures

Since the use of surface heat exchangers is central in these closed-cycle concepts, the resultant pricing of such equipment has a major impact upon assessing the overall viability of the concept. Unfortunately, the majority of the heat exchangers involved (helium pressurized furnaces, heat recovery vapor generators, intercoolers, and recuperators) are not in widespread commercial use and, of necessity, the approach to pricing and concept design must be somewhat arbitrary. Given below is a description of the design procedures used for sizing this type of heat exchanger.

Due to the single-phase flow nature and relatively high pressures encountered in these exchangers a shell-and-tube design was adopted. For a given heat transfer rate, $\dot{Q}$, a specific pressure drop, and cycle-determined fluid temperatures, the first step was to select suitable tube configurations for the conditions involved. Then, using published correlations for internal heat transfer and pressure drop, as well as external correlations (Reference 7.13), the following iterative calculation would be made:

1. Choose a tube velocity, V_t.
2. Compute

$$\Delta p_{tube} = 4f \frac{L_t}{D_t} \frac{\rho V_t^2}{2g} \qquad (7.14)$$

where $f = 0.046 (\rho V_t D_t/\mu)^{-0.2}$

L_t = tube length (arbitrarily chosen)

D_t = tube internal diameter

ρ = fluid density

μ = fluid viscosity.

3. Adjust V_t to conform to allowable pressure drop.

4. Compute

$$h_t = 0.023 \frac{k}{D_t} (Re)^{0.8} Pr^{0.333} \tag{7.15}$$

where k = fluid conductivity

$Re = \rho\ V_t\ D_t/\mu$ (Reynolds number)

$Pr = C_p\ \mu/k$ (Prandtl number).

5. Select a triangular, staggered-tube arrangement where the center-to-center distance, S_t, = $2D_o$.
6. Choose a maximum shell-side velocity.
7. Compute

$$\Delta P_s = \frac{f'\ (\rho\ V_s)^2\ N}{\rho\ (2.09 \times 10^8)} \tag{7.16}$$

where V_s = maximum shell-side fluid velocity

N = number of tube rows transverse to the flow

$$f' = \left[0.25 + \frac{0.118}{\left[\left(\frac{S_t}{D_o}\right) - 1\right]^{1.08}}\right]\left(\frac{\rho\ V_s\ D_o}{\mu}\right)^{-0.16}$$

where D_o = outside tube diameter.

8. Adjust V_s based on the assumed value of N and on the allowable shell-side pressure drop.

9. Compute

$$h_s = 0.33 \left(\frac{k}{D_o}\right)\left(\frac{\rho\ V_s\ D_o}{\mu}\right)^{0.6}\left(Pr\right)^{0.3} \tag{7.17}$$

10. Solve the following equation for A_t

$$\frac{LMTD}{Q} = \frac{1}{A_t}\left(\frac{1}{h_t} + \frac{a_{t-o}}{h_s} + \frac{Ta_{t-k}}{k_t}\right) \tag{7.18}$$

where LMTD = given log mean temperature difference

Q = given heat transfer rate

A_t = total area internal to tubes

a_{t-o} = ratio of tube internal area to external area per unit length

a_{t-k} = ratio of tube internal area to radial thermal conduction area per unit length of tubing

k_t = thermal conductivity of tubing metal

T = tube wall thickness.

11. From the tubing geometry, and knowing the total tube inside area required, compute the total length, L_t, of tubing needed.

12. Compute the total tube flow cross-sectional area, A_c, required from

$$\rho_t\ V_t\ (A_c) = \text{Total tube-side mass flow rate} \tag{7.19}$$

13. Knowing (A_c) and the tube inside diameter, compute the total number of tubes requires, N_t.

14. Compute the length of each tube from (L_t/N_t) = length of each tube.

15. Go back to step 2 with new values of L_t and N_t and repeat steps 2 to 14 until the desired accuracy if obtained.

16. Knowing the number of tubes and length of each tube, as well as the staggered arrangement, find internal shell diameter, D_s.

17. Finally, using the formula

$$t_s = \frac{P_s D_s}{2\sigma} \tag{7.20}$$

where t_s = shell wall thickness

D_s = shell vessel inside diameter

σ = allowable shell wall metal stress

P_s = shell design pressure.

the shell wall thickness was computed.

7.3.5 Definitions

Basic turbomachinery terms such as turbine inlet temperature, compressor pressure ratio, etc., and heat exchanger definitions such as throttle pressure, approach temperature difference, etc. are consistent with those given in Subsections 5.3 and 6.3 of this report.

7.4 Results of the Parametric Study

7.4.1 Recuperative System of Parametric Point Identification

Table 7.4 presents a detailed listing of the recuperated system parametric point numbers and lists the results of the thermodynamic efficiency calculations.

FOLDOUT FRAME 1

FOLDOUT FRAME 2

Table 7 4—Recuperated Closed Cycle Gas Turbine Parametric Point Description

Pt No	Description ①	Pump up ②			Helium ③										Furnace					Cycle			Pt No
		T_4 Turbine Inlet Temperature, °F	ρ Compressor Pressure Ratio	Power Output ④, MW	T_3 Turbine Inlet Temperature °F	ρ Compressor Pressure Ratio	T_1 Compressor Inlet Temperature, °F	q_{HX} ⑤ Btu/lb	q_{PC} ⑥ Btu/lb	q_{add} ⑦ Btu/lb	q_{add} ⑧ Btu/lb	Mass Flow (m) lb/s	H_{wk} ⑨ Btu/lb	Power Output ④ MW	Fuel	HHV, Btu/lb	Fuel Air Ratio $m_f/\dot{m}_a$	η_B Burner Efficiency	q_{add} ⑩ MW	Gross Power, MW	Thermodynamic Efficiency, η	Equivalent Heat Rate (HR), Btu/kwh	
R 1	Vary He T & p, ϵ_{PU} = 0.90	2200	10.0	111.96	1200	2.0	96.5	634.0	326.4	604.9	478.3	1138.2	151.89	176.02	Distillate	13700	0.0529	1.00	939.335	287.98	0.3066	11130	R 1
R 2						2.5		431.8	402.6		581.9	935.6	179.30	170.79						282.75	0.3010	11335	R 2
R 3						3.0		266.2	472.4		659.3	825.7	186.93	157.16						269.12	0.2865	11910	R 3
R 4						4.0		2.0	597.6		769.0	707.9	171.49	123.60						235.56	0.2508	13606	R 4
R 5					1500	2.0		902.5	356.2		581.8	935.6	225.60	214.91						326.87	0.3480	9805	R 5
R 6						2.5		679.8	430.1		706.0	771.2	275.80	216.55						328.51	0.3497	9757	R 6
R 7						3.0		498.6	498.2		799.0	681.4	300.74	208.64						320.60	0.3413	9997	R 7
R 8						4.0		211.7	627.9		931.3	584.6	310.43	184.76						296.72	0.3159	10802	R 8
R 9					1800	2.0		1171.0	356.1		685.4	794.3	299.31	242.06						354.02	0.3769	9054	R 9
R10						2.5		927.7	457.7		830.0	655.9	372.29	248.62						360.58	0.3839	8889	R10
R11						3.0		731.0	524.0		938.6	580.0	414.55	244.82						356.78	0.3798	8984	R11
R12						4.0		421.4	644.2		1093.6	497.8	449.38	227.78						339.74	0.3617	9434	R12
R13	ϵ_{PU} = ϵ_{He} = 0.80				1500	2.0		892.2	456.5	591.8	682.1	780.8	225.60	179.35						291.31	0.3101	11002	R13
R14	0.95							952.6	306.1	611.5	531.7	1035.0		237.74						349.70	0.3723	9165	R14
R15	0.80					2.5		604.2	505.7	591.8	781.5	681.6	275.80	191.38						303.34	0.3229	10566	R15
R16	0.95							717.5	392.4	611.5	668.2	823.6		231.28						343.24	0.3654	9338	R16
R17	0.80					3.0		443.2	553.6	591.8	854.4	623.4	300.74	190.89						302.85	0.3224	10583	R17
R18	0.95							526.3	470.5	611.5	772.2	713.6		218.50						330.46	0.3518	9699	R18
R19	0.80					4.0		188.2	644.2	591.8	954.8	557.8	310.43	176.31						288.27	0.3069	11119	R19
R20	0.95							223.5	609.1	611.5	919.5	598.5		189.17						301.13	0.3206	10644	R20
R21	Ill No. 6 Coal, ϵ_{PU} = 0.90	1700	5.0	75.96		2.5		679.8	430.1	746.0	706.0	951.1	275.80	267.06	Ill No.6	12028	0.0849	0.96	969.671	343.02	0.3537	9646	R21
R22			10.0	88.97						707.4		901.8		253.24						337.21	0.3477	9812	R22
R23	Ill No. 6 Coal		5.0	78.66						593.6		756.8		212.50						291.16	0.3003	11364	R23
R24			15.0	83.16						678.5		865.0		242.90						326.06	0.3363	10147	R24
R25 Base	Ill No. 6 Coal	1700	10.0	86.13	1500	2.5	96.5	679.8	430.1	644.1	706.0	821.1	275.80	230.58	Ill No 6	12028	0.0849	0.96	969.671	316.71	0.3266	10447	R25 Base
R26	Ill No 6 Coal	1100		37.53						882.7		1125.3		316.00			0.0908		1037.057	353.53	0.3409	10009	R26
R27	Sub Bituminous Coal			42.66						863.9		1101.4		309.27	Sub Bitum	9452	0.1165		1045.618	351.93	0.3366	10138	R27
R28	Lignite			47.34						833.8		1063.0		298.49	Lignite	7946	0.1380		1041.240	345.83	0.3321	10273	R28
R29	High Btu Gas			45.99						965.0		1230.2		345.46	High Btu Gas	22550	0.0561	1.00	1201.227	391.45	0.3259	10471	R29
R30	Low Btu Gas			35.28						927.0		1181.8		331.86	Low Btu Gas	12028	0.0980		1119.291	367.14	0.3280	10402	R30
R31	Vary He p			37.89		2.0		902.5	356.2	930.8	581.8	1439.8	225.60	340.70	Distillate	18700	0.0618		1097.371	368.59	0.3359	10159	R31
R32 Ref						2.5		679.8	430.1		706.0	1186.7	275.80	333.22						371.11	0.3382	10090	R32 Ref
R33						3.0		498.6	498.2		799.0	1038.5	300.70	321.05						358.94	0.3271	10432	R33
R34						4.0		211.7	620.9		931.3	899.5	310.40	284.30						322.19	0.2936	11621	R34
R35	Vary PU p		5.0	44.01		2.5		679.8	430.1	876.7	706.0	1117.7	275.80	313.95						357.96	0.3262	10460	R35
R36			15.0	27.27						967.6		1233.6		346.39						373.66	0.3405	10021	R36
R37	Dry Cooling Tower		10.0	37.89			120.0	641.1	440.7	930.8	701.5	1194.1	260.80	317.10						354.99	0.3235	10548	R37
R38	Once Through Cooling						79.0	709.3	422.3		709.2	1181.2	287.00	345.03						382.98	0.3490	9777	R38
R39	PU ΔP/P Furnace 0.09			36.00			96.5	679.8	430.1		706.0	1186.6	275.80	333.22			0.0617		1095.595	369.22	0.3370	10125	R39
R40	0.12			34.02																367.24	0.3352	10179	R40
R41	He ΔP/P 0.04			37.89				691.5	431.5		694.2	1206.8	262.70	322.82			0.0618		1097.371	360.71	0.3287	10381	R41
R42	0.06							703.5	432.8		682.2	1227.9	249.40	311.86						349.75	0.3187	10706	R42
R43	Intercooling ⑪					4.0		520.2	312.4		965.6	867.6	398.60	352.10						389.99	0.3554	9601	R43
R44						5.0		372.3	344.0		1065.4	786.3	418.80	335.29						373.18	0.3401	10034	R44
R45						7.0		160.0	397.5		1200.6	697.7	423.40	300.82						338.71	0.3087	11055	R45
R46	He P_4 = 500 psia	Same as R32 Reference																					R46
R47	2000 psia	Same as R32 Reference																					R47
R48 Base	Atmos Furnace, Ljungst Recup. ⑫	1100	1.0		1500	2.5	96.5	679.8	430.1	1023.0	706.0	1304.1	275.80	366.20	Distillate	15700	0.0617	1.00	1095.595	360.70	0.3292	10364	R48 Base

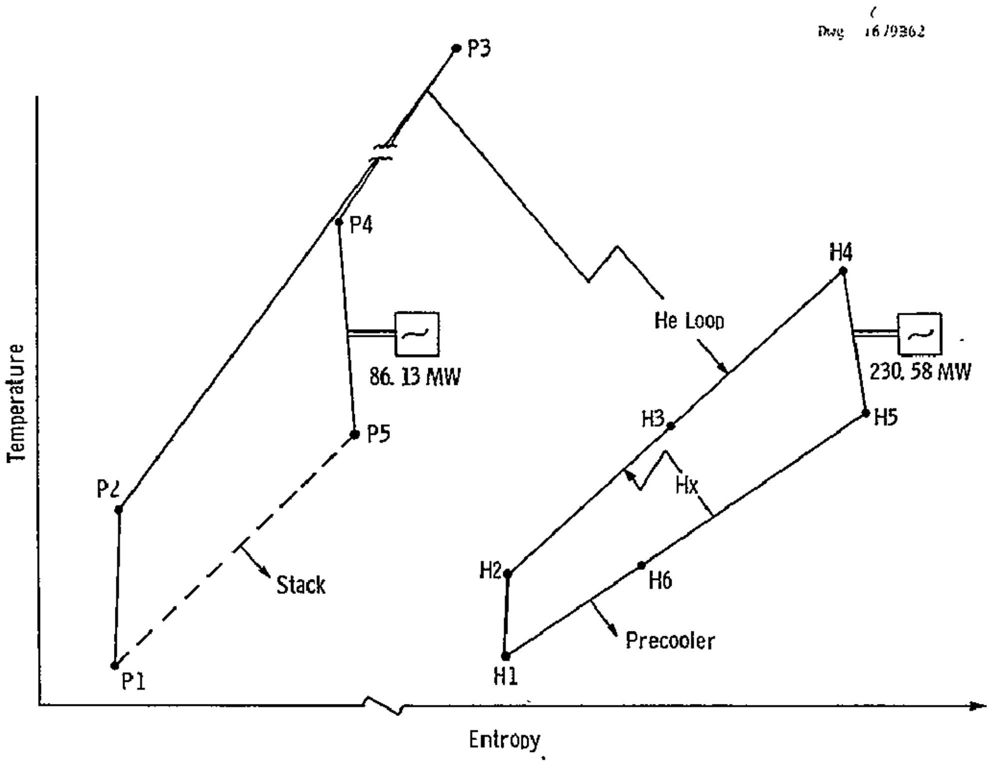
1. ϵ_{PU} = 0, ϵ_{He} = 0.90 Unless Noted
2. $\dot{m}_{PU}$ = 900 lb/s
3. Helium c_p = 1.24 Btu/lb °F, γ = 1.6668
4. MW = $(m)(H_{wk})(0.965)(3600)(3417500)$ Where 0.965 Is for the Mechanical and Generator Loss
5. Recuperator Heat Exchange Referred to Helium Flow
6. Precooler Heat Rejection Referred to Helium Flow
7. Primary Heat Addition Referred to Pump-up Air Flow
8. Primary Heat Addition Referred to Helium Flow
9. Helium Turbine Output Referred to Helium Flow
10. Total Primary Heat Input Expressed in MW = $[\dot{m}_f/\dot{m}_a](900)(HHV)(3600)/(3412750)$
11. Intercooler: q = 254.6, 302.6, 379.7 for Pts 43, 44, 45
12. Air Circuit Consists of Ljungstrom Recuperator and Fan, Temp. In and out of Recuperator (Hot Side) 1100, 290°F, Fan Power 5.5 MW

For Points R1 through R12, the basic closed-cycle parameters of helium turbine inlet temperature and compressor pressure ratio were varied. Pressure ratio values of 2 to 1 through 4 to 1 were used in conjunction with turbine inlet temperature values of 922 through 1255°K (1200 to 1800°F). For all of these calculations, the pump-up gas turbine inlet temperature was 1478°K (2200°F), and its compressor pressure ratio was 10 to 1. A recuperator effectiveness value of 0.90 was chosen for both the pump-up turbine and the helium gas turbine subsystems. In Points R13 through R20, variations in the recuperator effectiveness were made simultaneously over the range 0.80 to 0.95 for both the pump-up cycle and the helium cycle gas turbine. Variations of the assumed fuel were made in Points R21 through R30. Included were the use of pressurized fluid bed combustion of bituminous, subbituminous, and lignite coals as well as the uses of high- and low-Btu gas. These points all have helium turbine inlet temperatures of 1089°K (1500°F), a helium compressor pressure ratio of 2.5, and recuperator effectiveness values equal to 0.9. Points R21 and R22 investigated the variation of the pump-up cycle compressor ratio at values of 5 to 1 and 10 to 1 with recuperator effectiveness values of 0.90. For Points R23 and R24, the same pressure ratios were used but without a pump-up recuperator. Point R25, Base Case A, was fired with Illinois No. 6 bituminous coal in connection with a pump-up gas turbine inlet temperature of 1200°K (1700°F), a compressor pressure ratio of 10 to 1, and no pump-up recuperator. For Points R26 through R30, a pump-up turbine inlet temperature of 866°K (1100°F) was used, thereby transferring more heat directly to the helium cycle; and the three coals as well as high- and low-Btu gas fuels were considered. In Points R31 through R36, variations were made in compressor pressure ratio for each cycle: 2, 2.5, 3, and 4 to 1 for the helium cycle, and 5 and 15 to 1 for the pump-up cycle, respectively. These calculations were made with a pump-up turbine inlet temperature of 866°K (1100°F) and no recuperation and a helium turbine inlet temperature of 1088°K (1500°F) with 0.9 recuperator effectiveness. Points R37 and R38 investigate dry cooling tower and once-through heat rejection of the heat picked up from the helium in the precooler. In Points R39 and R40, the effect of increasing the pump-up cycle furnace pressure drop ratio from the base case value of 0.06 to 0.09 and 0.12 was investigated. Similarly, the effect of increasing the helium heat exchanger pressure drop ratio from the base case value of 0.02 to 0.04 and 0.06 was investigated in Points R41 and R42, respectively. Helium compressor intercooling was considered in Points R43 through R45 and helium compressor pressure ratios of 4, 5, and 7 to 1 were used, respectively. The effects of varying helium cycle top pressure have been investigated with the nominal 6.895 MPa (1000 psi) abs replaced by 3.447 and 13.790 MPa (500 to 2000 psi) abs in Points R46 and R47, respectively. Point R48 corresponds to Base Case B and differs principally from Base Case A in the use of an atmospheric pressure furnace with a Ljungstrom-type regenerator. Distillate fuel derived from coal was used, and the helium cycle principal parameters were 1089°K (1500°F) turbine inlet temperature, a 2.5 to 1 compressor pressure ratio, and a 0.9 recuperator effectiveness.

7.4.2 Recuperative System Base Case Results

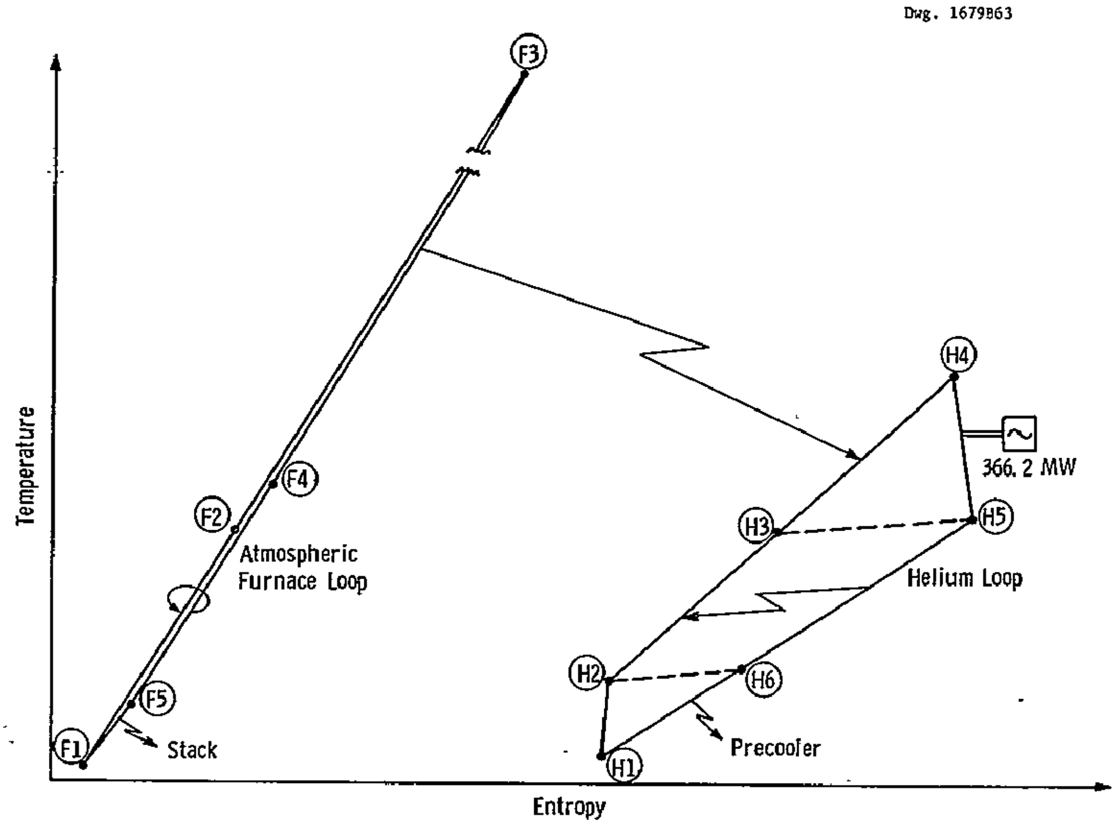
The Base Case A cycle schematic diagram has been shown previously in Subsection 7.2 (Figure 7.3). Selected thermodynamic data results for this cycle are given in Figure 7.15. The overall cycle efficiency for this arrangement has been calculated to be approximately 32%, with a net output of just over 300 MW in the single pump-up turbine, single helium turbine configuration.

Base Case B, utilizing the atmospheric pressure furnace, is illustrated schematically by Figure 7.5 of Subsection 7.2. Both a schematic temperature-entropy diagram and tabulation of selected cycle data for Base Case B are given in Figure 7.16. This cycle arrangement with a single helium turbine having an inlet temperature of 1089°K (1500°F) delivers approximately 350 MW at 32.5% overall thermal efficiency.



Station	Pressure, psia	Temperature, °F	Flow, lb/s
Pump-Up (pressurizing) Gas Turbine Cycle			
P1	14.696	59.0	900.0
P2	147.0	615.0	
P3		3620.0	976.7
P4	133.8	1700.0	
P5	14.7	910.0	
Helium Gas Turbine Cycle			
H1	400.0	96.5	821.1
H2	1000.0	382.5	
H3	990.0	930.7	
H4	970.2	1500.0	
H5	412.3	991.6	
H6	408.2	443.4	

Fig. 7.15—Summary of thermodynamic cycle data (recuperative cycle Base Case A, Point R25)



Station	Pressure, psia	Temperature, °F	Flow, lb/s
Atmospheric Furnace Cycle			
F1	14.7	59.0	900.0
F2		937.0	
F3		3800.0	955.5
F4		1100.0	
F5		290.0	
Helium Gas Turbine Cycle			
H1	400.0	96.5	1304.1
H2	1000.0	382.5	
H3	990.0	930.7	
H4	970.2	1500.0	
H5	412.3	991.6	
H6	408.2	443.4	

Fig. 7.16—Summary of thermodynamic cycle data (recuperative cycle Base Case B, Point 48)

7.4.3 Recuperative System: Results of Parametric Variations[*]

Figures 7.17 through 7.23 and Figures 7.24 through 7.30 show the effects of the various parameters on the thermodynamic cycle efficiency and gross cycle power. Note that the trends described by the efficiency curves and by the power curves are the same for each value of pump-up temperature and fuel as, for each value, the cycle heat added is constant; e.g., Figures 7.17 and 7.24 show a similar trend as the pump-up temperature and fuel is the same for all curves, but Figures 7.19 and 7.26 do not show the same trend, as the pump-up temperature and fuel vary from curve to curve.

At constant heat added, the efficiency is directly proportional to the power; also, the efficiency is directly proportional to the specific power, as the airflow is always 408 kg/s (900 lb/s). For this reason the curves are not plotted in terms of specific power and efficiency, which would give a single straight line for each value of pump-up temperature and fuel.

The efficiency is taken with respect to the higher heating value of the fuel. The plant electrical output is corrected for the mechanical and generator loss.

Figure 7.17 shows the effect of helium temperature and pressure ratio on the cycle efficiency. The contribution of the helium loop to the cycle performance is roughly as follows. The helium loop produces roughly 60, 66, and 69% of the power; and the loop efficiency is roughly 31, 39, and 45%, at helium turbine inlet temperatures of 922, 1089, and 1255°K (1200, 1500, and 1800°F), respectively, at 2.5 to 1 pressure ratio. Also shown is the combined effect of the pump-up and helium recuperator effectiveness which were varied from 0.8 to 0.95 for a helium turbine inlet temperature of 1089°K (1500°F).

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[*] The results listed in Table 7.4 and figures shown below apply to thermodynamic efficiency and corresponding gross power output before related station auxiliary powers were deducted.

[illegible]

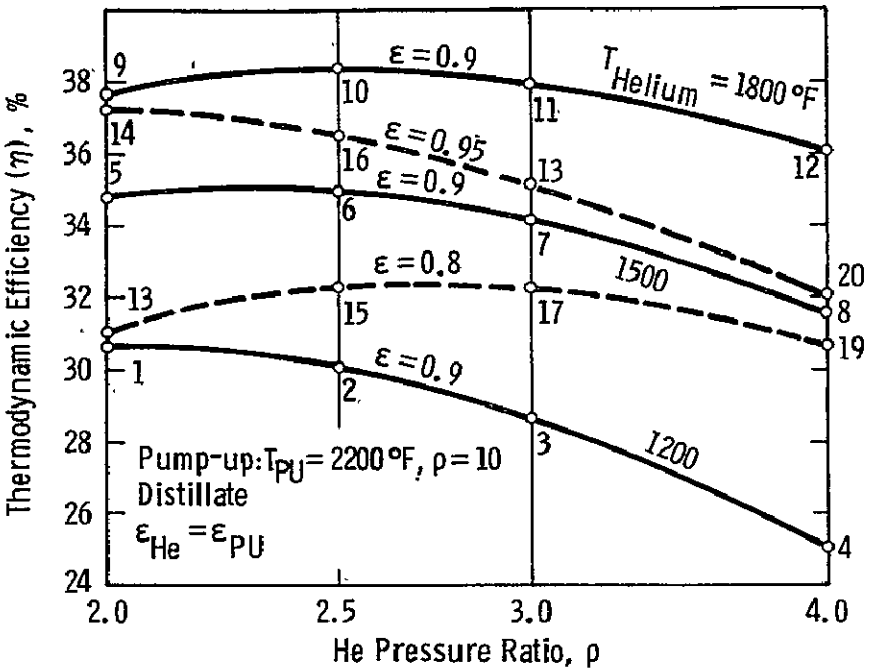
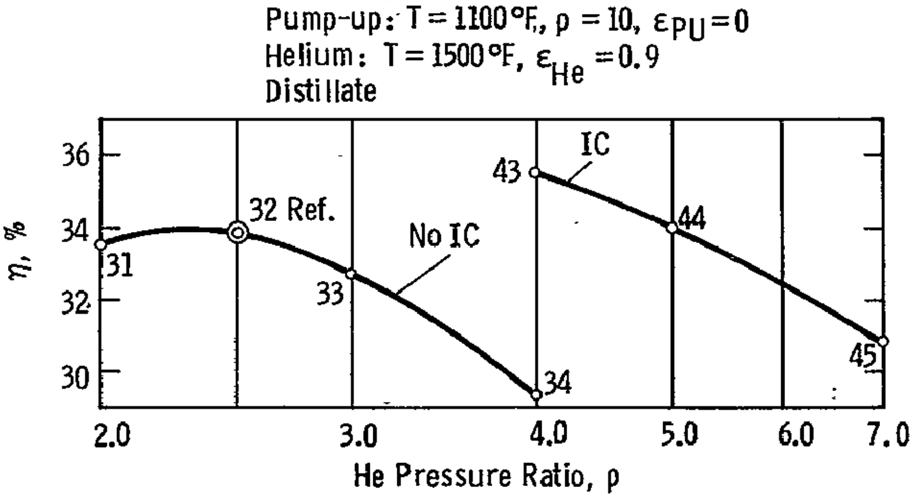


Fig. 7.17—Influence of helium temperature and pressure ratio



Influence of intercooling

Fig. 7.18—Recuperated closed-cycle efficiency, ISO ambient

Curve 680325-B

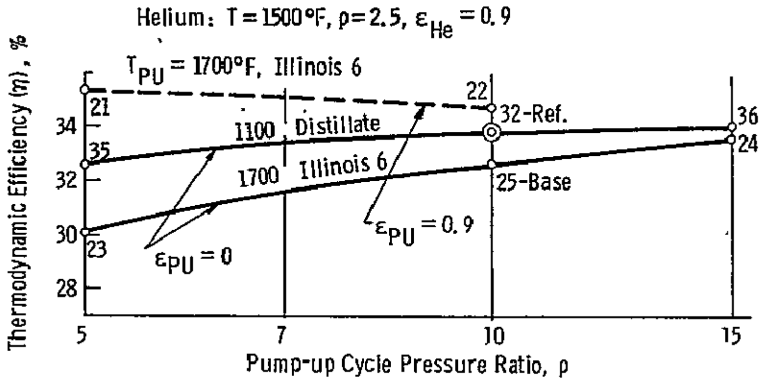


Fig. 7.19 – Influence of pump-up temperature and pressure ratio

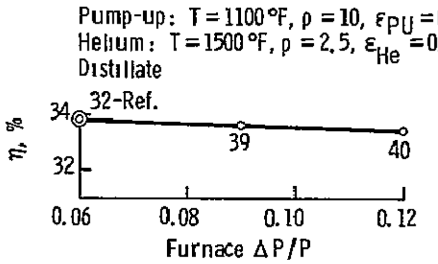


Fig. 7.20 – Influence of air pressure loss

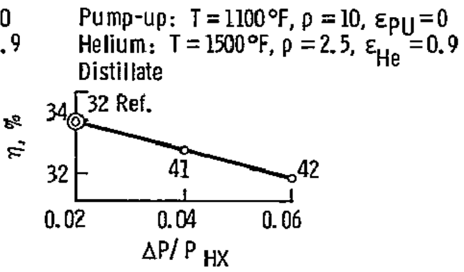


Fig. 7.21 – Influence of helium pressure loss

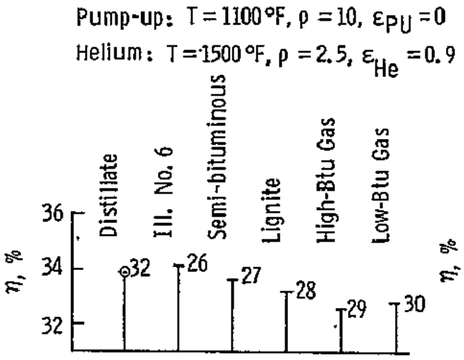


Fig. 7.22 – Influence of fuels

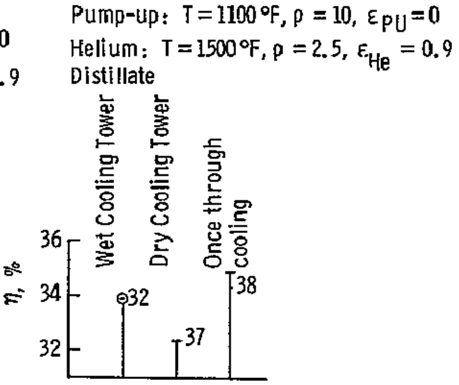


Fig. 7.23 – Influence of type cooling tower

Recuperated closed-cycle efficiency, ISO ambient

In Figure 7.17, the pump-up temperature is 1478°K (2200°F) and the pump-up recuperator is included. But in the following curves, Figures 7.18 through 7.23, pump-up temperatures of 1200 and 866°K (1700 and 1100°F) were used, and the pump-up recuperator was not included (with the exception of the dashed line curve, Figure 7.19).

Figure 7.18 shows the effect of intercooling, approximately a 1-1/2 point gain in efficiency. This comparison was made at different pressure ratios.

The parametric variations displayed in Figures 7.18 through 7.23 use Point R32 as a base or reference condition. Here[**], the pump-up temperature and pressure ratio are 866°K (1100°F) and 10 to 1; the helium temperature and pressure ratio are 1089°K (1500°F) and 2.5 to 1. No pump-up recuperator was used, and a 0.90 helium recuperator effectiveness was assumed. Most cases were assumed to fire a coal-derived distillate fuel. Point R25 (Base Case A) is the same as the Point R32 reference except that the pump-up temperature was 1200°K (1700°F) and the fuel was Illinois No. 6 coal.

Figure 7.19 shows the effect of pump-up temperature and pressure ratio. The two solid line curves for 1200 and 866°K (1700 and 1100°F) show approximately a one-point improvement in efficiency at 866°K (1100°F) at a 10-to-1 pressure ratio. The improvement is due to the larger percentage of work in the more efficient helium loop at 866°K (1100°F), although the improvement is somewhat offset by the drop-off in pump-up efficiency at the lower temperatures.[*] This ignores the difference in fuel at the two temperatures, but this probably has little effect (see Figure 7.22). The effect of pump-up recuperation is shown by the solid and dashed line curves for 1200°K (1700°F) to be in the order of two points at a 10-to-1 pressure ratio. Finally, by comparing Point R22 with Point R6 of Figure 7.17, it is shown that the efficiency is

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[*] At low pump-up temperature, more heat is absorbed by the helium in reducing the furnace air to the lower temperature and, hence, more heat is added to the helium cycle.

[**] Point R32

approximately the same at 1200 and 1478°K (1700 and 2200°F) pump-up temperature. Here the stand-off is due to the counteracting effects of the work shift to the more efficient helium cycle and the drop-off in the pump-up efficiency at 1200°K (1700°F).

As a rough guide to the work shift referred to above, 2/3, 3/4, and 9/10 of the total power is produced by the helium loop at 1478, 1200, and 866°K (2200, 1700, and 1100°F) pump-up temperature for the reference helium conditions of 1089°K (1500°F) and a 2.5-to-1 pressure ratio.

Figures 7.20 and 7.21 show the effect of pressure loss in the pump-up and helium circuit. Because of the low-pressure ratio, the pressure loss in the helium loop has a greater effect. Note that the pressure drop in the recuperator is the combined pressure loss for the hot and cold side.

The effect of fuel type on efficiency is shown by Figure 7.22. In Points R32, R26, R27, and R28 for distillate and coals, the spread is in the order of one-half percentage point. For Points R29 and R30 which used high- and low-Btu gas, respectively, the main factor behind the differing efficiency results is the approximate 10% difference in the fuel higher and lower heating values (compared with about 5% for distillate). This larger difference for the fuel gases is associated with their high hydrogen content. This means that a larger amount of the heat added is unavailable for work in the pump-up turbine. Note, also, that the efficiency of the low-Btu gas case allows for the energy requirements of the coal gasification plant.

The efficiency differences associated with the precooler temperature are shown in Figure 7.23. With wet, dry, and once-through cooling, water temperatures of 292.3, 305.4, and 282.6°K (66.5, 90, and 49°F) were assumed. With a 16.7°K (30°F) approach temperature, the helium was assumed to have been cooled to 309, 322, and 299°K (96.5, 120, and 79°F).

The power curves in Figures 7.24, 7.25, 7.27, 7.28, and 7.30 have trends identical to those displayed by the corresponding efficiency

Curve 680327-A

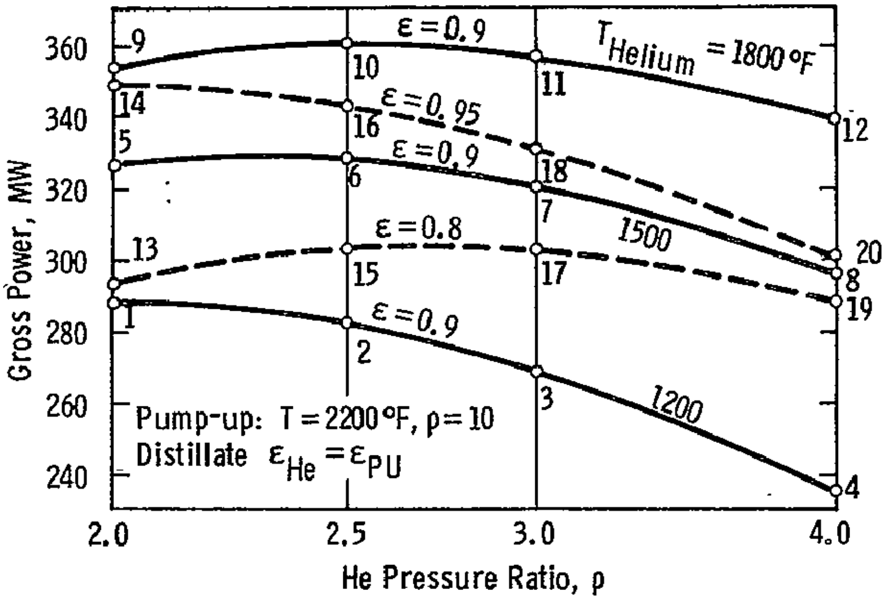


Fig. 7.24—Influence of helium temperature and pressure ratio

Pump-up: T = 1100 °F, ρ = 10, $\varepsilon_{PU} = 0$

Helium: T = 1500 °F, $\varepsilon_{He} = 0.9$, Distillate

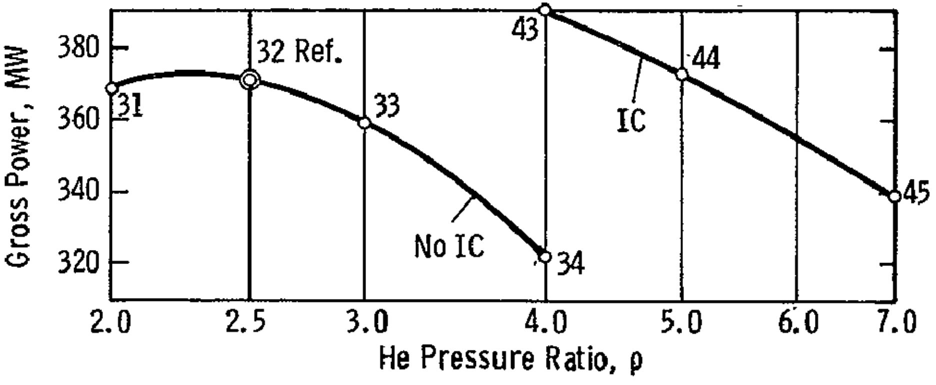


Fig. 7.25—Recuperated closed-cycle power, ISO ambient

curves. The heat added is constant with respect to all points on each of these curves; hence, the efficiency changes are proportional to the power changes. In Figures 7.26 and 7.29 there is a variation in heat added from point to point associated with the difference in pump-up temperature and fuel. At low pump-up temperature, more heat is absorbed by the helium in reducing the furnace air to the lower temperature.

The heat of combustion per pound of air is highest for high-Btu gas, intermediate for distillate and low-Btu gas, and lowest for the three coals. Furthermore, the coals are assumed to burn with a 4% combustion loss reducing their effective heating still further, whereas the gases and distillate are assumed to burn completely. Thus, as the airflow was assumed constant, the heat added drops off in the order named (at fixed pump-up temperature). This accounts for the difference in Figures 7.26 and 7.29 with respect to the corresponding efficiency curves. Note in Figures 7.19 and 7.26 the shift in the dashed line curve with respect to the solid line curves and the change in spread of the solid line curves. This is associated with the lower heat addition at 1200°K (1700°F) and the higher heat addition with distillate fuel. Note also, in Figures 7.22 and 7.29, that the power is affected more by the change in heat addition (highest with high-Btu gas, intermediate with distillate and low-Btu gas, and lowest with coals) than by the change in efficiency.

Point R48, Base Case B, is for an atmospheric combustion subsystem. Atmospheric pressure air is supplied to the furnace by a fan. A Ljungstrom regenerator preheats the furnace air. By comparison with Point R25, Base Case A, the efficiency is roughly the same, but the power is approximately 16% higher.

7.4.4 Combined System Parametric Point Identification

A tabulation of the combined system parametric variations including parametric point numbers and thermodynamic efficiency results is given in Table 7.5.

The first group, including Points C1 through C9, has been selected for variation of the helium cycle turbine inlet temperature and

Curve 680322-B

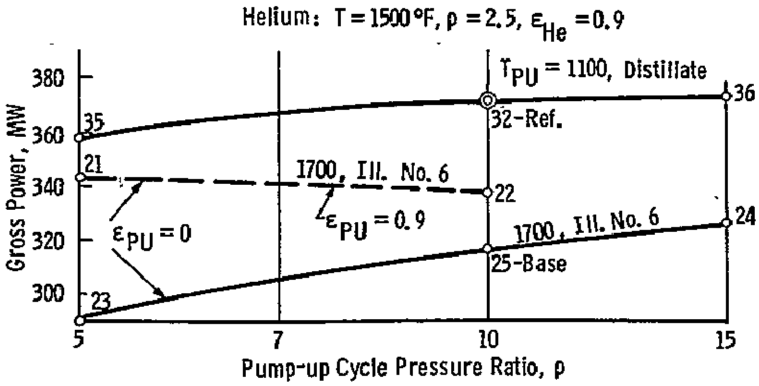


Fig. 7.26—Influence of pump-up temperature and pressure ratio

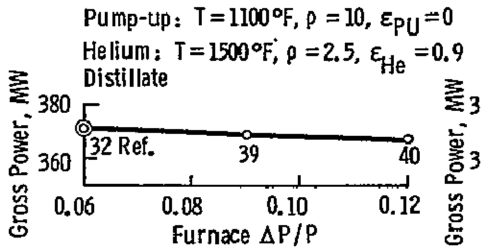


Fig. 7.27—Influence of air pressure loss

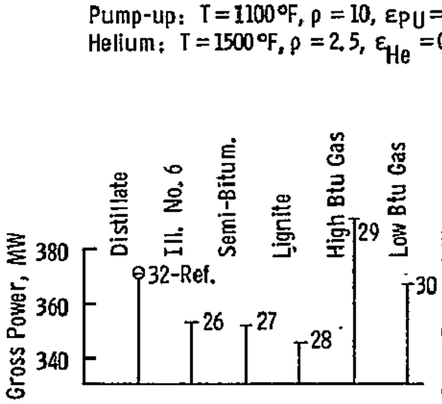


Fig. 7.29—Influence of fuels

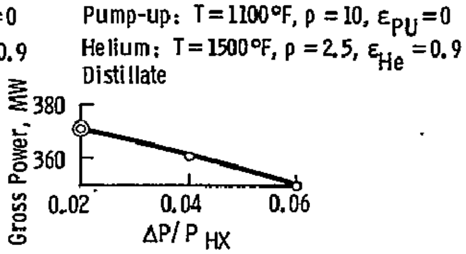


Fig. 7.28—Influence of helium pressure loss

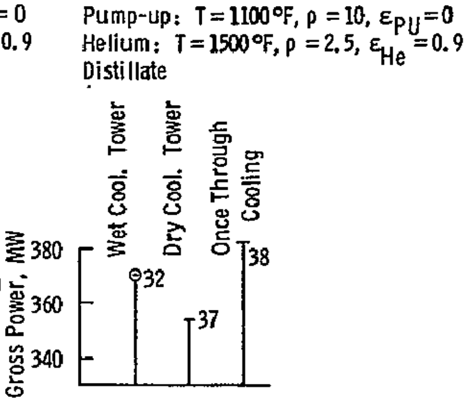


Fig. 7.30—Influence of type cooling tower

·Recuperated closed-cycle power, ISO ambient

Table 7.5—Combined Closed Cycle Gas Turbine Parametric Point Description

[illegible]

Pt. No.	Description	Pump-up Cycles① T_4 Turbine Inlet Temperature °F	p Compressor Pressure Ratio	T_5 Turbine Exhaust Temperature °F	T_6 Stack Temperature °F	Q_{air} VG ④ $= \dot{m}(c_p)(a)(T_5 - T_6)$ Btu/sec	Power Output ⑤ MW
C1	Vary He T & p	2200	10	1193	570.0	158900	112.77
C2					690.0	128290	
C3					680.0	130800	
C4					555.0	162770	
C5 Base					580.0	156300	
C6					650.0	136500	
C7					425.2	195800	
C8					511.0	173900	
C9					600.0	151200	
C10	Without Air/Steam VG			1180	–	–	134.57
C11		1700		889	–	–	87.30
C12		1100		493	–	–	37.89
C13	He T_1 = 150°F	2200		1193	571.0	158600	112.77
C14	250				593.0	153000	
C15	300				552.7	163600	
C16	350				453.3	184800	
C17	Precooler, He T_1 = 200°F				552.0	163720	
C18	250				529.3	169300	
C19	300				452.2	188900	
C20	350				375.0	208600	
C21	Without Steam Reheat				655.0	137200	
C22					621.0	145900	
C23	Vary Pump-up T & p		15	1032	409.0	119730	133.67
C24		1700	5	1097	470.0	109900	77.67
C25			10	931	673.0	57900	84.87
C26	Pinch Pt. 40°F	2200		1193	637.0	141800	112.77
C27	80				662.0	130300	
C28	He ΔP/P Furnace = 0.04				558.0	162000	
C29	0.06				545.0	160200	
C30	He ΔP/P VG = 0.04	2200	10	1193	558.0	152000	112.77
C31	0.06				565.0	162200	
C32	Pump-up ΔP/P Furn. = 0.03			1183	548.0	151700	115.47
C33	0.09			1203	572.0	162700	109.96
C34	0.12			1214	569.0	164700	107.30
C35	Pump-up ΔP/P VG = 0.02			1186	579.0	154800	114.57
C36	0.06			1197	578.0	155600	110.97
C37	He P_4 = 500	Same as Pt. 5 Base					
C38	2000	Same as Pt. 5 Base					
C39	High-Btu Gas	2200	10	1200	575.0	164400	124.54
C40	Low-Btu Gas			1135	574.0	157500	117.72
C41	Illinois No. 6 Coal	1700		930	685.0	57800	84.33
C42	Sub-Bituminous Coal			936	670.0	65300	90.63
C43	Lignite			939	652.0	72700	96.66
C44	Dry Cooling Tower	2200		1193	580.0	156300	112.77
C45	Once Through Cooling				580.0		
C46	R12				290.0		
C47	"						
C48	Methyl Amine			802		127100	130.36
C49	" "	1700		573		53300	35.46
C50	" "	2200		802		177300	130.36
C51	" "						
C52	SO_2			1193	347.0	215800	112.77
–	1 1/2 in. Hg Cond. Press.	Same as Pt. 45					
–	2 in.	Same as Pt. 5 Base					
–	2 1/2 in.	2200	10	1193	580.0	156300	112.77
–	3.5 in.	Same as Pt. 44					
–	4.0 in.	2200	10	1193	580.0	156300	112.77

Pt. No.	Helium② T_3 Turbine Inlet Temperature °F	p Compressor Pressure Ratio	T_4 Turbine Exhaust Temperature °F	Supplementary or Precooler Inlet Temperature (T_9), °F	CTX VG ⑥ $= (c_p)(\dot{m})(T_4 - T_9)$ Btu/s	Qcooler ⑦ $= (c_p)(\dot{m})(T_9' - T_1)$ Btu/s	Compressor Inlet Temperature (T_1), °F	q_{add} ⑧ Btu/lb a	q_{add} ⑨ Btu/lb He	Mass Flow $(\dot{m})$ lb/s	H_{nk} ⑩ Btu/lb He	Power Output ⑤ MW
C1	1200	1.5	1002.0	258.2	378400	29600	200.0	490.0	1074.7	410.33	90.20	33.51
C2		2.0	859.7	331.3	307290	76370			940.6	446.87	122.52	58.49
C3		2.5	758.9	409.0	252200	138700			824.0	535.19	151.95	71.35
C4	1500	2.0	1091.7	219.0	456777	7971			1512.6	355.98	198.78	65.03
C5 Base		2.5	979.2	256.1	337600	45600			1196.0	368.73	229.79	86.27
C6		3.0	888.7	285.5	302100	42800			1072.8	403.92	237.76	97.78
C7	1800	2.5	1199.5	200.0	344600	–			1548.0	281.25	326.64	94.11
C8		3.0	1095.2	230.8	334300	370			1463.8	301.47	351.77	108.51
C9		4.0	943.8	266.1	289300	29200			1282.2	344.21	358.92	125.78
C10	1500	2.5	979.2	421.6	254900	101300			1196.0	368.73	229.79	86.27
C11					309500	142700		691.0		519.99		121.66
C12					414300	192500		930.8		702.43		163.47
C13				246.7	330600	40800	150.0	490.0	1289.5	341.99	261.33	90.98
C14				260.8	354300	5420	250.0		1302.5	400.00	198.28	80.75
C15				300.0	368300	–	300.0		1049.0	437.08	166.76	74.21
C16				350.0	375800	–	350.0		915.5	481.73	135.25	66.33
C17			984.4	235.9	294600	54800	96.5		1389.6	317.36	283.63	93.18
C18				250.0	279900	60400						
C19				300.0	269300	80100						
C20				350.0	249700	99800						
C21			979.2	245.1	335600	70600	200.0		1196.0	368.73	229.79	86.27
C22				273.5	343500	19720						
C23				259.9	345200	34000		521.6		392.51		91.83
C24				308.4	407900	64800		640.5		481.98		112.76
C25				300.6	435600	66800		651.0		519.98		121.65
C26				287.7	316400	39900		490.0		368.73		86.27
C27				331.0	296400	59900						
C28			989.8	252.0	337800	23300					216.44	82.33
C29			1000.7	242.7	344800	19300					233.12	76.25
C30	1500	2.5	989.8	252.0	337800	23300	200.0	492.0	1196.0	368.73	216.64	81.33
C31			1000.7	242.7	344800	19300					203.12	76.25
C32			979.2	253.7	331900	24300					229.79	86.27
C33				253.5	331800	24500						
C34				248.3	334200	22130						
C35				260.2	328700	27300						
C36				252.5	332300	24000						
C37												
C38												
C39	1500	2.5	979.2	247.5	345200	22420	200.0	505.6	1196.0	380.47	229.79	87.01
C40				244.5	314600	19100		458.9		345.32		80.79
C41				290.6	426700	54100		664.1		479.74		116.92
C42				284.6	401600	48900		619.6		466.25		109.08
C43				283.3	380300	49500		585.6		440.67		103.10
C44				271.6	323500	32700		490.0		368.73		86.27
C45				249.8	333500	22800						
C46				202.0								
C47												
C48			502.7	142.0	352500	–	140.0	607.6	697.8	783.68	248.08	197.492
C49					539900	–		930.8	697.8	1200.55		303.230
C50			527.2	158.0	360500	–	158.0	607.6	694.4	787.50	236.41	189.707
C51			502.7	140.0	352900	–	140.0		697.8	783.68	248.08	197.940
C52			979.2	202.0	354900	–	200.0	490.0	1196.0	368.73	229.79	86.267
–												
–												
–	1500	2.5	979.2	269.7	324400	51900	200.0	490.0	1196.0	368.73	229.79	86.27
–												
–	1500	2.5	979.2	294.1	312900	43300	200.0	490.0	1196.0	368.73	229.79	86.27

Pt. No.	Steam③ P/T Throttle psi/°F	P/T Reheat psi/°F	Mass Flow $(\dot{m})$ lb/s	H_{nk} ⑪ Btu/lb	Power Output ⑤ MW	Furnace Fuel	HHV, Btu/lb	$\dot{q}_f/\dot{m}_a$ Fuel Air Ratio	Burner Efficiency (η_B)	Q_{add} ⑫ MW	Cycle Gross Power MW	Thermodynamic Efficiency η	Equivalent Heat Rate (HR), Btu/kWh	Pt. No.
C1	3500/900	500/950	345.49	599.0	232.82	Distillate	18700.0	0.0529	1.00	939.335	357.10	0.3892	8775	C1
C2	2500/850	350/900	282.88	576.7	156.10						337.36	0.3591	9501	C2
C3	2000/800	250/850	238.17	553.7	134.27						318.39	0.3390	10067	C3
C4	3500/950	500/1200	331.78	627.1	215.83						372.60	0.4180	8164	C4
C5 Base	3500/900	500/950	313.52	599.0	191.20						390.24	0.4154	8213	C5 Base
C6	2500/850	350/900	286.22	576.7	168.06						378.60	0.4031	8466	C6
C7	3500/950	350/1050	330.14	649.4	216.28						425.36	0.4526	7534	C7
C8	3500/950	350/1000	311.86	635.3	202.54						423.84	0.4512	7562	C8
C9	3500/900	500/950	281.07	599.0	172.64						412.19	0.4377	7795	C9
C10	2500/850	350/900	165.62	576.7	97.24						298.01	0.3173	10752	C10
C11			233.55		137.13			0.0577		1024.568	346.09	0.3378	10101	C11
C12			314.60		184.72			0.0618		1097.371	386.49	0.3522	9688	C12
C13	3500/900	500/950	302.59	599.0	184.54			0.0529		939.335	388.30	0.4134	8254	C13
C14			326.82		199.32						392.81	0.4182	8159	C14
C15			342.30		208.74						395.74	0.4213	8099	C15
C16			360.98		220.25						399.25	0.4250	8029	C16
C17			295.05		179.94						385.89	0.4108	8306	C17
C18														C18
C19														C19
C20														C20
C21	1600/1000	–	335.40	507.5	171.30						372.34	0.3964	8608	C21
C22	1250/950	–	352.70	486.9	174.84						373.83	0.3980	8573	C22
C23	2500/850	350/900	301.99	576.7	177.32						382.82	0.4075	8372	C23
C24	3500/900	500/950	326.07	599.0	200.57			0.0577		1024.568	393.00	0.3816	8941	C24
C25	2000/800	250/850	323.15	553.7	182.51						389.04	0.3797	8986	C25
C26	3500/900	500/950	295.00	599.0	179.91			0.0529		939.335	378.95	0.4034	8458	C26
C27			275.05		167.74						364.73	0.3905	8738	C27
C28			319.66		194.95						389.05	0.4142	8238	C28
C29			326.00		198.82						388.84	0.4140	8243	C29
C30	3500/900	500/950	319.66	599.0	194.95	Distillate	18700.0	0.0529	1.00	939.335	389.05	0.4142	8238	C30
C31			326.00		198.82						387.84	0.4129	8264	C31
C32			311.89		190.21						391.95	0.4173	8177	C32
C33			317.32		193.52						389.37	0.4147	8229	C33
C34			321.17		195.87						389.21	0.4144	8234	C34
C35			311.34		189.88						390.21	0.4153	8275	C35
C36			316.02		192.73						389.97	0.4152	8219	C36
C37														C37
C38														C38
C39	3500/900	500/950	321.22	599.0	195.90	High Btu Gas	22542.8	0.0490	1.00	1027.722	429.48	0.3984	8564	C39
C40			301.90		185.34	Low Btu Gas	12028.0	0.0835		953.681	383.85	0.4025	8477	C40
C41	2000/800	250/850	317.85	553.7	179.19	Illinois No. 6		0.0649	0.96	959.671	380.44	0.3923	8699	C41
C42			306.25	553.7	172.65	Sub. Bitum.	9452.0	0.1090		978.303	372.36	0.3806	8965	C42
C43			297.14	553.7	167.51	Lignite	7946.0	0.1295		977.106	367.27	0.3759	9077	C43
C44	3500/900	500/950	313.52	567.21	181.20	Distillate	18700.0	0.0529	1.00	939.335	380.73	0.4048	8429	C44
C45				612.82	195.62						394.65	0.4201	8121	C45
C46	2500/700	–	5678.50	–	155.259						364.194	0.3877	8801	C46
C47		–	4230.00	–	127.753						326.794	0.3479	9807	C47
C48	2500/500	–	1112.70	–	105.336						413.436	0.4401	7753	C48
C49	2000/450	–	1593.00	–	111.091			0.0618		1097.371	449.715	0.4098	8326	C49
C50	2500/500	–	1250.3	–	100.183			0.0529		939.335	400.050	0.4259	8011	C50
C51		–	1182.7	–	105.334						413.436	0.4401	7753	C51
C52	2500/1000	–	2351.85	–	209.153						408.272	0.4345	7853	C52
–														–
–														–
–	3500/900	500/950	313.32	570.96	182.25	Distillate	18700.0	0.0529	1.00	939.335	381.29	0.4059	8406	–
–														–
–	3500/900	500/950	313.52	518.95	165.65	Distillate	18700.0	0.0529	1.00	939.335	364.[illegible]	0.3882	8789	–

NOTES:

① Pump-up ṁ = 900 lb/s

② He: c_p = 1.24 Btu/lb/°F, γ = 1.666

③ Pts. 46-52: Bottoming Fluid as Noted

④ Heat Transferred to Pump-up Vapor Generator

⑤ MW = (ṁ)(H_{nk})(0.965)(3600)/(3412750) Where 0.965 is for the Mechanical and Generator Loss

⑥ Heat Transferred to Helium Vapor Generator

⑦ Total Heat Transferred in the Helium Precooler and Supplementary Cooler

⑧ Primary Heat Addition Referred to Pump-up Air Flow

⑨ Primary Heat Addition Referred to Helium Flow

⑩ Helium Turbine Output Referred to Helium Flow

⑪ Δhk is Enthalpy Drop for the hp and lp Turbine Less the Feed Pump Enthalpy Drop

⑫ Total Primary Heat Input Expressed in MW $\left(\frac{q_f}{\eta_B}\right)(900)(HHV)\left(\frac{3600}{3412750}\right)$

compressor pressure ratio. The first three points utilized a helium turbine inlet temperature of 922°K (1200°F) with compressor pressure ratios of 1.5, 2, and 2.5 to 1. A pump-up gas turbine inlet temperature of 1477°K (2200°F) and a compressor pressure ratio of 10 to 1 were used for all nine points. Each was fired with coal-derived distillate fuel, and high-pressure reheat steam turbines were used to bottom both the pump-up and helium cycles. Points C4, C5 (Base Case), and C6 of this group incorporate a helium turbine inlet temperature of 1089°K (1500°F) and compressor pressure ratios of 2, 2.5, and 3 to 1, respectively. For the last three points of the group, the helium turbine inlet temperature was set at 1255°K (1800°F); and pressure ratios of 2.5, 3, and 4 to 1 were used. For Points C10 through C12 the pump-up set vapor generator was omitted and the pump-up turbine inlet temperatures of 1478, 1200, and 866°K (2200, 1700, and 1100°F) were used. All three cases assumed pump-up set compressor pressure ratios of 10 to 1. Helium compressor inlet temperatures of 339, 394, 422, and 450°K (150, 250, 300, and 350°F) were assumed for Points C13 through C16. Point C5 with a compressor inlet temperature of 366°K (200°F) is also a member of this sequence.

Points C17 through C20 contrast with these in that a precooler is added to bring the compressor inlet temperature to 309°K (96.5°F). The precooler rejects heat to a wet cooling tower and receives helium from the vapor generator discharge at temperatures of 366, 394, 422, and 450°K (200, 250, 300, and 350°F), respectively. It was intended that the Points C17 through C20 would be the only ones requiring a precooler. The compressor inlet temperatures of the other points were intended to be high enough that the compressor would accept helium directly from the vapor generator. Due to pinch-point problems discussed in Subsection 2.3.3, however, a cooler was required for all points except C7, C15, and C16 and the organic fluid points C46 through C52. For Points C21 and C22, nonreheat bottoming steam turbines of nominal steam conditions 11.032 MPa (1600 psi) gauge, 811°K (1000°F) and 8.618 MPa (1250 psi) gauge, 783°K (950°F) were used. Variations of pump-up cycle turbine inlet temperature and pressure ratio have been selected for Points C23, C24, and C25. The combinations were 1478°K (2200°F) and 15 to 1 for Point C23; 1300°K (1700°F) and 5 to 1 for Point C24; and 1200°K (1700°F) and 10 to 1 for Point C25. The helium vapor generator pinch-point temperature difference has been modified from the base value of 22°K (40°F) to 33 and 44°K (60 and 80°F) in Points C26 and C27. The effects of pressure drops have been identified for investigation in Points C28 through C36. Furnace pressure drop ratios of 0.04 and 0.06 were investigated in Points C28 and C29, as compared with the base case value of 0.02. Helium vapor generator pressure drop ratios of 0.04 and 0.06, respectively, were substituted for the base case value of 0.02 in Points C30 and C31. Furnace pressure drops of 0.03, 0.09, and 0.12 were used for Points C32, C33, and C34. These compare with the base case value of 0.06. The pump-up gas turbine vapor generator pressure drop variations of 0.02 and 0.06 (base case value was 0.04) were used for Points C35 and C36. The influence of helium cycle-top pressure has been identified for study in Points C37 and C38. Alternative values of 3.447 to 13.790 MPa (500 and 2000 psi) abs were compared with the base case value of 6.895 MPa (1000 psi) abs in Points C37 and C38, respectively. The use of alternative fuels was investigated in Points C39 through C43. Points C39 and C40 utilized high- and low-Btu (integrated gasification plant) coal-derived gases, respectively. Both use a helium cycle turbine inlet temperature of 1089°K (1500°F), a compressor pressure ratio of 2.5 to 1, and a pump-up cycle turbine inlet temperature of 1478°K (2200°F) with a 10-to-1 compressor pressure ratio. Fluidized bed combustion of Illinois No. 6 bituminous, subbituminous, and lignite were selected for Points C41, C42, and C43. With each the pump-up cycle turbine inlet temperature was set at 1200°K (1700°F), which is compatible with fluid bed operation. For Points C44 and C45, alternative cycle heat rejection modes were selected. Dry cooling towers were designated for Point C44 and the once-through cooling method for Point C45.

Alternative bottoming cycle fluids were identified for study in Points C46 through C52. The three fluids used in connection with the recuperated open-cycle studies (Section 5) were used here. These included R-12, methylamine, and sulfur dioxide. The outstanding properties of

R-12 are that it is nontoxic, nonflammable, and noncorrosive. It is used below the base case configuration of pump-up and helium cycles to constitute calculation Cycles C46 and C47. Since the turbine expansion end point lies far into the superheated region for R-12 for this cycle, Point C47 contains a desuperheating recuperator to help heat the feed liquids. This is to show the contrast with Cycle C46, which does not have such a desuperheater. The top temperature for both cycles is 644°K (700°F), which is higher than that usually used for R-12. However, the usual limits for the fluid are based on its use as a refrigerant, in which it is mixed with oil and may even contain some water. In the absence of these contaminants and in contact only with materials of construction, the fluorine stays fixed and the fluid remains stable to a higher temperature. This is the basis for the 644°K (700°F) application.

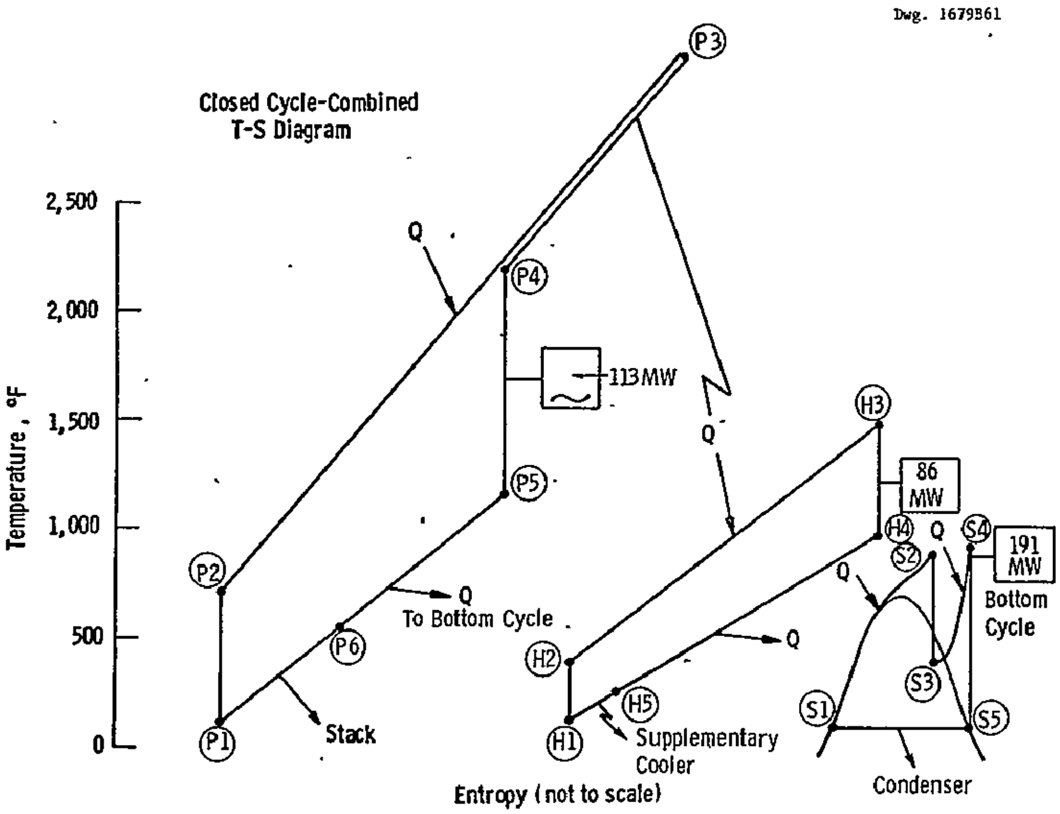
Cycles C48 through C51 have been formed by adding bottoming cycles to recuperated-type cycles. Since the required temperatures are low, the fluid could be chosen without much regard for chemical stability.

Methylamine was chosen as having good volume relations in the intermediate pressure range (TEAP of 3.96). It has a moderate critical pressure and could be fitted easily to the available heat lines.

Cycles C48 and C49 are subposed below the two types of recuperated cycle with pump-up turbine temperatures at 1478°K (2200°F) and 866°K (1100°F), respectively (similar to recuperated Cycles R6 and R32, respectively), for a basic comparison.

Cycle C50 rejects heat through a water circuit to a dry cooling tower and has a condenser temperature of 323°K (122°F). It compares with Cycle C48 which uses a wet cooling tower.

The low volume of the methylamine turbine exhaust allows one to consider deploying the bottom fluid directly to an air-cooled condenser (dry cooling tower). This avoids the thermodynamic losses associated with the use of an intermediate heat exchanger and the temperature range



Station	Pressure, psia	Temperature, °F	Flow, lb/s
Pump-up (Pressurizing) Gas Turbine Cycle			
P1	14.7	59.0	900
P2	147.0	615.0	
P3		3680.0	948
P4	138.2	2200.0	
P5	15.3	1193.0	
P6	14.7	530.0	
Helium Gas Turbine Cycle			
H1	400.0	200.0	369
H2	1000.0	535.0	
H3	980.0	1500.0	
H4	408.0	979.0	
H5		257.0	
Steam Bottoming Cycle			
S1	4375.0	107.0	314
S2	3500.0	900.0	
S3	571.0	481.0	
S4	500.0	950.0	
S5	(2 in Hg)	101.0	

Fig. 7.31 -Summary of thermodynamic cycle data (combined closed cycle base case, Point C5)

associated with the intermediate cooling-water loop. Cycle C51 has such an arrangement with a condenser temperature of 313°K (104°F). Since this is the same as Cycle C48, the thermodynamic performance will be identical. The comparison will center on the relative cost and ease of providing the different apparatus associated with the condensing vapor.

Cycle C52 is similar to Cycle C46, except that sulfur dioxide is used for the bottom cycle instead of R-12. The importance of sulfur dioxide is that is has high-temperature stability and thus permits the cycle to be adjusted to utilize the available energy from the pump-up and helium cycles to a much fuller extent.

Of the fluids considered, the only others which also have high-temperature stability (nominally) are ammonia and cyanogen. The choice of sulfur dioxide over these is somewhat arbitrary, but it appears to be advantageous.

Sulfur dioxide is completely nonflammable. Although it will not make as low a volume plant as ammonia (TEAP of 5.75 for sulfur dioxide vs 1.49 for ammonia), the volume seems low enough for the application. Furthermore, the higher critical pressure of ammonia [11.280 MPa (1636 psi) abs compared to sulfur dioxide 7.881 MPa (1143 psi)] abs might require a pressure too high to contain easily in order to obtain a good thermodynamic fit. The higher critical temperature of sulfur dioxide was also thought to be advantageous for ease in obtaining a good fit.

In any case, sulfur dioxide serves to illustrate the potential value of a well-fitted, low-volume, high-temperature supercritical bottoming cycle.

7.4.5 Combined System Base Case Results

Figure 7.7 of Subsection 7.2 has illustrated the cycle schematic arrangement for Point C5, the combined closed-cycle base case. Selected thermodynamic cycle data for this arrangement are tabulated in connection with the appropriate temperature-entropy diagram on Figure 7.31. For this cycle, it has been calculated that a power plant of this

Curve 680328-A

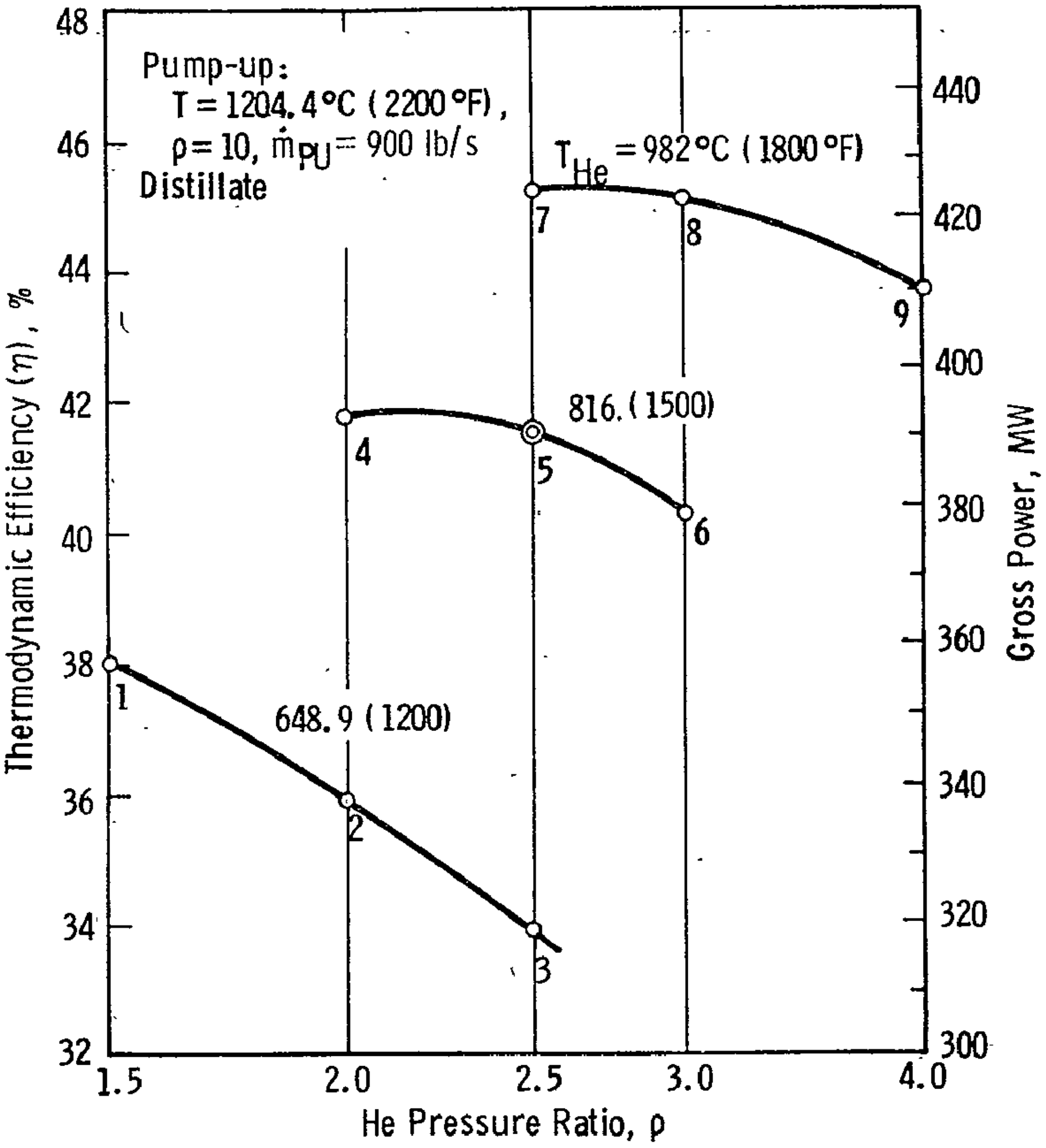


Fig. 7.32—Combined closed-cycle efficiency and power, ISO ambient

configuration would deliver approximately 380 MW at a net thermodynamic efficiency of nearly 41%.

7.4.6 Combined System Results of Parametric Variations*

The influence of helium temperature and pressure ratio on the engine performance is shown by Figure 7.32. It is evident that the helium temperature has a controlling effect. The performance progressively improves as temperature increases from 922 to 1089 to 1255°K (1200 to 1500 to 1800°F). This increase is associated with the higher efficiency of the helium cycle at the higher temperatures.

Note the double scale for efficiency and power in Figure 7.32. The efficiency and power are directly related as the cycle heat added is constant for all points on the curve. The heat added is fixed by the choice of pump-up cycle temperature and fuel, as the pump-up (combustion) airflow was always assumed to be 408 kg/s (900 lb/s). Thus, in Figure 7.32, the efficiency varies in lockstep with the power. (This is also true of Figures 7.33 and 7.36 through 7.42 which follow.)

Note also that the efficiency reported is, with respect to the engine electrical power, corrected for mechanical and generator loss, and the heat equivalent of the fuel based on the higher heating value. There is no account of the auxiliary power for providing the circulating water to the condenser and cooler in the results plotted in these figures.

The data are shown by the curves with regard to the pump-up and helium conditions, but without regard to the temperature and pressure of the steam in the bottoming cycle. This simplifies the curves and is justified, in that the steam conditions are generally set by the pump-up and helium conditions. Thus, the pump-up and helium parameters are regarded as independent variables, and the steam parameters as dependent variables.

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*The results listed in Table 7.5 and the figures shown below apply to thermodynamic efficiency and corresponding gross power output before related station auxiliary powers were deducted.

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Curve 682850-A

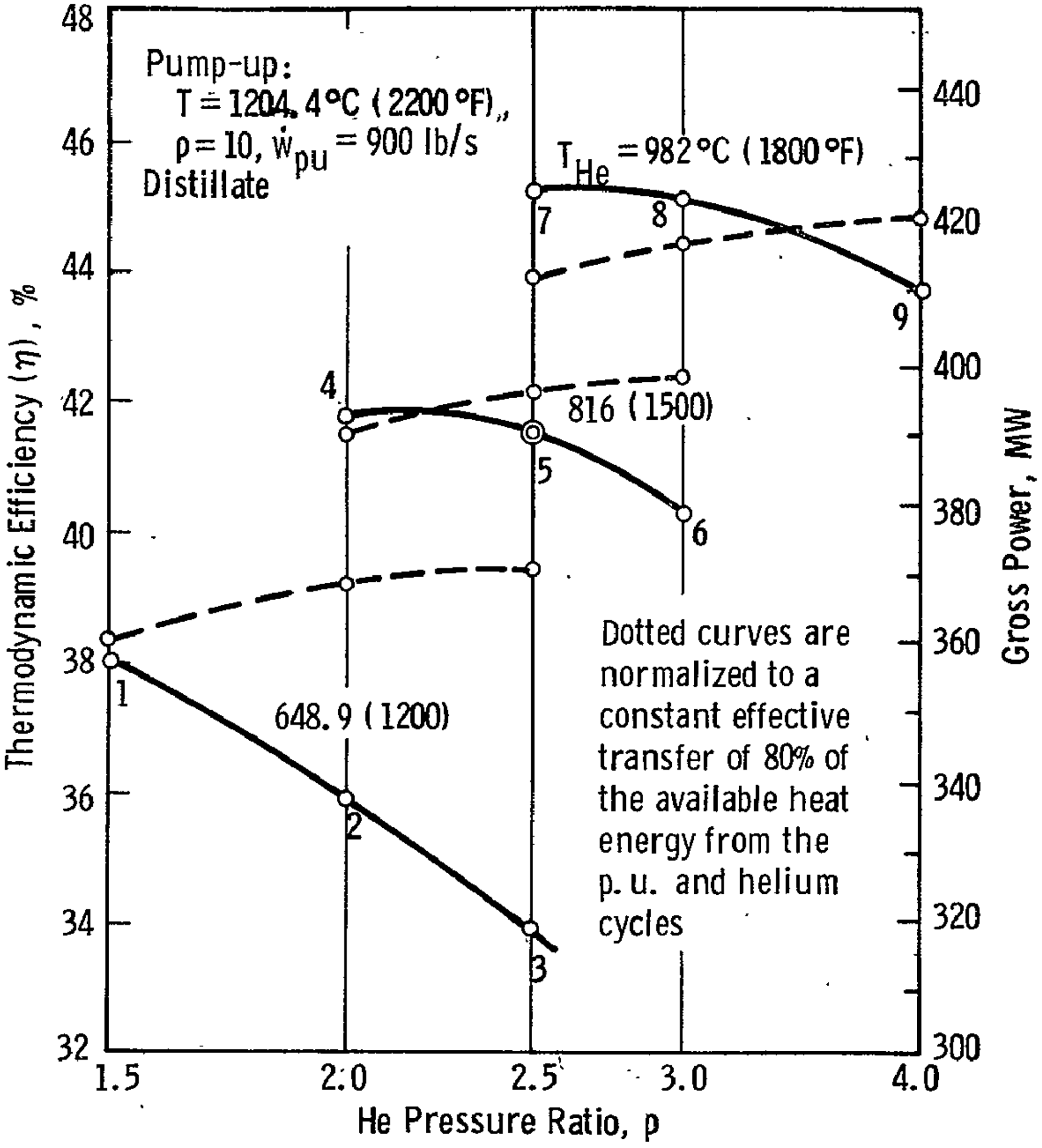


Fig. 7.33—Combined closed-cycle efficiency and power, ISO ambient

In the identification of the parametric points for calculation, it was intended that the steam cycle heat demands would be well fitted to the heat available from the pump-up and helium turbine exhaust streams. The degree of fit, however, has varied and is a noteworthy factor in the interpretation of the results. Table 7.6 lists the calculation points along with the effectiveness with which the thermodynamically available energy of the two exhaust streams is transmitted to the bottoming cycle. The values vary from 0.5787 to 0.8534. Also included in Table 7.6 are cycle efficiencies normalized for a constant available energy transmission effectiveness of 80%. These normalized values are plotted on Figure 7.33 and denoted by dashed lines. These curves are flatter than the directly calculated ones and show that much of the variation at a particular helium turbine temperature can be explained by the changing thermodynamic fit of the bottoming cycle.

Note that the base case, Point C5, is shown as a reference on all of the curves. This point is for a pump-up temperature and pressure ratio of 1478°K (2200°F) and 10 to 1, and a helium temperature and pressure ratio of 1089°K (1500°F) and 2.5 to 1. The use of distillate fuel is assumed.

The effect of pump-up temperature and pressure ratio is shown by Figure 7.34. The efficiency is notably lower at 1200°K (1700°F) than at 1478°K (2200°F). At 1200°K (1700°F) a greater portion of heat is absorbed by the helium, which gives an increase in power in the helium loop but cannot be transferred in full measure to the steam cycle due to the pinch-point limitation in the helium section of the vapor generator. Thus, a greater portion of the heat is rejected to the helium cooler to the detriment of the efficiency. On the other hand, the cycle heat added is roughly 9% larger at 1200°K (1700°F). [More heat is absorbed by the helium in reducing the furnace air to the lower temperature of 1200°K (1700°F); hence, more heat is added.] This tends to increase the power, but the increase is roughly offset by the drop-off in efficiency.

Table 7.6 – Effectiveness of Available Energy Transmission to Bottom Cycle

Calc. Point	$\varepsilon_{A.E.}$	$\eta_{\varepsilon = 0.8}$	Calc. Point	$\varepsilon_{A.E.}$	$\eta_{\varepsilon = 0.8}$
C1	0.7906	0.3828	C27	0.6859	0.4202
C2	0.6760	0.3915	C28	0.7886	0.4172
C3	0.5787	0.3936	C29	0.7954	0.4171
C4	0.8120	0.4147	C30	0.7886	0.4172
C5	0.7819	0.4201	C31	0.7954	0.4142
C6	0.7191	0.4232	C32	0.7828	0.4217
C7	0.8534	0.4380	C33	0.7862	0.4184
C8	0.8302	0.4433	C34	0.7903	0.4170
C9	0.7602	0.4473	C35	0.7799	0.4211
C10	0.6959	0.3328	C36	0.7847	0.4192
C11	0.6958	0.3578	C37	0.7819	0.4201
C12	0.7200	0.3709	C38	0.7819	0.4201
C13	0.7799	0.4183	C39	0.7732	0.4050
C14	0.7896	0.4210	C40	0.7440	0.4172
C15	0.8018	0.4208	C41	0.7056	0.4170
C16	0.8195	0.4194	C42	0.7069	0.4038
C17	0.7954	0.4119	C43	0.7075	0.3984
C18	0.8068	0.4092	C44	0.7777	0.4103
C19	0.8221	0.4057	C45	0.7837	0.4244
C20	0.8413	0.4014	C46	0.7058	0.4112
C21	0.7268	0.4150	C47	0.7047	0.3663
C22	0.7333	0.4149	C48	0.7448	0.4484
C23	0.7498	0.4201	C49	0.8198	0.4074
C24	0.7318	0.3998	C50	0.7180	0.4381
C25	0.7029	0.4043	C51	0.7448	0.4484
C26	0.7356	0.4202	C52	0.8539	0.4204

$\varepsilon_{A.E.}$ – Proportion of Available Energy of Pump-up and Helium Cycle Transmitted to Bottom Cycle.

$\eta_{\varepsilon = 0.8}$ – Power Plant Efficiency Normalized for $\varepsilon_{A.E.} = 0.8$.

Curve 680324-B

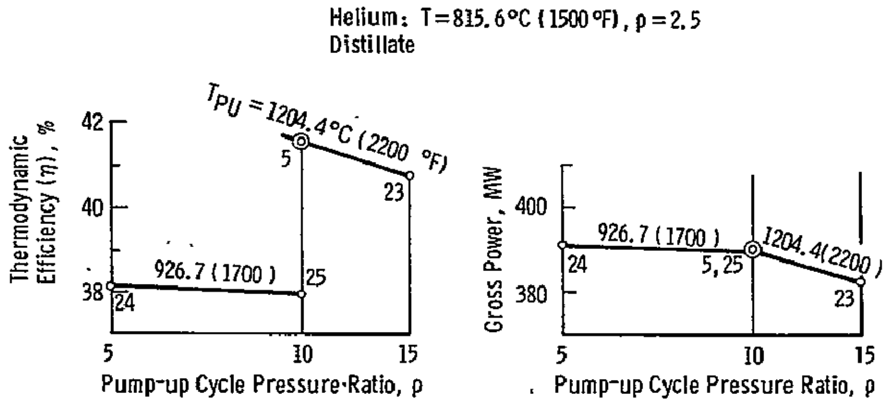
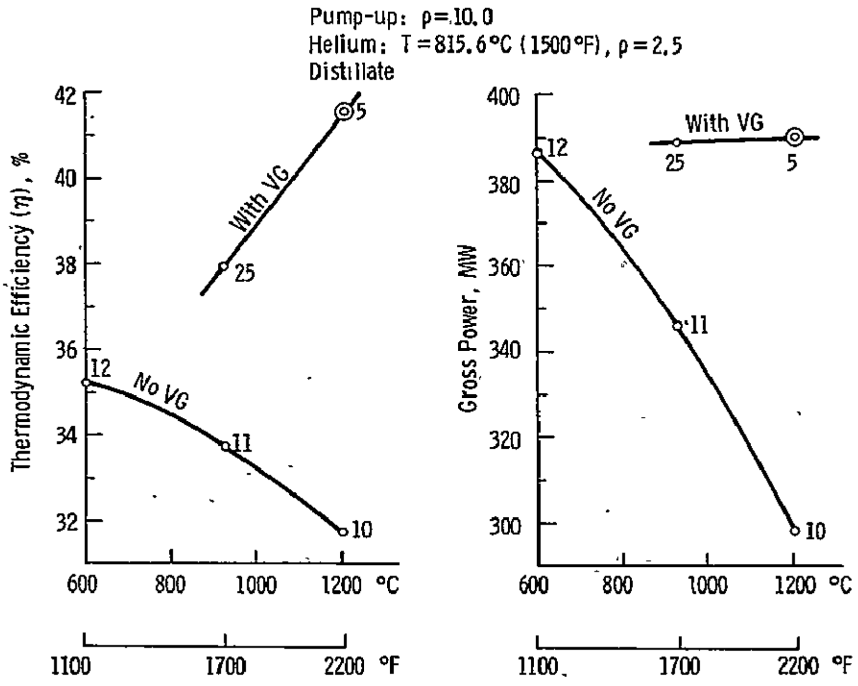


Fig. 7.34—Influence of pump-up temperature and pressure ratio



Influence of air/steam VG

Fig. 7.35 Combined closed-cycle efficiency and power, ISO ambient

Curve 680326-A

Pump-up: T = 1204.4°C (2211°F), ρ = 10.0
Helium: T = 815.6 °C (1500°F), ρ = 2.5
Distillate

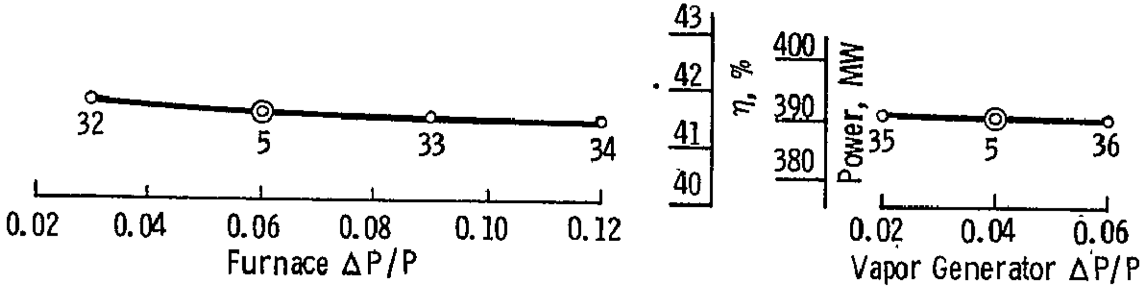


Fig. 7.36 – Influence of pressure loss in pump-up circuit

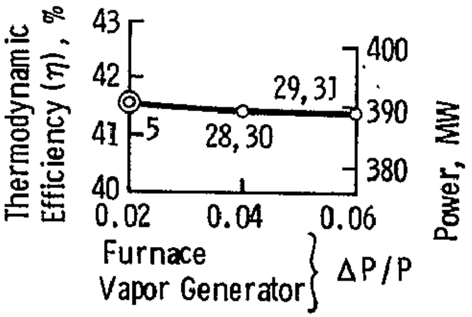


Fig. 7.37 – Influence of pressure loss in helium circuit

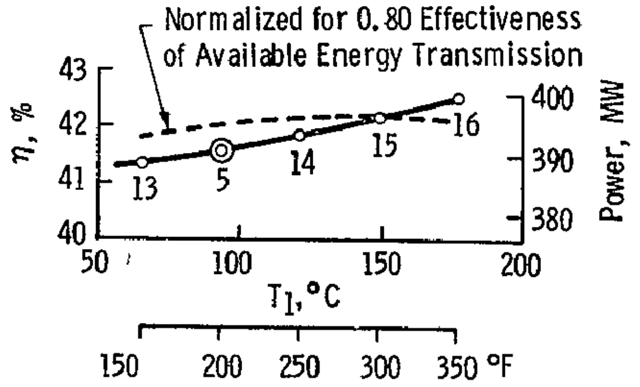


Fig. 7.38 – Influence of helium temperature at VG exit (compressor inlet)

Combined closed cycle efficiency and power, ISO ambient

The effect of including an air-to-steam vapor generator is shown in Figure 7.35. Without the vapor generator, a greater portion of the heat from the pump-up turbine is rejected in the exhaust, particularly for the case with the pump-up turbine inlet temperature of 1478°K (2200°F).

Figures 7.36 and 7.37 show the effect of pressure loss in the pump-up and the helium circuits, respectively. The individual effect of furnace loss and vapor generator loss is the same with respect to each circuit.

Figure 7.38 shows the effect of the helium temperature at the vapor generator exit; i.e., at the compressor inlet. The performance improves with increased compressor inlet temperature. This effect is opposite to that commonly associated with compressor inlet temperature. However, it must be noted that the thermodynamic heat rejection temperature from the overall closed-combined cycle is linked most directly to the temperatures at the pump-up compressor inlet, the pump-up stack and the supposed condenser; not to that of the helium compressor inlet.

As the helium compressor inlet temperature increases, its outlet temperature also increases; and it accepts heat from the pump-up set in a more efficient temperature range. This is partially counterbalanced by the greater power required to drive the helium compressor. The effectiveness of transmission of available energy to the bottom cycle is also improved. This last effect has been removed for the dotted line of Figure 7.38 showing the efficiency values normalized for an 80% effectiveness of available energy transmission. These show an optimum compressor inlet temperature of about 394°K (250°F).

The pinch point is shown by Figure 7.39 to have a notable effect on the performance. As the vapor generator pinch point temperature difference increases from 22.2 to 44.4°K (40 to 80°K), less of the heat absorbed by the helium is transferred to the steam. This is shown by the increase in helium temperature at the vapor generator exit (T5 in Table 7.5) and by the increase in heat rejected from the helium cooler.

Figure 7.40 shows the effect of condenser pressure associated with the temperature of the circulating water. The relation between the condenser pressure, saturation temperature, and water temperature is shown in Table 7.7. The 11.85 and 30.48 kPa (3.5 and 9 in Hg) abs

Curve 680323-B

Pump-up: 1204.4°C (2200°F), p=10.0
Helium: 815.6°C (1500°F), p=2.5

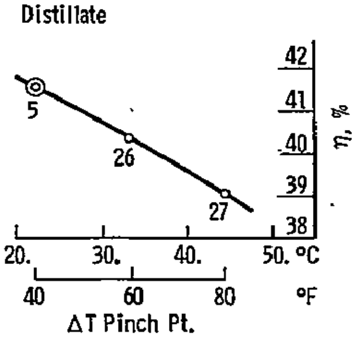


Fig. 7.39—Influence of pinch point

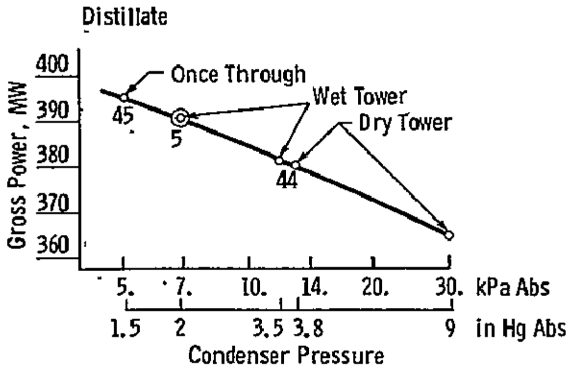


Fig. 7.40— Influence of condenser pressure

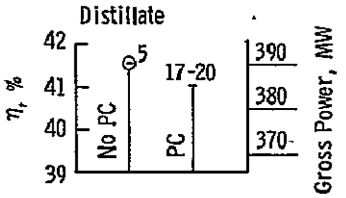


Fig. 7.41—Influence of precooler

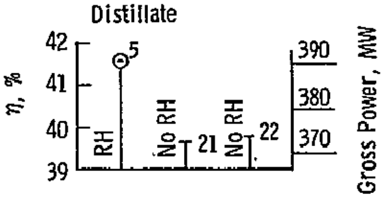
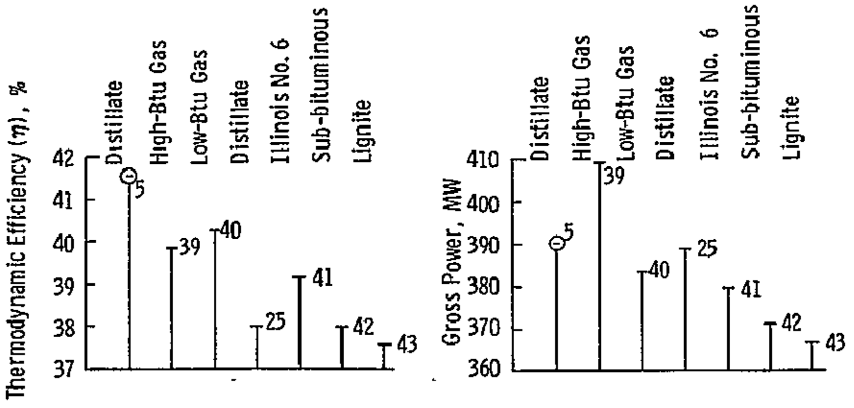


Fig. 7.42—Influence of reheat



Influence of fuels

Points 25, 41, 42, 43; 926.7°C (1700°F) Pump-up Temperature
Points 5, 39, 40; 1204.4°C (2200°F) Pump-up Temperature

Fig. 7.43—Combined closed-cycle efficiency and power, ISO ambient

Table 7.7 - Heat Rejection Conditions

Pressure, in Hg abs	Saturation Temperature, °F	Cooling Water, °F	Cooling Mode	Ambient
1.5	91.7	49.0	Once through	ISO
2.0	101.1	66.5	Wet tower	ISO
3.5	120.6	--	Wet tower	5% day
3.8	123.4	90.0	Dry tower	ISO
9.0	157.1	--	Dry tower	5% day

conditions are not study points, but are included in the performance summary (Table 7.5).

The effect of the precooler is shown by Figure 7.41. Note that the precooler reduces the helium temperature to 309°K (96.5°F) at the inlet of the compressor. [This is in line with the 16.7°K (30°F) approach temperature in the precooler.] As such, Points C17 through C20 are best regarded in association with Figure 7.38. It is a matter of semantics whether the temperature is reduced to 309°K (96.5°F) in the cooler and precooler or in the cooler alone. (Had it been determined that the cooler was necessary when the study was planned, the precooler points would not have been included.) We felt that the helium temperature could be reduced to its final value in the vapor generator, but for most points this is impossible without violating the 22.2°K (40°F) pinch point temperature difference.

Figure 7.42 shows that the use of a nonreheat bottoming cycle results in about a two-point drop in efficiency and a corresponding decrease in power. Without reheat, the available heat from the pump-up set in particular is not fully utilized in the steam loop. Note that the amount of the decrement is for this particular cycle.

The influence of fuels is shown by Figure 7.43. Due to the difference in pump-up temperature, fuels for each temperature must be compared as a group. In each group, the comparison is with respect to distillate. Of the coal points at 1200°K (1700°F) temperature, Illinois No. 6 gives higher efficiency and less power than does distillate. With distillate, the heat added is 6% higher. (This is associated with the constant airflow and the combustion properties of the fuel.) This increases the power, but the increase is somewhat offset by the drop-off in efficiency. In particular, the additional heat is absorbed by the helium cycle, giving some increase in power; but it cannot be passed on in full measure to the steam cycle because of the limitation imposed by the pinch point. Were it not for this limitation, the efficiency would remain near constant and the power would increase in proportion to the heat added (as in the recuperated cycle). Comparing the coal points, there is an approximate two-point drop-off in efficiency in going from Illinois No. 6 to subbituminous to lignite. This decrement, in the case of the low-Btu coals, is due to the greater percentage of work in the low-efficiency pump-up set. There is a corresponding decrease in power as the heat added is roughly constant. Turning now to the gas points at 1478°K (2200°F) pump-up cycle inlet temperature, the efficiency is approximately 1-1/2 points less with both high- and low-Btu gas than with distillate. This drop-off is related to the greater difference in the higher and lower heating value of the gaseous fuels as compared with the liquid fuel. Note that the performance of the low-Btu gas point allows for the energy requirements of the coal gasification plant.

7.4.7 Combined Systems with Organic Fluid Bottoming Cycles

Special attention was given to the use of organic fluids in the bottoming cycles. A detailed description of the results of those calculations, Points C46 through C52, is given below.

Points C46, C47, and C52 illustrate the importance of bottoming fluid top temperature capability and of the value of good thermodynamic fit between the subposed cycle heat absorption line and topping cycle heat rejection line. These parametric points and Point C5 are similar in that each is used under high-temperature primary cycles [pump-up cycle turbine inlet temperature of 1478°K (2200°F) and helium cycle turbine inlet temperature of 1089°K (1500°F)]. A tabulation of the efficiency results of these cycles is given in Table 7.8.

As with other cycles, much of the efficiency difference here can be explained by the difference in the available energy transmission effectiveness. Although the normalized cycle efficiencies at the 0.8 available energy transmission effectiveness are tabulated, the physical implications of achieving such values must be considered. For the steam case (Point C5), the higher transmission effectiveness was obtained for a physically plausible cycle. To maintain such a level with other steam bottomed cycles, however, would require similar high values of helium

Table 7.8 - Organic Bottomed Closed Combined-Cycle Efficiency Comparison

Point No.	Power, MW	Thermodynamic, %	Available Energy Transmission Effectiveness, B	Cycle Efficiency with Available Energy Transmission Effectiveness Corrected to 0.8
C5	390.2	0.415	0.782	0.420
C46	364.2	0.388	0.706	0.411
C47	326.8	0.348	0.705	0.366
C52	408.2	0.435	0.854	0.420

turbine exhaust temperature and high helium compressor inlet temperature. Increasing the cycle complexity would not materially improve the level of available energy transmission effectiveness. The lower cycle efficiency values of the R-12 points (Points C46 and C47) illustrate a fundamental point: that fluids cannot accept the available energy effectively where fluid top temperatures are limited by the chemical instability of the fluid. The 644°K (700°F) limit is for practical purposes about as high as R-12 could be used. Point C47 does not utilize recuperative feed heating and further illustrates the losses encountered when the superheated exhaust energy of these fluids is directly rejected to the heat sink. Cycle temperature-entropy diagrams for Points C46 and C47 are given as Figures 7.44 and 7.45.

The temperature-entropy diagram for Point C52 is given in Figure 7.46. Since sulfur dioxide is stable to high temperatures, the bottom cycle has been intentionally closely fitted to the available heat supply, the sulfur dioxide turbine inlet temperature being 811°K (1000°F). The close thermodynamic fit is reflected in the available energy transmission effectiveness of 0.854 and the cycle efficiency of 0.435 - two percentage points above that of Point C5. The sulfur dioxide turbine exhaust superheat has been used recuperatively to aid in feed heating the sulfur dioxide liquid rather than rejecting it to the heat sink. The good thermodynamic fit is made possible by using this exhaust superheat and by having the top pressure so far above the critical pressure. At 17.327 MPa (2500 psi) abs, sulfur dioxide has a reduced pressure of 2.19, a value which would correspond to a pressure of 48.263 MPa (7000 psi) abs in steam.

Since sulfur dioxide is a low-boiling fluid, this cycle also avoids the excessively large exhaust annulus-area turbines required when steam is used.

Cycle Points C48 through C51 use methylamine as the working fluid of the bottoming cycle below the recuperated closed-cycle helium turbines. The methylamine cycles are supercritical cycles designed to

Curve 682029-A

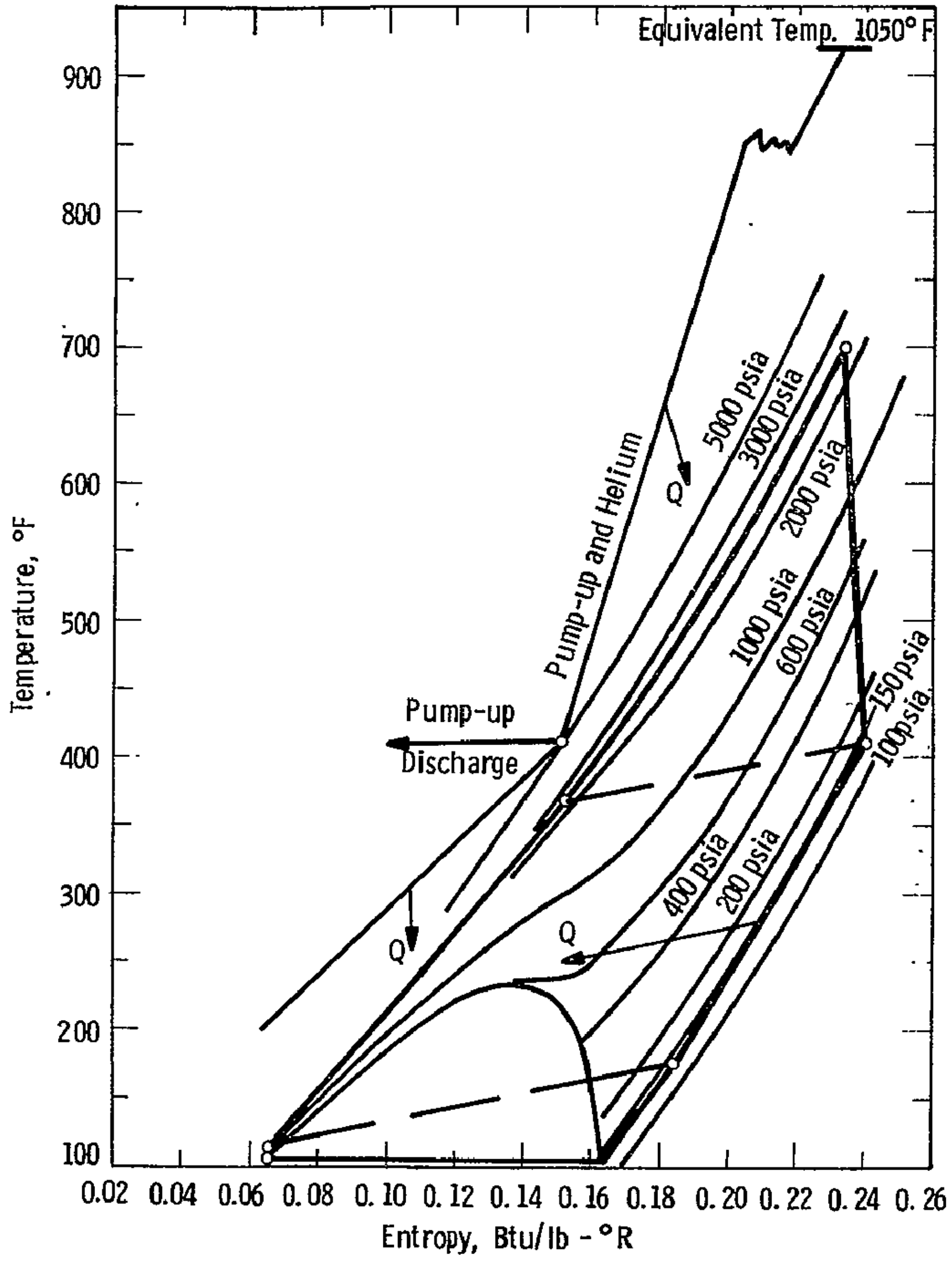


Fig. 7.44 —Dichlorodifluoromethane (R-12) T-S diagram. (Closed combined cycle Point 46)

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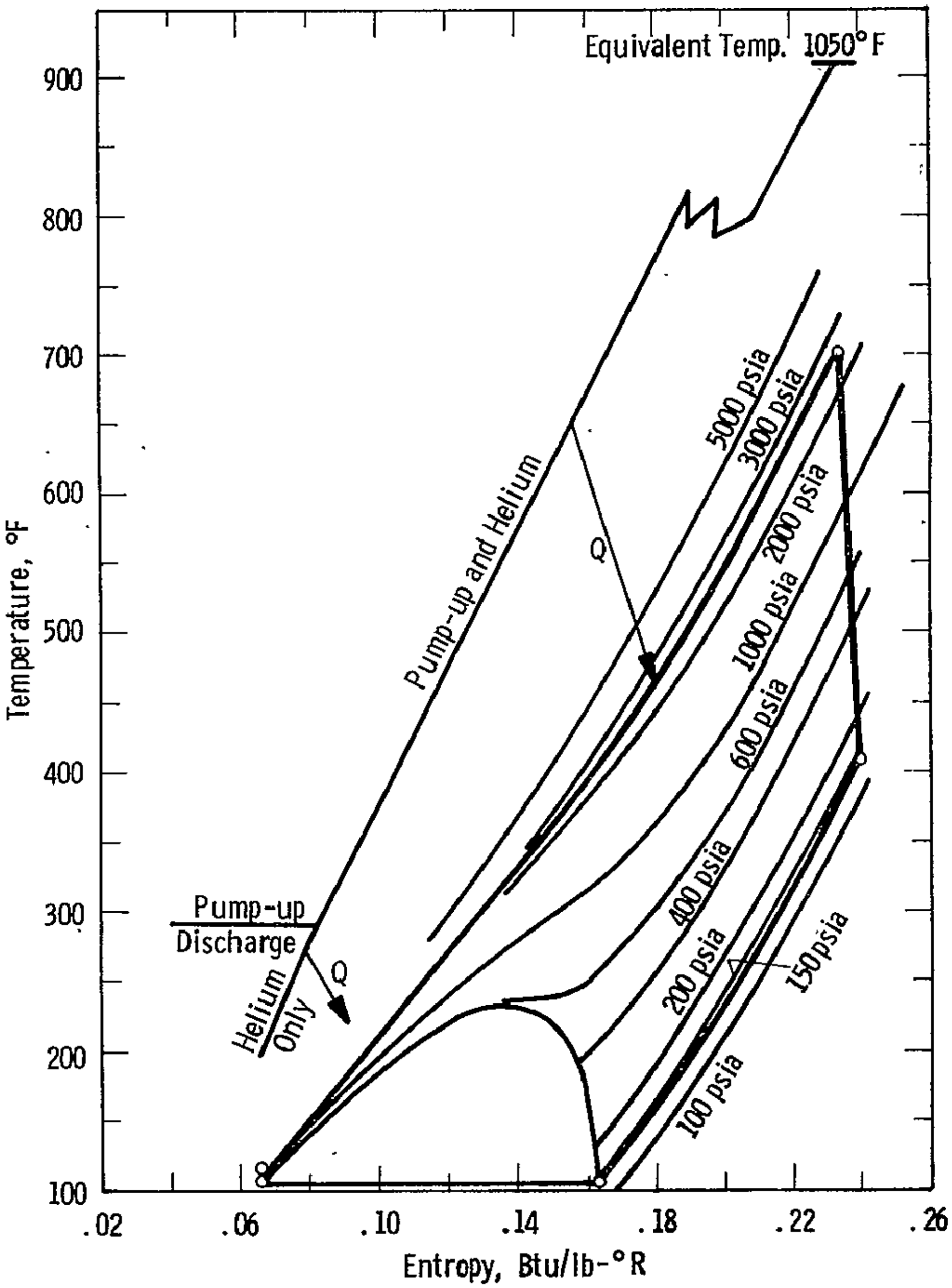

Fig. 7.45 —Dichlorodifluoromethane (R-12) T-S diagram. (Closed combined cycle Point 47)

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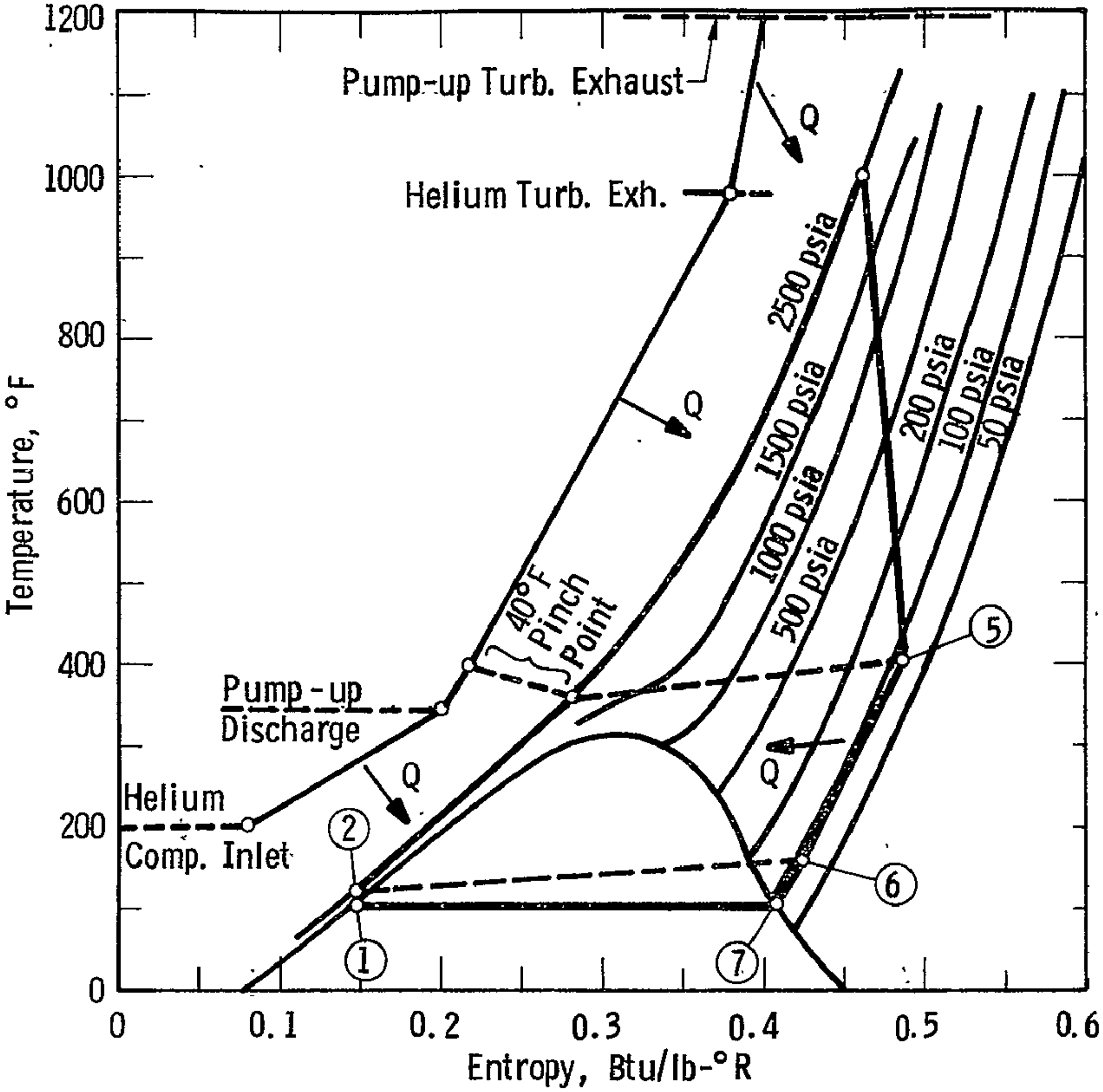

Fig. 7.46 —Sulfur dioxide T-S diagram. (Closed combined cycle Point 52)

REPRODUCIBILITY OF THE ORIGINAL PAGE IS POOR have the turbine expansion line end close to the saturation line, thus avoiding the superheated exhaust energy usage problem. The relatively low temperatures of the pump-up and helium heating streams permit the close thermodynamic fits for these cycles. Figure 7.47 depicts the temperature-entropy diagrams for these methylamine cycles. The results of thermodynamic efficiency calculations of these and other related cycles are tabulated below.

Table 7.9 - Methylamine Working Fluid Bottoming Cycle Comparison

Point No.	Power, MW	Power Plant Efficiency, %
R6	328.5	0.350
R32	371.1	0.338
C48	413.4	0.440
C49	449.7	0.410
C50	400.0	0.426
C51	413.4	0.440

Points C48, C50, and C51 utilize organic fluid bottoming cycles subposed below recuperated closed-cycle R6, and C49 incorporates a subposed cycle below R32. Cycle C48 has as high an efficiency (0.44) as any of the closed combined cycles for the same pump-up and helium cycle turbine inlet temperatures [1478 and 1089°K (2200 and 1500°F), respectively]. The efficiency difference between Cycles C48 and C49 (0.03) denotes the difference resulting from a 1478°K (2200°F) pump-up turbine inlet temperature and one of 1089°K (1500°F).

Cycle C50 is similar to C48 except that heat is rejected to water from a dry cooling tower. Its performance is poorer, as would be

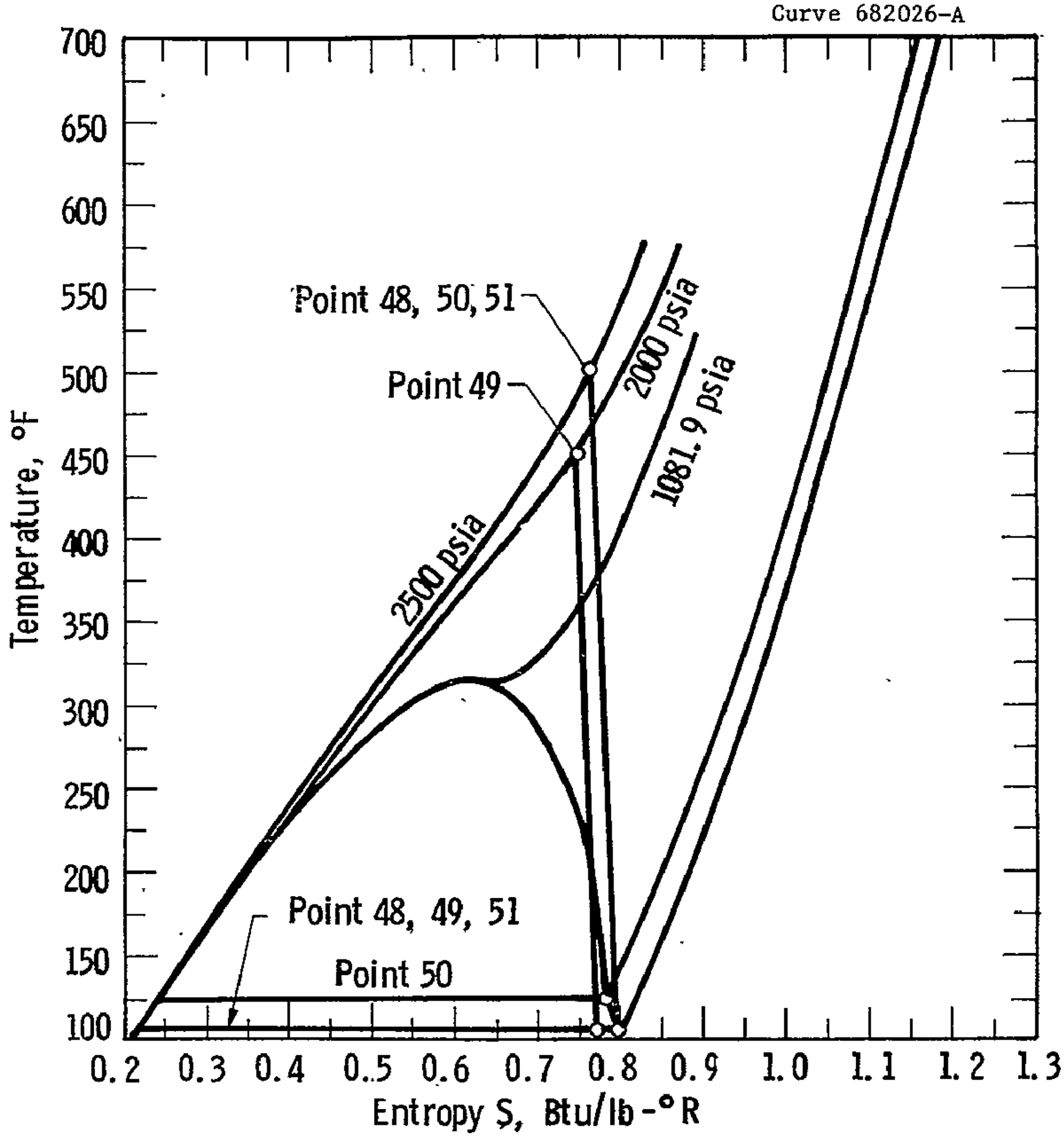

Fig. 7.47 —Methylamine T-S diagram. (Closed combined cycles Points 48, 49, 50, and 51)

expected. Cycle C50 is intended for comparison with C51, since it also has a dry cooling tower, but with direct condensing. Since the intermediate water loop is avoided, Cycle C51 is thermodynamically the same as C48. Thus, C51 shows a thermodynamic performance with a dry tower equal to that of C48 with a wet tower. This efficiency gain is one advantage of using a low-boiling fluid having a volumetric flow sufficiently low that the fluid can be deployed directly to an air-cooled condenser.

7.5 Capital and Installation Costs of Plant Components

7.5.1 Description of the Base Case Power Plants

Three base cases have been selected for study in the closed-cycle gas turbine concept category. Two base cases have been identified among the recuperated closed cycles, and one base case has been selected for study within the combined closed-cycle group. Capital and installation costs were generated first for the base cases, and later for the remaining parametric points.

Base Case A of the recuperated closed-cycle systems corresponds to Point R25. It utilizes a single pump-up gas turbine to pressurize a fluid bed furnace firing Illinois No. 6 coal. The combustion gas turbine compressor airflow has been set at 408 kg/s (900 lb/s) with a compressor pressure ratio of 10 to 1 and turbine inlet temperature of 1200°K (1700°F). The closed-cycle helium gas turbine utilizes a compressor pressure ratio of 2.5 to 1 and has a turbine inlet temperature set at 1089°K (1500°F). The helium cycle recovers waste heat by means of a recuperator having an effectiveness of 0.9. Heat rejection below the helium cycle recuperator is accomplished by means of a wet cooling tower. No exhaust heat recuperation is used with the pump-up turbine cycle.

The Base Case A power plant island arrangement is illustrated by Figure 7.48, and the overall site plot plan is shown in Figure 7.49. A cross-sectional view of the pressuring or pump-up gas turbine is given in Figure 7.50. This unit incorporates a single-shaft rotor arrangement

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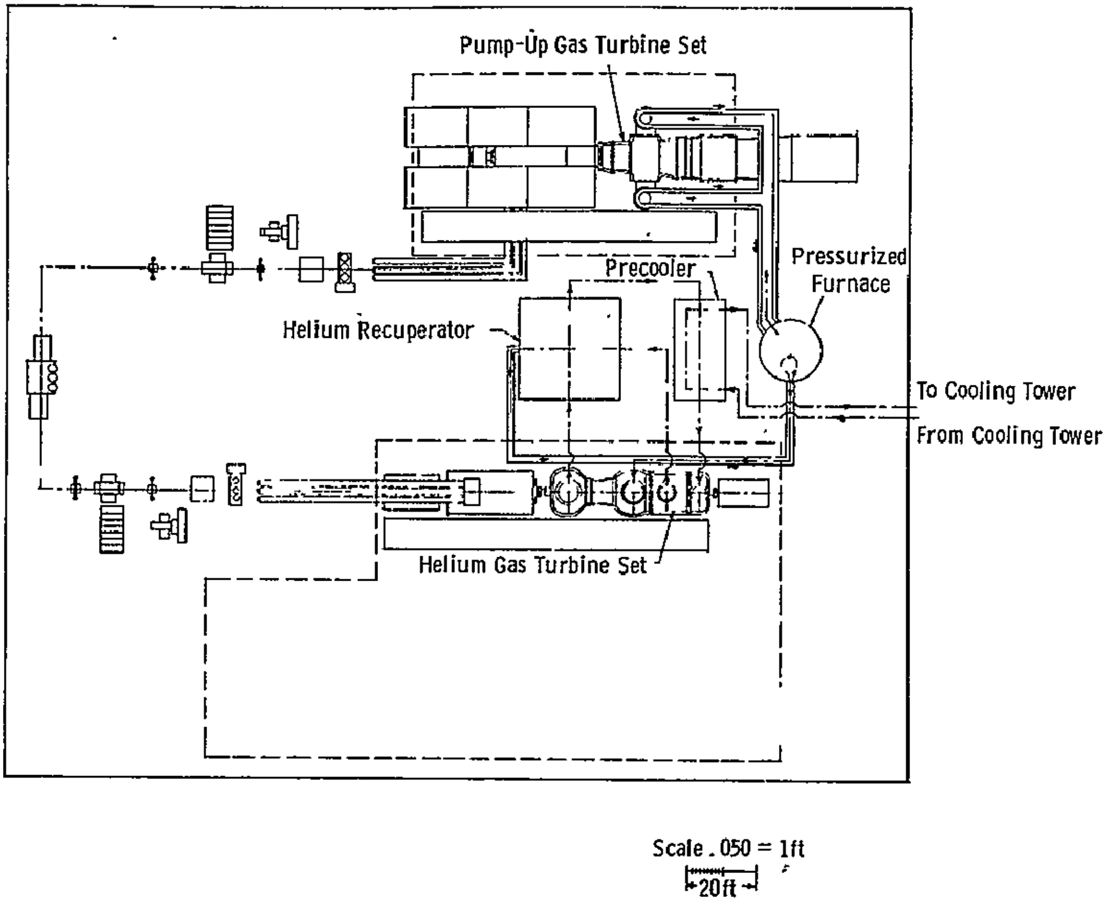


Fig. 7.48—Plant island arrangement recuperated closed-cycle gas turbine (Base Case A)

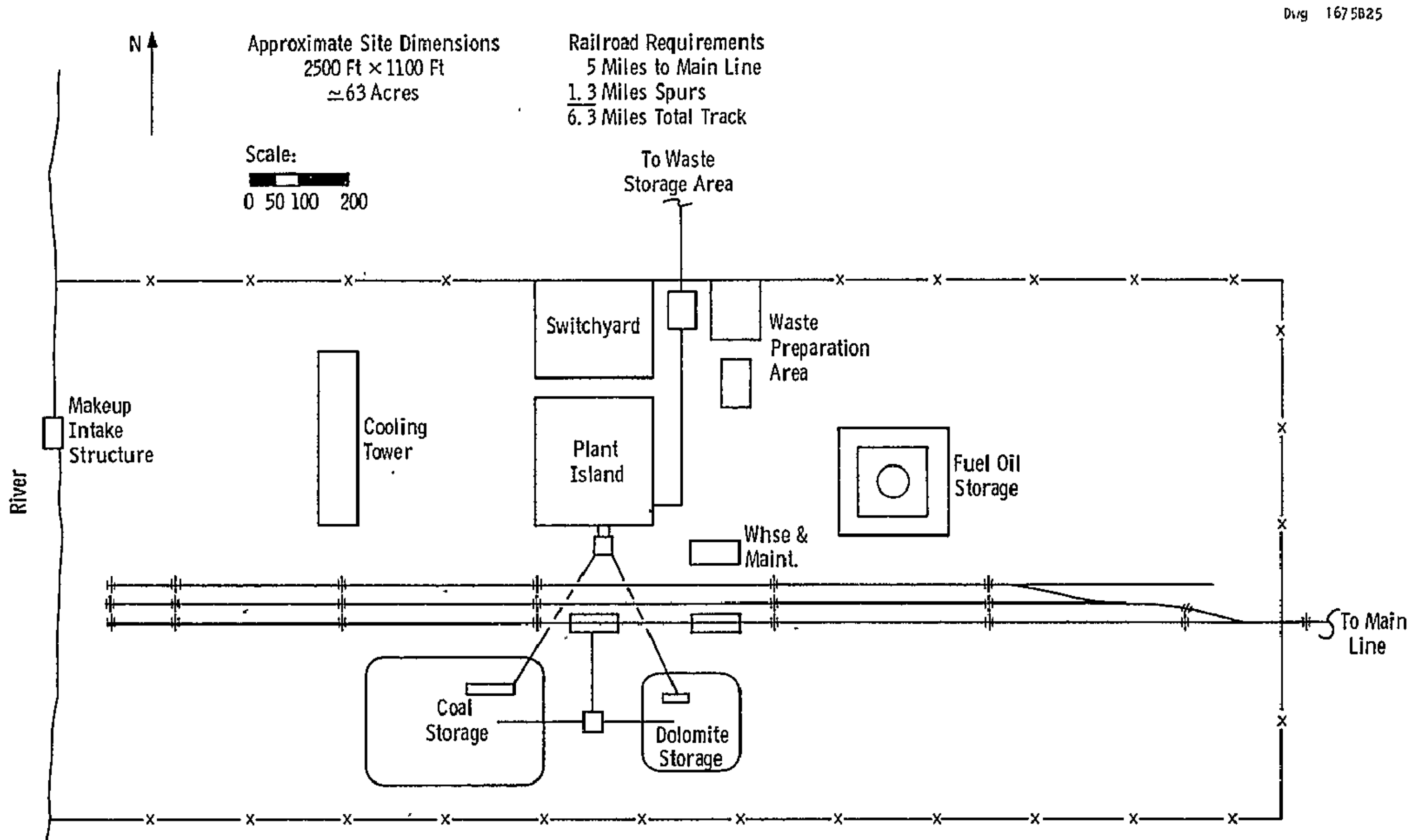


Fig. 7.49— Closed cycle gas turbine Base Case 2

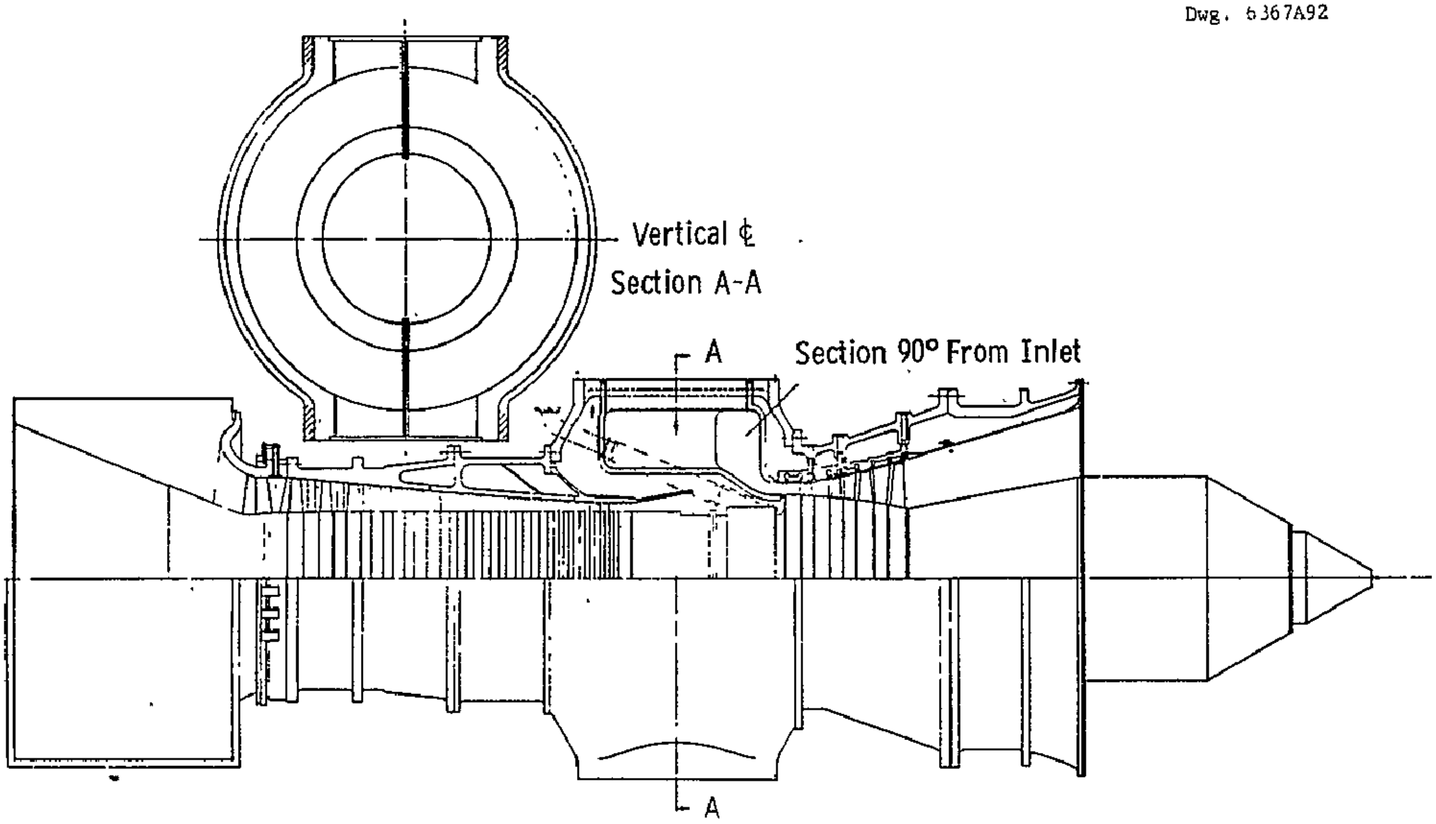


Fig. 7.50—Furnace pressurizing (pump-up) gas turbine engine

similar to the designs described in the recuperated open-cycle gas turbine and combined gas-steam turbine portions of the study. The combustion section of this unit is highly modified, however, compared to the other units. All compressor discharge air is withdrawn from the gas turbine cylinder through two large ports. The air is directed to the pressurized furnace; and combustion products are returned by means of a concentric piping arrangement, with hot combustion gases returning via the interior pipe and cooler compressor discharge air passing through the outer annulus. A convection impingement air-cooling approach has been selected for the turbine blade cooling system as appropriate for operation at turbine inlet temperatures of 1478°K (2200°F).

Figure 7.51 illustrates the closed-cycle helium gas turbine utilized in Base Case A. This unit features a 60 rps (3600 rpm) power turbine and a separate 71.3 rps (4280 rpm) high-pressure shaft. The turbine sections of each shaft utilize conventional construction through bolted individual disk designs. A welded assembly of individually forged disks has been selected for the compressor rotor design. Each shaft is supported by a two-bearing arrangement with tilting-pad fluid film journal and tilting-pad thrust bearings. Special sealing circuits are required to prevent oil contamination of the main working fluid.

Several niobium- and molybdenum-based blading alloys have been considered for use in the initial high-pressure turbine stages for uncooled operation at the 1255°K (1800°F) turbine inlet temperature. Metallurgical studies have indicated that although the niobium alloys have superior rupture strength, they appear to suffer serious deterioration in impure helium. The most promising candidate alloy identified is the commercial molybdenum-based alloy TZM.

The overall power plant arrangement of Base Case A, exclusive of waste storage area, encompasses 254,952 m^2 (63 acres). Fuel and dolomite delivery is by unit train with four 29-car unit trains of coal and two 31-car unit trains of dolomite per week. There is an auxiliary distillate fuel storage tank which is used during start-up and stand-by

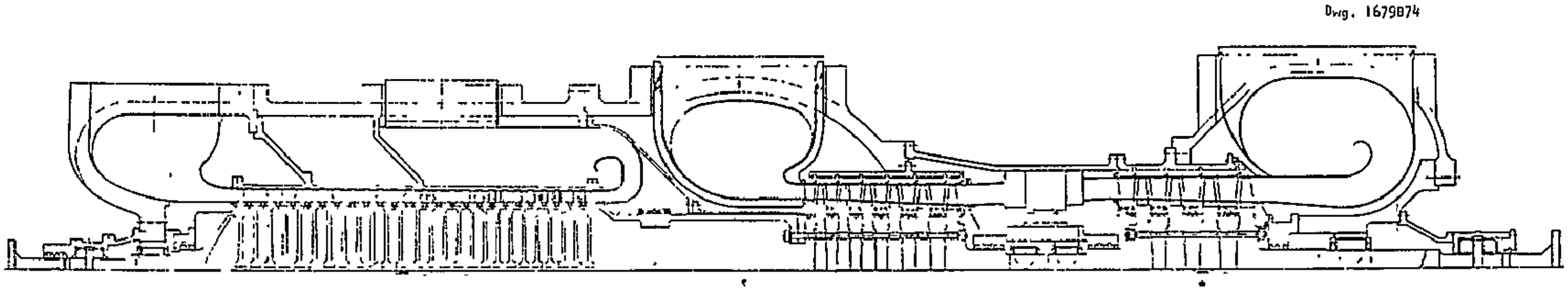


Fig. 7.51 —Recuperated cycle helium gas turbine engine (Base Case A)

operation. The waste dolomite storage area totals 728,453 m^2 (180 acres). Heat injection from the plant is accomplished by one eight-cell wet cooling tower.

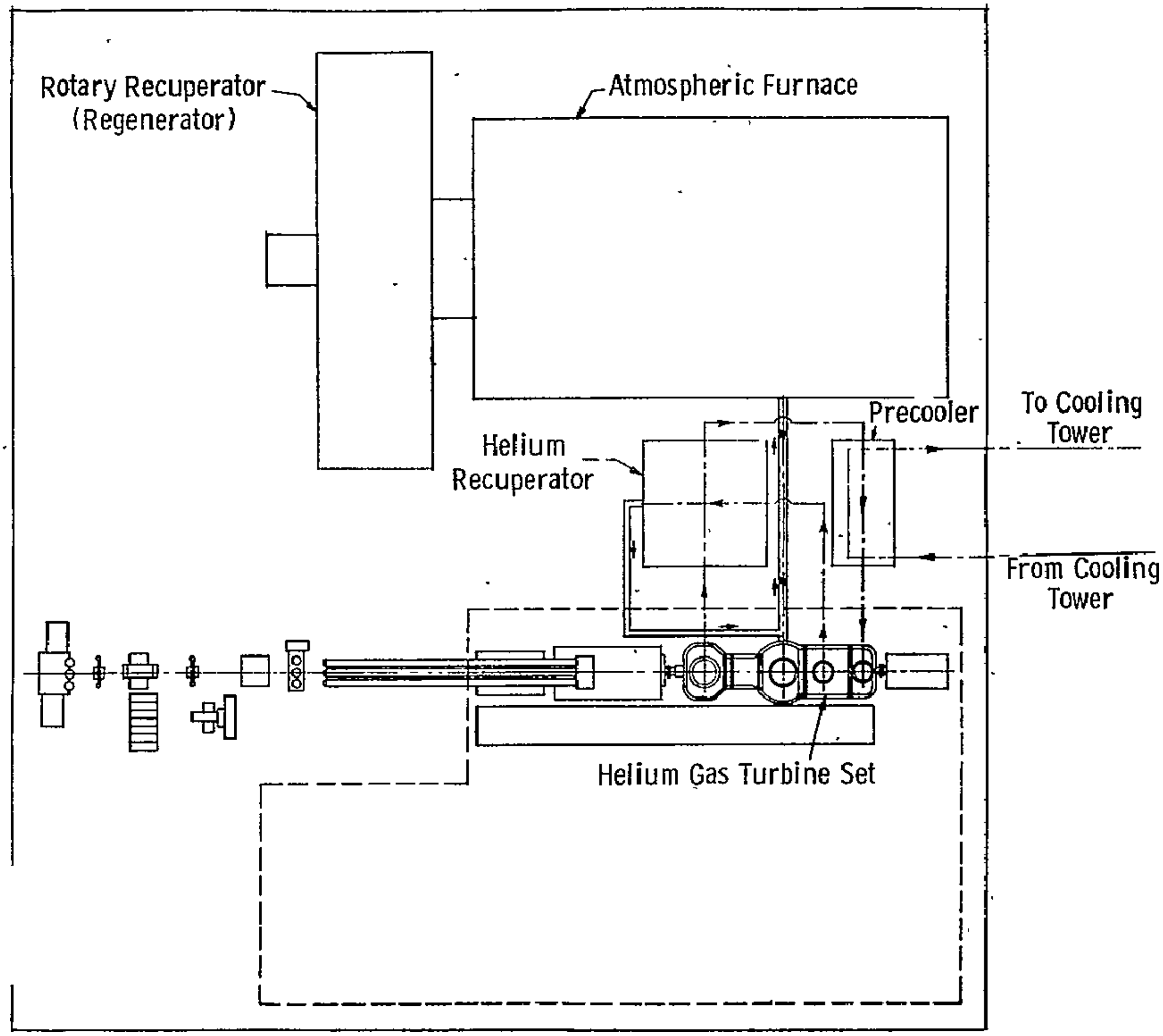
The recuperated closed-cycle system Base Case B corresponds to Point R48. The turbine island arrangement for this plant is shown in Figure 7.52, and the overall plot plan arrangement is illustrated in Figure 7.53. This plant utilizes a single closed-cycle helium turbine which receives its heat input from an atmospheric pressure furnace (in contrast with the pressurized furnace of Base Case A). Consequently, no pressurizing or pump-up combustion gas turbine is required. The power plant is fired on coal-derived distillate fuel. The closed-cycle helium gas turbine is essentially similar in design to the unit of the Base Case A power plant. The power plant site arrangement is similar also to the Base Case A arrangement, with the principal differences being the substitution of liquid fuel storage tanks for the coal and dolomite piles and the elimination of the waste dolomite storage area.

One base case has been identified from the grouping of combined closed-cycle systems under study. This base case corresponds to Point C5. The base cycle consists of a power-producing pressurized furnace subsystem, which is bottomed by a closed-cycle gas turbine system. Both these Brayton cycles are, in turn, bottomed by a conventional steam Rankine cycle. The plant island arrangement for the base case is illustrated in Figure 7.54; the overall power plant plot plan in Figure 7.55.

A single pump-up gas turbine is incorporated in the combined closed-cycle base case. The electrical output from this 408 kg/s (900 lb/s) inlet airflow machine is 113 MW. The unit has a turbine inlet temperature of 1478°K (2200°F) and a compressor pressure ratio of 10 to

The single helium closed-cycle gas turbine selected for this plant is illustrated in Figure 7.56. It is similar in design to the unit of Base Case A, with the essential difference being the construction of the compressor rotor. This design incorporates a through-bolted assembly

Dwg. 6368A09



Scale .050 = 1ft

20 ft

Fig. 7.52—Plant island arrangement recuperated closed-cycle gas turbine (Base Case B)

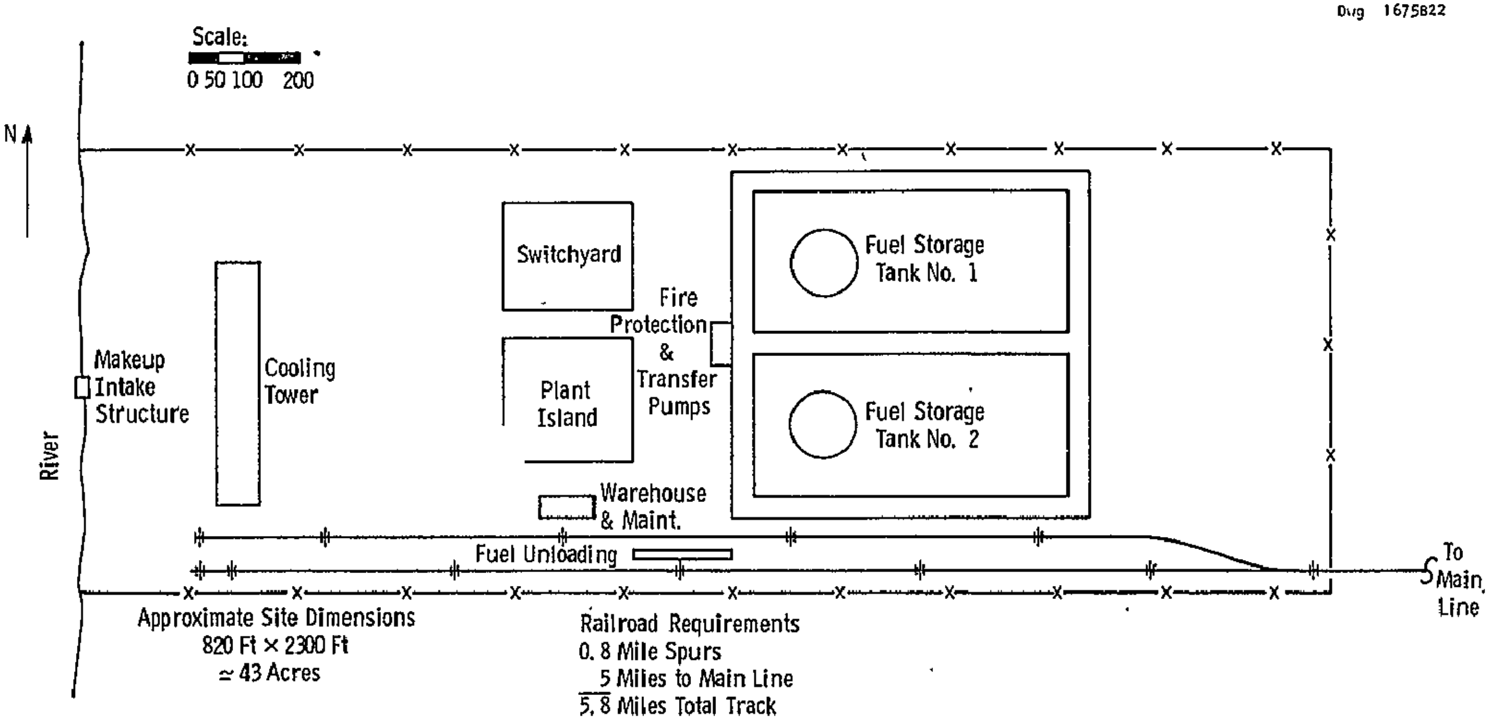
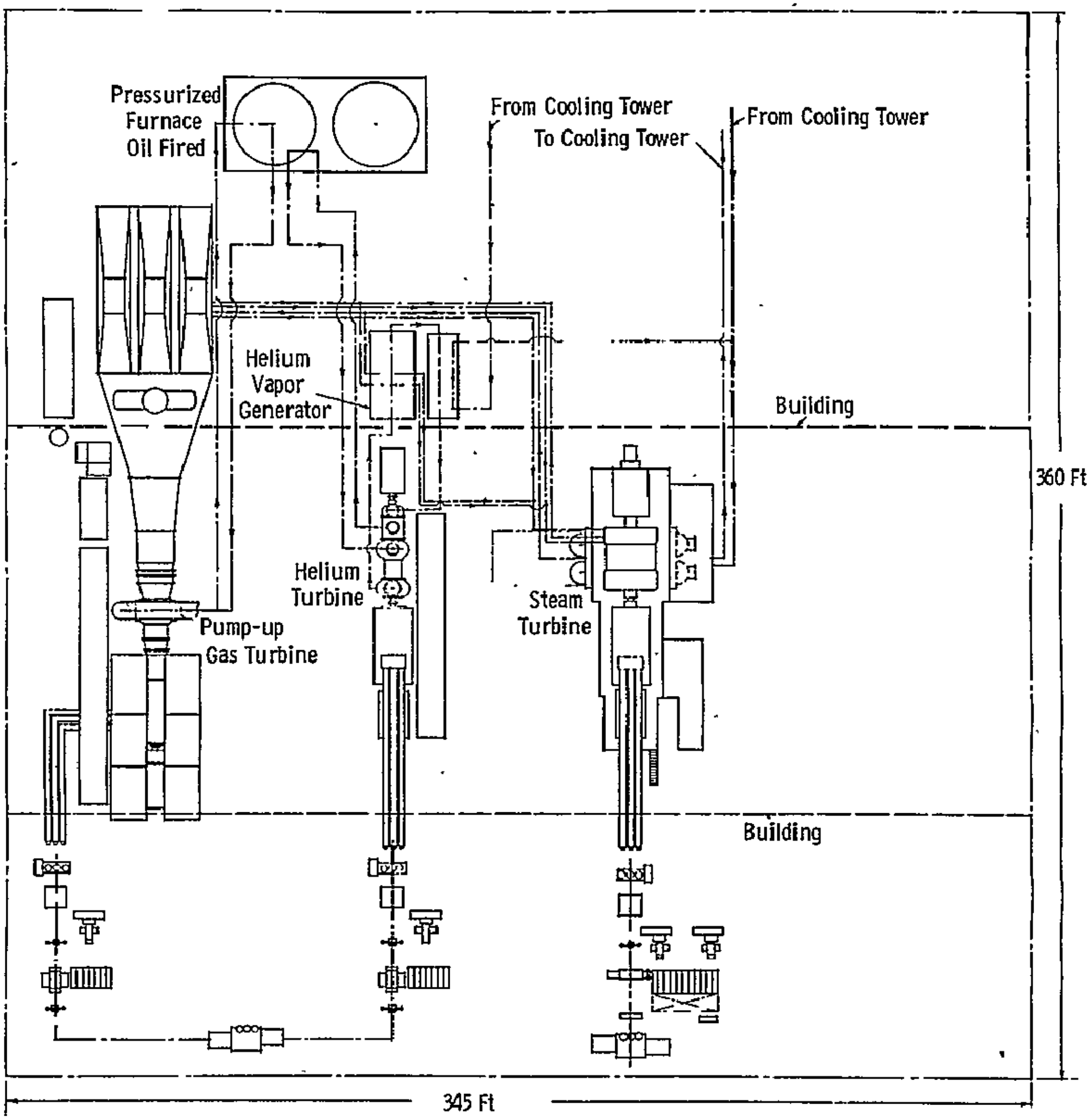


Fig. 7.53— Recuperated closed-cycle Base Case 3

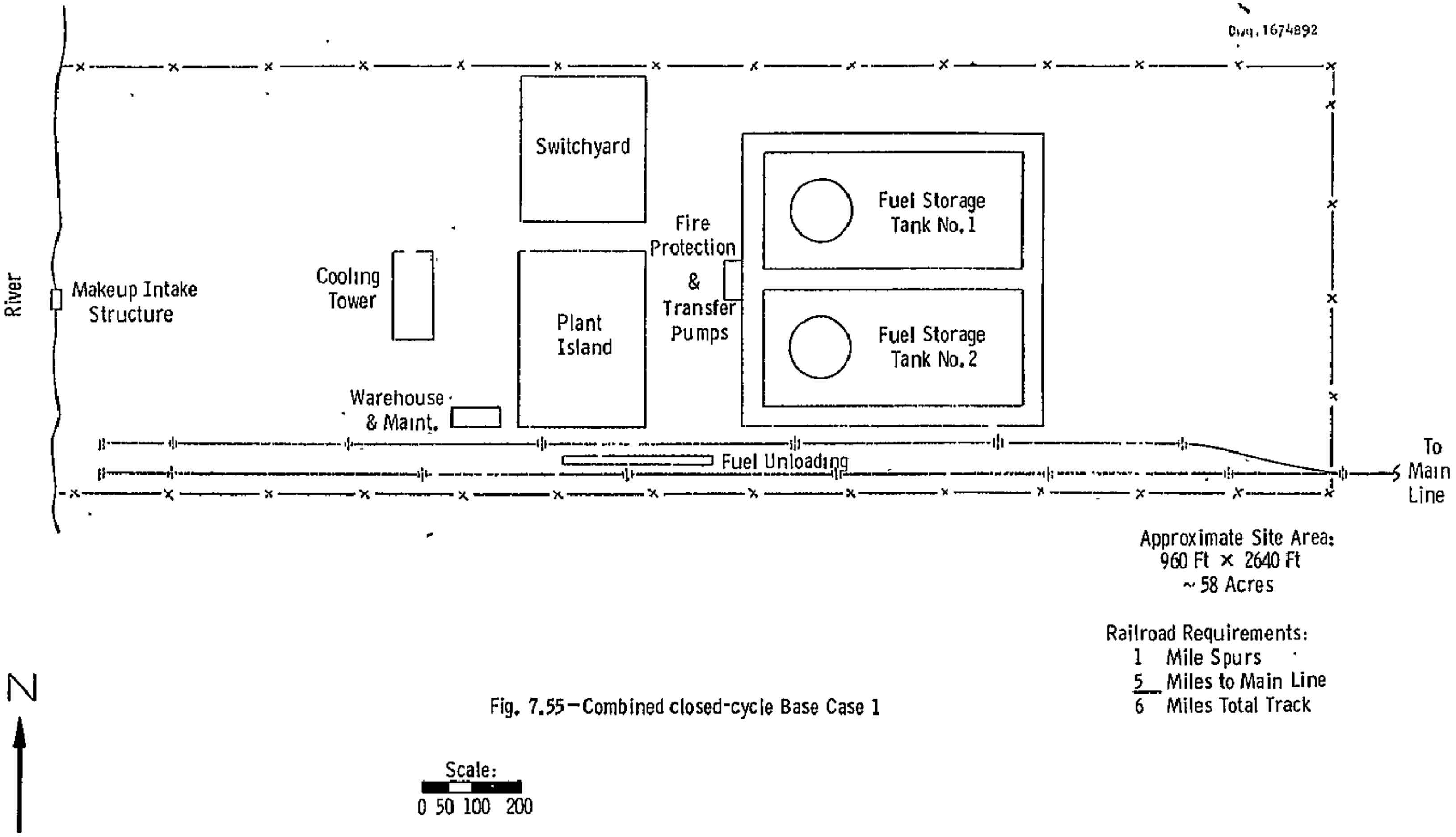
Dwg. 1679380



Sub 1– Changed Gas Turbine Steam Boiler
From 2 to 3 Modules.
Removed Cooling Towers From Island
R. G. Glenn 4/18/75

Scale .050 = 1 Ft
20 ft

Fig. 7.54– Plant island arrangement combined close-cycle gas turbine (point 5)



Approximate Site Area:
960 Ft × 2640 Ft
~ 58 Acres

Railroad Requirements:
1 Mile Spurs
5 Miles to Main Line
6 Miles Total Track

Fig. 7.55—Combined closed-cycle Base Case 1

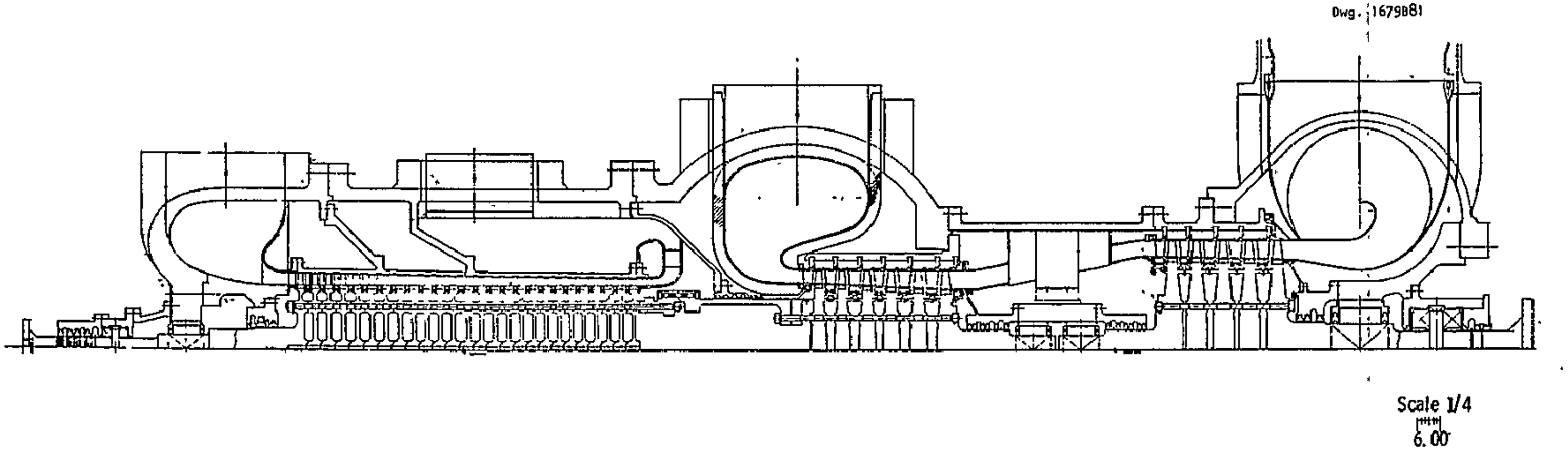


Fig. 7.56—Helium close-cycle gas turbine for the combined plant

of compressor disks as opposed to the integral, welded design. The unit is designed for a net 86 MW electrical output, with a turbine inlet temperature of 1089°K (1500°F). The compressor pressure ratio is 2.5 to 1.

The base case Rankine bottoming cycle consists of a 24.132 MPa (3500 psi) gauge, 755°K/783°K (900°F/950°F) steam turbine generator of 191 MW electrical output.

Principal heat input to the cycle is from a distillate fuel-fired furnace pressurized to 1013 kPa (10 atm). The exhaust heat from each gas turbine is recovered by means of heat recovery vapor generators for the steam bottoming cycle. A four-cell wet cooling tower has been selected to reject waste heat from the helium turbine compressor precooler and the steam cycle condenser.

The overall site requires an area of 190,202 m^2 (47 acres) and is serviced by three 34-car unit train fuel deliveries per week.

During the combined closed-cycle portion of the study, considerable attention was given to the use of organic fluid bottoming cycles. The potential for relatively smaller turbomachinery in conjunction with the use of these fluids has been discussed. A conceptual design for a Rankine cycle turbine using sulfur dioxide working fluid is shown in Figure 7.57. It is interesting to note that the last-row blade size for this 60 rps (3600 rpm) unit of approximately 70 MW net output is just 0.28 m (11 in) in length.

7.5.2 Approximate Sizes and Weights of Major Components

The relatively complex closed-cycle gas turbine systems have enjoyed limited commercial application to date (see Subsection 7.1). Consequently, estimates of major component configurations, particularly with respect to furnaces and heat exchangers, only can be approximate.

A tabulation of the estimated sizes and masses of the major components for these systems is listed in Table 7.10.

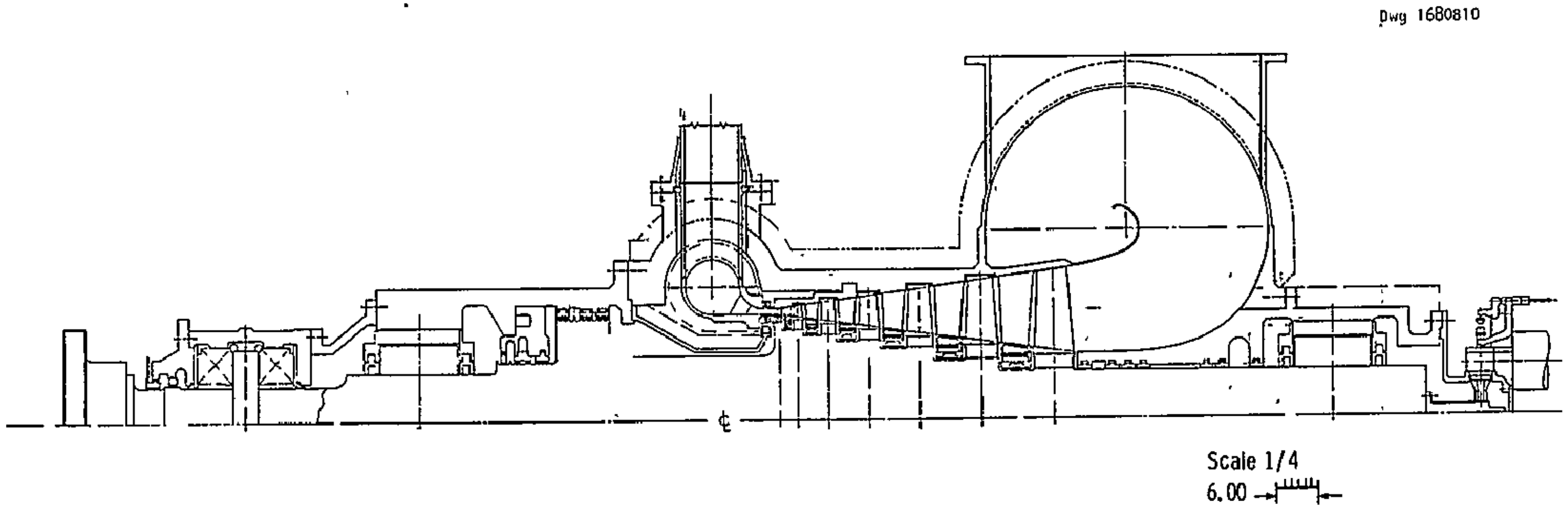


Fig. 7.57—Conceptual design of a sulfur dioxide turbine

Table 7.10 - Approximate Size and Mass of Base Case Closed-Cycle System Major Components

Component	Basic Dimensions	Mass (Weight), lb
Recuperated Closed-Cycle Base Case A (Parametric Point 25)		
Pump-up Gas Turbine		
Turbine section	10.4 ft x 13.8 ft dia	150,000
Compressor section*	19.3 ft x 13.8 ft dia	130,000
Pressurized Furnace	15 ft dia x 100 ft	8,000,000
Helium Gas Turbine		
Turbine section	28 ft x 14.5 ft dia	370,000
Compressor section	21 ft x 12.5 ft dia	190,000
Helium Recuperator	20 ft dia x 150 ft	2,000,000
Recuperated Closed-Cycle Base Case B (Parametric Point 48)		
Atmospheric Furnace (including preheater)	150 ft x 100 ft x 150 ft	28,000,000
Helium Gas Turbine		
Turbine section	30 ft x 14 ft dia	675,000
Compressor section	20 ft x 14 ft dia	250,000
Helium Recuperator	20 ft dia x 150 ft	3,000,000
Combined-Closed Cycle - Base Case (Parametric Point 5)		
Pump-up Gas Turbine		
Turbine section	10.4 ft x 13.8 ft dia	150,000
Compressor section*	19.3 ft x 13.8 ft dia	130,000
Pressurized Furnace	30 ft x 70 ft x 150 ft	8,000,000
Pump-up Vapor Generator	30 ft x 60 ft x 50 ft	1,500,000
Helium Gas Turbine		
Turbine section	20 ft x 11.3 ft dia	160,000
Compressor section	15.4 ft x 9.20 ft dia	120,000
Helium Vapor Generator	15 ft x 50 ft	1,000,000
Steam Turbine Generator	80 ft x 16 ft dia	750,000

*Includes Combustor section.

7.5.3 Price Determination Procedure

The method of determining pump-up gas turbine prices is identical to that used for the open-cycle recuperated and combined gas-steam systems (see Subsection 5.5). Suitable price modifications were made for the turbine combustor shell and the combustor subsystem to account for the full air extraction and the absence of conventional internal combustors.

Closed-cycle helium turbine prices were determined in a manner very similar to that used for the open-cycle gas turbines. Concept designs were prepared and arbitrarily divided into major sections or components. The price for each section was estimated and then functionally related to a principal thermodynamic parameter. Then, as with the open-cycle gas turbines, the price of each parametric point engine was determined as the sum of the prices of its components as found from the functional relationships.

The method of pricing the steam turbine generator was identical to that used in conjunction with the combined gas-steam system and described in Subsection 6.5 of this report.

Because the heat exchange equipment represents a relatively large percentage of the total cost, the prices of these items (including the pressurized furnace, heat recovery vapor generator, intercoolers, and recuperators) play a pivotal role in assessing the closed-cycle energy conversion systems. Very little commercial experience exists, however, in manufacturing such equipment for closed-cycle gas turbine systems. The price estimates for this equipment were, therefore, approximate in nature and should be regarded as such. The procedure used to determine the price of this equipment was first to prepare conceptual designs in several heat exchangers (approach described in Subsection 7.3) and then to prepare price estimates for each. Correlations were then developed to relate parametric variations to the examples. For instance, the resulting correlation developed for the helium recuperator parametric pricing is described below.

$$\text{Recuperator Price, \$} = C_1 \left(1 + \alpha_1\right) \left[1 + C_2 \left(1 + \alpha_2\right) P\right] W^{0.65} \left(\frac{\varepsilon}{1 - \varepsilon}\right)$$

The constants C_1 and C_2 are 10,250 and 0.00094, respectively. P is the nominal shell pressure obtained by dividing the cycle top pressure by the compressor pressure ratio. W is the helium flow rate in lb/s. ε is the recuperator effectiveness, and α_1 and α_2 are adders to account for an increase in price with temperature. The following values were used:

Price Adjustment Factors

Turbine Outlet Temperature	α_1	α_2
T < 833°K (1050°F)	0	0
833°K (1050°F) < T < 894°K (1150°F)	0.15	0.35
894°K (1150°F) < T	0.30	1.00

The two cases with increased pressure drop were individually adjusted according to a general curve for plate-fin recuperators (Figure 5.45), even though these recuperators are assumed to be of the shell-and-tube type. The reduction from the equation price was 6.35% for 4% $\Delta P/P$ and 11% for 6% $\Delta P/P$.

Furnace prices were generated for each of the categories: pressurized and atmospheric pressure, distillate-fired heaters, pressurized fluidized bed fired heater systems, and low-Btu gas-fired heater systems with integrated gasification plants. The total price for each parametric point furnace system was summed from individual components such as (for the pressurized fluidized bed fired heater systems):

Table 7.11 RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM

```
ACCOUNT NO      AUX POWER,MWE   PERC PLANT POW  OPERATION COST MAINTENANCE COST
     4                1.78391        26.35628           .00000        11.26970
     7                1.46407        21.63030        434.16714          .00000
     8                 .19939         2.94591           .00000          .00000
    18                1.58350        23.39530           .00000          .00000
    20                1.73758        25.67171          2.68778          .00000
 TOTALS               6.76845         2.18335        436.85492        11.26970
  RECUPERATED HELIUM CLOSED CYCLE G T SYSTEMBASE CASE INPUT
 NOMINAL POWER, MWE                316.7000   NET POWER, MWE                309.9315
 NOM HEAT RATE, BTU/KW-HR        10449.3259   NET HEAT RATE, BTU/KW-HR    10677.5238
 ST TURB HEAT RATE CHANGE             .0000
 CONDENSER
 DESIGN PRESSURE, IN HG A            2.0000   NUMBER OF SHELLS                 .0000
 NUMBER OF TUBES/SHELL                .0000   TUBE LENGTH, FT                  .0000
 U, BTU/HR-FT2-F                      .0000   TERMINAL TEMP DIFF, F           5.0000
 HEAT REJECTION
 DESIGN TEMP, F                     51.4000   APPROACH, F                    15.0000
 RANGE, F                           15.0000   OFF DESIGN TEMP, F             77.0000
 OFF DESIGN PRES, IN HG A             .0000   LP TURBINE BLADE LEN, IN         .0000

  1          86.100   2          .000   3              .327   4            .000   5          4.500
  6            .000   7         2.000   8              .000   9            .000  10            .000
 11           1.000  12          .000  13             1.000  14            .000  15            .000
 16            .000  17        63.000  18             3.000  19           5.000  20            .000
 21           1.500  22      8500.000  23              .000  24         850.000  25            .000
 26     1000000.000  27      5000.000  28         10000.000  29      500000.000  30            .300
 31            .750  32       100.000  33              .000  34            .600  35            .700
 36      954000.000  37          .000  38             1.000  39           1.000  40      300000.000
 41       50000.000  42    550000.000  43         12000.000  44      250000.000  45      150000.000
 46            .000  47          .250  48             3.000  49           1.000  50            .000
 51           1.000  52         5.350
  1           1.000   2   44850000.000   3             .300   4           1.000   5           1.000
  6           1.000   7         1.000   8             1.000   9            .000  10      746000.000
 11            .100  12   2730000.000  13              .050  14     4030000.000  15            .050
 16     2880000.000  17          .140  18       4230000.000  19            .090  20            .000
 21            .000  22          .000  23              .000  24            .000  25            .000
 26            .000  27          .000  28              .000  29           1.000  30            .000
 31            .000  32          .150  33       3940000.000  34            .150  35            .000
 36            .000  37    910000.000  38              .140  39      350000.000  40            .140
 41          89.100  42       230.600  43    1271000000.000  44           1.000  45            .000
 46            .000  47          .000  48              .000  49           1.000  50            .000
```

- Heater modules
- Coal and dolomite preparation equipment
- Coal and dolomite feeding equipment
- Solid waste handling equipment
- Particulate removal equipment
- Special piping.

Section 2 of this report describes the balance of plant pricing methods utilized by the architect/engineering firm, Chas. T. Main, Inc.

7.5.4 Tabulation of Overall Plant Material and Installation Costs

As described in Subsection 6.5.4, the prices for steam turbine condensers, cooling towers, and related installation costs have been calculated by price correlations preprogrammed into the cost of electricity calculation. The prices of remaining items were determined by means of the methods described above.

The price and heat rejection input for the recuperated cycle Base Case A (Point R25) as used in the computer program is given in Table 7.11. Similar input for the recuperated cycle Base Case B (Point R48) and the combined closed-cycle base case (Point C5) are given in Tables 7.12 and 7.13, respectively.

Prices and installation costs have also been prepared according to account code category (including such headings as Site Development, Excavation and Piling, Plant Island Concrete, etc.). This tabulation for the recuperated closed-cycle Base Case A is shown in Table 7.14, and similar listings for the recuperated closed-cycle Base Case B and the combined closed-cycle base case are shown in Tables 7.15 and 7.16, respectively. Both unit and total quantity costs are listed in addition to the percent of the total equipment and installation cost contained within each particular account code.

Table 7.17 gives similar cost tabulations for the remaining parametric points of the recuperated closed-cycle system, and the

Table 7.12 RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM

```
ACCOUNT NO       AUX POWER,MWE    PERC PLANT POW  OPERATION COST MAINTENANCE COST
       4                 2.75596          60.09116          .00000         17.70620
      19                 1.83100          39.90883          .00000           .00000
 TOTALS                  4.58796           1.26875          .00000         17.70620
  RECUPERATED HELIUM CLOSED CYCLE C T SYSTEMBASE CASE INPUT
 NOMINAL POWER, MWE               366.2000    NET POWER, MWE                   361.6120
 NOM HEAT RATE, BTU/KW-HR       10360.7979    NET HEAT RATE, BTU/KW-HR       10498.3265
 ST TURB HEAT RATE CHANGE            .0000
 CONDENSER
 DESIGN PRESSURE, IN HG A           2.0000    NUMBER OF SHELLS                    .0000
 NUMBER OF TUBES/SHELL               .0000    TUBE LENGTH, FT                     .0000
 U, BTU/HR-FT2-F                     .0000    TERMINAL TEMP DIFF, F              5.0000
 HEAT REJECTION
 DESIGN TEMP, F                     51.4000   APPROACH, F                        15.0000
 RANGE, F                           15.0000   OFF DESIGN TEMP, F                 77.0000
 OFF DESIGN PRES, IN HG A            .0000    LP TURBINE BLADE LEN, IN             .0000

  1            .000  2            .000  3             .329  4          .000  5        4.500
  6            .000  7           2.000  8             .000  9          .000 10         .000
 11           1.000 12            .000 13            1.000 14         1.000 15         .000
 16            .000 17          43.000 18            3.000 19         5.000 20         .000
 21           1.000 22       11000.000 23             .000 24       750.000 25      400.000
 26     1300000.000 27        5000.000 28        10000.000 29   9400000.000 30         .200
 31            .500 32         110.000 33             .000 34          .700 35         .700
 36      735000.000 37            .000 38            1.000 39         1.000 40   254000.000
 41       99000.000 42      350000.000 43        10000.000 44     50000.000 45    36000.000
 46            .000 47            .000 48            3.000 49         1.000 50        6.000
 51            .000 52           5.350
  1           1.000  2     55490000.000  3             .300  4          .000  5        1.000
  6           1.000  7           1.000  8            1.000  9          .000 10         .000
 11            .000 12      3660000.000 13             .050 14   7370000.000 15         .050
 16     3940000.000 17            .140 18      6910000.000 19          .090 20         .000
 21            .000 22            .000 23             .000 24          .000 25         .000
 26            .000 27            .000 28            1.000 29         1.000 30         .000
 31     7650000.000 32            .150 33     13430000.000 34          .150 35        1.000
 36           1.000 37      143000.000 38             .140 39    540000.000 40         .140
 41            .000 42         366.200 43   2019000000.000 44          .000 45        2.000
 46            .000 47            .000 48             .000 49         1.000 50         .000
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Table 7.13      COMBINED AIR-HELIUM-STEAM TURB CYCLE

ACCOUNT NO      AUX POWER,MWE   PERC PLANT POW  OPERATION COST MAINTENANCE COST
       4              3.15585        50.45688         17.55679          4.86329
      14               .00000          .00000          3.30889           .00000
      18              3.39870        49.54312           .00000           .00000
 TOTALS               6.25455         1.62860         20.87567          4.86329
     COMBINED AIR-HELIUM-STEAM TURB CYCLE  BASE CASE INPUT
 NOMINAL POWER, MWE                390.3000    NET POWER, MWE                 384.0459
 NOM HEAT RATE, BTU/KW-HR         8215.5752    NET HEAT RATE, BTU/KW-HR      8349.3737
 ST TURB HEAT RATE CHANGE             .0000
 CONDENSER
 DESIGN PRESSURE, IN HG A            2.0000    NUMBER OF SHELLS                 1.0000
 NUMBER OF TUBES/SHELL            6587.3370    TUBE LENGTH, FT                 77.4467
 U, BTU/HR-FT2-F                   591.4577    TERMINAL TEMP DIFF, F            5.0000
 HEAT REJECTION
 DESIGN TEMP, F                     51.4000    APPROACH, F                     21.6744
 RANGE, F                           23.3000    OFF DESIGN TEMP, F              77.0000
 OFF DESIGN PRES, IN HG A             .0000    LP TURBINE BLADE LEN, IN        25.0000

  1        112.800   2          .000   3           .415   4          .000   5          5.000
  6        191.200   7         2.000   8 1076000000.000   9         1.000  10          1.000
 11          1.000  12          .000  13          1.000  14         1.000  15           .000
 16          2.000  17        58.000  18          3.000  19         5.000  20           .000
 21          1.000  22     13275.000  23           .000  24      1285.000  25           .000
 26    3631500.000  27          .000  28       5000.000  29   8100000.000  30           .500
 31          1.000  32       750.000  33           .000  34         1.000  35          1.000
 36    1200000.000  37       300.000  38          1.000  39         1.000  40     322000.000
 41      77000.000  42    550000.000  43      12000.000  44    250000.000  45     150000.000
 46           .000  47          .000  48          3.000  49         1.000  50          6.000
 51           .000  52         5.350
  1          1.000   2   1916000.000   3           .300   4         1.000   5          1.000
  6          1.000   7         1.000   8          1.000   9         1.000  10    7410000.000
 11           .100  12   1750000.000  13           .050  14   1750000.000  15           .050
 16    1333000.000  17          .140  18    1970000.000  19          .090  20    6350000.000
 21           .080  22         1.000  23          1.000  24   3220000.000  25           .300
 26    8500000.000  27          .300  28           .000  29          .000  30           .000
 31           .000  32          .000  33           .000  34          .000  35           .000
 36           .000  37    335000.000  38           .140  39          .230  40           .140
 41        112.800  42        86.300  43    2220000.000  44          .000  45           .000
 46           .000  47          .000  48           .000  49         1.000  50          1.000
 51           .000  52          .000  53        325.000  54      2500.000  55       1000.000
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Table 7.14 RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM ACCOUNT LISTING
                         PARAMETRIC POINT NO.25

 ACCOUNT NO. & NAME,     UNIT      AMOUNT  MAT $/UNIT  INS $/UNIT  MAT COST,$  INS COST,$


SITE DEVELOPMENT
 1. 1 LAND COST          ACRE        63.0     1000.00         .00    63000.00         .00
 1. 2 CLEARING LAND      ACRE        21.0         .00      600.00         .00    12598.74
 1. 3 GRADING LAND       ACRE        63.0         .00     3000.00         .00   189000.00
 1. 4 ACCESS RAILROAD    MILE         5.0   115000.00   110000.00   575000.00   550000.00
 1. 5 LOOP RAILROAD TRACK MILE         .0   120000.00    70000.00         .00         .00
 1. 6 SIDING R R TRACK   MILE         1.5   125000.00    80000.00   187500.00   120000.00
 1. 7 OTHER SITE COSTS   ACRE          .0         .00         .00   147122.78   147122.78
 PERCENT TOTAL DIRECT COST IN ACCOUNT  1 = 1.524 ACCOUNT TOTAL,$  972622.78  1018721.52

EXCAVATION & PILING
 2. 1 COMMON EXCAVATION   YD3     24400.0         .00        3.00         .00    73200.00
 2. 2 PILING               FT     70400.0        6.50        8.50   457600.00   598400.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  2 =  .869 ACCOUNT TOTAL,$  457600.00   677600.00

PLANT ISLAND CONCRETE
 3. 1 PLANT IS. CONCRETE  YD3      8800.0       70.00       80.00   616000.00   704000.00
 3. 2 SPECIAL STRUCTURES  YD3          .0         .00         .00         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  3 = 1.010 ACCOUNT TOTAL,$  616000.00   704000.00

HEAT REJECTION SYSTEM
 4. 1 COOLING TOWERS     EACH        11.0         .00         .00  1688500.00   841500.00
 4. 2 CIRCULATING H2O SYS EACH        1.0         .00         .00   601687.30   789815.50
 4. 3 HELIUM PRECOOLER    EACH         .0         .00         .00  2393999.97   266000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT, 4 = 5.036 ACCOUNT TOTAL,$ 4684187.25  1897315.48

STRUCTURAL FEATURES
 5. 1 STAT. STRUCTURAL ST. TON      850.0      650.00      175.00   552500.00   148750.00
 5. 2 SILOS & BUNKERS     TPH          .0     1900.00      750.00         .00         .00
 5. 3 CHIMNEY              FT          .0         .00         .00         .00         .00
 5. 4 STRUCTURAL FEATURES EACH        1.0   300000.00    50000.00   300000.00    50000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  5 =  .804 ACCOUNT TOTAL,$  852500.00   198750.00

BUILDINGS
 6. 1 STATION BUILDINGS   FT3  1000000.0         .16         .16   160000.00   160000.00
 6. 2 ADMINSTRATION       FT2      5000.0       16.00       14.00    80000.00    70000.00
 6. 3 WAREHOUSE & SHOP    FT2     10000.0       12.00        9.00   120000.00    90000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  6 =  .513 ACCOUNT TOTAL,$  360000.00   310000.00

FUEL HANDLING & STORAGE
 7. 1 COAL HANDLING SYS   TPH       155.4         .00         .00  2360375.72  1243888.53
 7. 2 DOLOMITE HAND. SYS  TPH        61.2         .00         .00  1329857.69   599292.16
 7. 3 FUEL OIL HAND. SYS  GAL    560000.0         .00         .00    76378.21    60848.53
 PERCENT TOTAL DIRECT COST IN ACCOUNT  7 = 4.339 ACCOUNT TOTAL,$ 3766611.59  1904029.22

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
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Table 7.14 Continued

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RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM ACCOUNT LISTING
                      PARAMETRIC POINT NO.25

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 PRESSURIZED HE FURNACE              1.0 44850000.00 13455000.00 44850000.00 13455000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =44.611 ACCOUNT TOTAL,$  44850000.00 13455000.00

ENERGY CONVERTER
11. 1 PUMP UP GT-GEN & AUX                1.0  7460000.00   745999.99  7460000.00   745999.99
11. 2 HE TURB COMPRESSOR SECT             1.0  2730000.00   136500.00  2730000.00   136500.00
11. 3 HE TURB TURBINE SECT                1.0  4030000.00   201500.00  4030000.00   201500.00
11. 4 HE TURB AUXILIARIES                 1.0  2880000.00   403200.00  2880000.00   403200.00
11. 5 HE TURB-GEN & EXCITER               1.0  4230000.00   380700.00  4230000.00   380700.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =17.749 ACCOUNT TOTAL,$  21330000.00  1867899.99

COUPLING HEAT EXCHANGER
12. 1                                      .0        .00         .00         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 12 =  .000 ACCOUNT TOTAL,$             .00         .00

HEAT RECOVERY HEAT EXCH.
13. 1 PUMP UP RECUPERATOR                  .0        .00         .00         .00         .00
13. 2 HELIUM RECUPERATOR                  1.0  9940000.00  1491000.00  9940000.00  1491000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = 9.745 ACCOUNT TOTAL,$   9940000.00  1491000.00

WATER TREATMENT
14. 1 DEMINERALIZER          GPM           .0     2500.00      700.00         .00         .00
14. 2 CONDENSATE POLISHING   KWE           .0        1.25         .30         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 14 =  .000 ACCOUNT TOTAL,$             .00         .00

POWER CONDITIONING
15. 1 STD TRANSFORMER        KVA    1053?7.3         .00         .00  1531776.48    30635.53
 PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.195 ACCOUNT TOTAL,$   1531776.48    30635.53

AUXILIARY MECH EQUIPMENT
16. 1 BOILER FEED PUMP PWR.KWE             .0        .55         .04         .00         .00
16. 2 OTHER PUMPS            KWE    114428.9         .88         .12   100697.42    13731.47
16. 3 MISC SERVICE SYS       KWE    286072.2        1.17         .73   334704.50   208832.72
16. 4 AUXILIARY BOILER       PPH           .0       4.00         .80         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 16 =  .503 ACCOUNT TOTAL,$    435401.91   222564.19

PIPE & FITTINGS
17. 1 CONVENTIONAL PIPING    TON       100.0     3000.00     1800.00   300000.00   180000.00
17. 2 HOT GAS PIPING          FT       290.0     5600.00     2250.00  1624000.00   652500.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 2.109 ACCOUNT TOTAL,$   1924000.00   832500.00
```

Table 7.14 RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM ACCOUNT LISTING
Continued

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                              PARAMETRIC POINT NO.25
ACCOUNT NO. & NAME,     UNIT      AMOUNT  MAT $/UNIT  INS $/UNIT  MAT COST,$  INS COST,$


AUXILIARY ELEC EQUIPMENT
18. 1 MISC MOTERS,ETC              228857.8        1.40         .17   320400.89    38905.92
18. 2 SWITCHGEAR & MCC PAN KWE     267000.7        1.95         .45  1430651.44   120150.33
18. 3 CONDUIT,CABLES,TRAYS  FT     954000.0        1.32        1.36  1259279.98  1297439.98
18. 4 ISOLATED PHASE BUS    FT           .0      510.00      450.00         .00         .00
18. 5 LIGHTING & COMMUN    KWE     381429.6         .35         .43   133500.37   164014.74
 PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 3.645 ACCOUNT TOTAL,$  3143832.62  1620510.86

CONTROL, INSTRUMENTATION
19. 1 COMPUTER            EACH        1.0   900000.00    12000.00   900000.00    12000.00
19. 2 OTHER CONTROLS      EACH        1.0   250000.00   150000.00   250000.00   150000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = 1.004 ACCOUNT TOTAL,$  1150000.00   162000.00

PROCESS WASTE SYSTEMS
20. 1 BOTTOM ASH           TPH         .0         .00         .00         .00         .00
20. 2 DRY ASH              TPH       14.7  1012042.95   253010.74  1012042.95   253010.74
20. 3 WET SLURRY           TPH       81.2  2144922.22   536230.55  2144922.22   536230.55
20. 4 ONSITE DISPOSAL     ACRE      268.9     6502.54     9650.72  1748335.97  2594784.69
 PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 6.342 ACCOUNT TOTAL,$  4905301.12  3384025.97

STACK GAS CLEANING
21. 1 PRECIPITATOR        EACH         .0  3497406.53  5770720.75         .00         .00
21. 2 SCRUBBER             KWE         .0       20.23        8.73         .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,$                                     100919831.00   29776550.75
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Table 7.15 RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM ACCOUNT LISTING
PARAMETRIC POINT NO.49

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 ACCOUNT NO. & NAME,      UNIT       AMOUNT  MAT $/UNIT  INS $/UNIT  MAT COST,$  INS COST,$


SITE DEVELOPMENT.
 1. 1 LAND COST             ACRE          43.0     1000.00         .00    43000.00         .00
 1. 2 CLEARING LAND         ACRE          14.3         .00      600.00         .00     8599.14
 1. 3 GRADING LAND          ACRE          43.0         .00     3000.00         .00   129000.00
 1. 4 ACCESS RAILROAD       MILE           5.0   115000.00   110000.00   575000.00   550000.00
 1. 5 LOOP RAILROAD TRACK   MILE            .0   120000.00    70000.00         .00         .00
 1. 6 SIDING R R TRACK      MILE           1.0   125000.00    90000.00   125000.00    90000.00
 1. 7 OTHER SITE COSTS      ACRE            .0         .00         .00   102410.61   102410.61
 PERCENT TOTAL DIRECT COST IN ACCOUNT  1 = 1.146 ACCOUNT TOTAL,$         845410.61   870009.74

EXCAVATION & PILING
 2. 1 COMMON EXCAVATION     YD3        33000.0         .00        3.00         .00    99000.00
 2. 2 PILING                 FT        88000.0        6.50        8.50   572000.00   748000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  2 =  .948 ACCOUNT TOTAL,$         572000.00   847000.00

PLANT ISLAND CONCRETE
 3. 1 PLANT IS. CONCRETE    YD3        11000.0       70.00       80.00   770000.00   880000.00
 3. 2 SPECIAL STRUCTURES    YD3             .0         .00         .00         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  3 = 1.103 ACCOUNT TOTAL,$         770000.00   880000.00

HEAT REJECTION SYSTEM
 4. 1 COOLING TOWERS        EACH          17.0         .00         .00  2599500.00  1300500.00
 4. 2 CIRCULATING H2O SYS   EACH           1.0         .00         .00   955788.10  1254632.17
 4. 3 HELIUM PRECOOLER      EACH            .0         .00         .00  3797999.97   422000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  4 = 6.910 ACCOUNT TOTAL,$        7353288.06  2977132.12

STRUCTURAL FEATURES
 5. 1 STAT. STRUCTURAL ST.  TON          750.0      650.00      175.00   487500.00   131250.00
 5. 2 SILOS & BUNKERS       TPH             .0     1800.00      750.00         .00         .00
 5. 3 CHIMNEY                FT          400.0         .00         .00   435070.92   658606.38
 5. 4 STRUCTURAL FEATURES   EACH           1.0    54000.00    93000.00   254000.00    93000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  5 = 1.376 ACCOUNT TOTAL,$        1176570.92   882856.38

BUILDINGS
 6. 1 STATION BUILDINGS     FT3      1300000.0         .16         .15   208000.00   195000.00
 6. 2 ADMINSTRATION         FT2         5000.0       16.00       14.00    80000.00    70000.00
 6. 3 WAREHOUSE & SHOP      FT2        10000.0       12.00        9.00   120000.00    90000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  6 =  .512 ACCOUNT TOTAL,$         408000.00   355000.00

FUEL HANDLING & STORAGE
 7. 1 COAL HANDLING SYS     TPH             .0         .00         .00         .00         .00
 7. 2 DOLOMITE HAND. SYS    TPH             .0         .00         .00         .00         .00
 7. 3 FUEL OIL HAND. SYS    GAL      9400000.0         .00         .00   849760.00   637613.41
 PERCENT TOTAL DIRECT COST IN ACCOUNT  7 =  .994 ACCOUNT TOTAL,$         849760.00   637613.41

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
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Table 7.15 RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM ACCOUNT LISTING
Continued

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                                    PARAMETRIC POINT NO.49
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 PRESSURIZED HE FURNACE           1.0 55490000.00 16647000.00 55490000.00 16647000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =48.208 ACCOUNT TOTAL,$  55490000.00 16647000.00


ENERGY CONVERTER
11. 1 PUMP UP GT-GEN & AUX              .0         .00         .00         .00         .00
11. 2 HE TURB COMPRESSOR SECT          1.0  3660000.00   183000.00  3660000.00   183000.00
11. 3 HE TURB TURBINE SECT             1.0  7370000.00   368500.00  7370000.00   368500.00
11. 4 HE TURB AUXILIARIES              1.0  3940000.00   551500.00  3940000.00   551500.00
11. 5 HE TURB-GEN & EXCITER            1.0  6810000.00   612999.99  6810000.00   612999.99
 PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =15.702 ACCOUNT TOTAL,$  21780000.00  1715999.97

COUPLING HEAT EXCHANGER
12. 1                                   .0         .00         .00         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 12 =  .000 ACCOUNT TOTAL,$           .00         .00

HEAT RECOVERY HEAT EXCH.
13. 1 PUMP UP RECUPERATOR              1.0  7650000.00  1147500.00  7650000.00  1147500.00
13. 2 HELIUM RECUPERATOR               1.0 13430000.00  2014500.00 13430000.00  2014500.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 13 =16.200 ACCOUNT TOTAL,$  21080000.00  3162000.00

WATER TREATMENT
14. 1 DEMINERALIZER         GPM         .0     2500.00      700.00         .00         .00
14. 2 CONDENSATE POLISHING KWE          .0        1.25         .30         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 14 =  .000 ACCOUNT TOTAL,$           .00         .00

POWER CONDITIONING
15. 1 STD TRANSFORMER       KVA         .0         .00         .00  1092413.99    21549.28
 PERCENT TOTAL DIRECT COST IN ACCOUNT 15 =  .738 ACCOUNT TOTAL,$   1092413.99    21549.28

AUXILIARY MECH EQUIPMENT
16. 1 BOILER FEED PUMP RDR.KWE          .0         .55         .04         .00         .00
16. 2 OTHER PUMPS           KWE    85834.4         .88         .12    75534.31    10300.13
16. 3 MISC SERVICE SYS      KWE   214586.1        1.17         .73   251065.74   156647.85
16. 4 AUXILIARY BOILER      PPH         .0        4.00         .80         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 16 =  .330 ACCOUNT TOTAL,$    326600.04   166947.98

PIPE & FITTINGS
17. 1 CONVENTIONAL PIPING   TON      110.0     3000.00     1800.00   330000.00   198000.00
17. 2 HOT GAS PIPING         FT      290.0     5600.00     2250.00  1624000.00   652500.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 1.874 ACCOUNT TOTAL,$   1954000.00   850500.00
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Table 7.15 RECUPERATED HELIUM CLOSED CYCLE C T SYSTEM ACCOUNT LISTING
Continued

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                                PARAMETRIC POINT NO.48
ACCOUNT NO. & NAME.     UNIT      AMOUNT  MAT $/UNIT  INS $/UNIT  MAT COST,$  INS COST,$


AUXILIARY ELEC EQUIPMENT
18. 1 MISC MOTERS,ETC             300420.5        1.40         .17   420588.76    51071.49
18. 2 SWITCHGEAR & MCC PAN KWE    300420.5        1.95         .45  2015820.05   135189.24
18. 3 CONDUIT,CABLES,TRAYS  FT    735000.0        1.32        1.36   970199.99   999599.99
18. 4 ISOLATED PHASE BUS    FT          .0      510.00      450.00         .00         .00
18. 5 LIGHTING & COMMON     KWE   429173.2         .35         .43   150210.27   184544.05
 PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 3.293 ACCOUNT TOTAL,$    3556819.00  1370404.77

CONTROL, INSTRUMENTATION
19. 1 COMPUTER            EACH         1.0   550000.00    10000.00   890000.00    10000.00
19. 2 OTHER CONTROLS      EACH         1.0    60000.00    35000.00    60000.00    35000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 19 =  .566 ACCOUNT TOTAL,$     950000.00    45000.00

PROCESS WASTE SYSTEMS
20. 1 BOTTOM ASH          TPH           .0         .00         .00         .00         .00
20. 2 DRY ASH             TPH           .0         .00         .00         .00         .00
20. 3 WET SLURRY          TPH           .0         .00         .00         .00         .00
20. 4 ONSITE DISPOSAL     ACRE          .0     7676.49    11070.99         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 20 =  .000 ACCOUNT TOTAL,$           .00         .00

STACK GAS CLEANING
21. 1 PRECIPITATOR        EACH         2.0         .00         .00         .00         .00
21. 2 SCRUBBER            KWE           .0       19.26        8.31         .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,$                                            118204861.00 31433117.00
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Table 7.16     COMBINED AIR-HELIUM-STEAM TURB CYCLE   ACCOUNT LISTING
                          PARAMETRIC POINT NO. 5

 ACCOUNT NO. & NAME,     UNIT  .  AMOUNT  MAT $/UNIT  INS $/UNIT  MAT COST,$  INS COST,$


SITE DEVELOPMENT
 1. 1 LAND COST               ACRE        58.0     1000.00         .00    58000.00         .00
 1. 2 CLEARING LAND           ACRE        19.3         .00      600.00         .00    11598.84
 1. 3 GRADING LAND            ACRE        58.0         .00     3000.00         .00   174000.00
 1. 4 ACCESS RAILROAD         MILE         5.0   115000.00   110000.00   575000.00   550000.00
 1. 5 LOOP RAILROAD TRACK     MILE          .0   120000.00    70000.00         .00         .00
 1. 6 SIDING R R TRACK        MILE         1.0   125000.00    80000.00   125000.00    80000.00
 1. 7 OTHER SITE COSTS        ACRE          .0         .00         .00   136097.86   136097.86
 PERCENT TOTAL DIRECT COST IN ACCOUNT  1 = 2.019 ACCOUNT TOTAL,$        894097.85   951696.69


EXCAVATION & PILING
 2. 1 COMMON EXCAVATION       YD3      39825.0         .00        3.00         .00   119475.00
 2. 2 PILING                  FT      106203.0        5.50        8.50   690300.00   902700.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  2 = 1.873 ACCOUNT TOTAL,$        690300.00  1022175.00


PLANT ISLAND CONCRETE
 3. 1 PLANT IS. CONCRETE      YD3      13275.0       70.00       80.00   929250.00  1062000.00
 3. 2 SPECIAL STRUCTURES      YD3           .0         .00         .00         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  3 = 2.178 ACCOUNT TOTAL,$        929250.00  1062000.00


HEAT REJECTION SYSTEM
 4. 1 COOLING TOWERS          EACH         6.0         .00         .00   921000.00   459000.00
 4. 2 CIRCULATING H2O SYS     EACH         1.0         .00         .00   360961.63   484003.93
 4. 3 STM SURFACE COND        FT2     135589.0         .00         .00   615194.33         .00
 4. 4 ORGANIC VAPOR COND                    .0         .00         .00         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  4 = 3.106 ACCOUNT TOTAL,$       1897155.95   943003.93


STRUCTURAL FEATURES
 5. 1 STAT. STRUCTURAL ST.    TON       1285.0      650.00      175.00   835250.00   224875.00
 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   322000.00    77000.00   322000.00    77000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  5 = 1.596 ACCOUNT TOTAL,$       1157250.00   301875.00


BUILDINGS
 6. 1 STATION BUILDINGS       FT3    3631500.0         .16         .16   581040.00   581040.00
 6. 2 ADMINSTRATION           FT2           .0       16.00       14.00         .00         .00
 6. 3 WAREHOUSE & SHOP        FT2       5000.0       12.00        8.00    60000.00    40000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT  6 = 1.380 ACCOUNT TOTAL,$        641040.00   521040.00


FUEL HANDLING & STORAGE
 7. 1 COAL HANDLING SYS       TPH           .0         .00         .00         .00         .00
 7. 2 DOLOMITE HAND. SYS      TPH           .0         .00         .00         .00         .00
 7. 3 FUEL OIL HAND. SYS      GAL    8100000.0         .00         .00   732240.00   565969.99
 PERCENT TOTAL DIRECT COST IN ACCOUNT  7 = 1.420 ACCOUNT TOTAL,$        732240.00   565969.99


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
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Table 7.16
Continued

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              COMBINED AIR-HELIUM-STEAM TURE 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 PRESSURIZED HE FURNACE                  1.0 19160000.00  5748000.00 19160000.00  5748000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =27.241 ACCOUNT TOTAL,$          19160000.00  5748000.00


ENERGY CONVERTER
11. 1 PUMP UP ST-GEN & AUX                    1.0  7410000.00   740999.99  7410000.00   740999.99
11. 2 HE TURB COMPRESSOR SECT                 1.0  1750000.00    87500.00  1750000.00    87500.00
11. 3 HE TURB TURBINE SECT                    1.0  1750000.00    87500.00  1750000.00    87500.00
11. 4 HE TURB AUXILIARIES                     1.0  1330000.00   186200.00  1330000.00   186200.00
11. 5 HE TURB-GEN & EXCITER                   1.0  1870000.00   168300.00  1870000.00   168300.00
11. 6 STEAM TURBINE-GEN & AUX                 1.0  7909649.12   632771.93  7909649.12   632771.93
 PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =26.163 ACCOUNT TOTAL,$          22019649.00  1903271.87


COUPLING HEAT EXCHANGER
12. 1 PUMP UP HEAT REC VAP GEN                1.0  3220000.00   966000.00  3220000.00   966000.00
12. 2 HE TURB VAPOR GEN                       1.0  8500000.00  2550000.00  8500000.00  2550000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 12 =16.663 ACCOUNT TOTAL,$          11720000.00  3516000.00


HEAT RECOVERY HEAT EXCH.
13. 1 PUMP UP RECUPERATOR                      .0         .00         .00         .00         .00
13. 2 HELIUM RECUPERATOR                       .0         .00         .00         .00         .00
13. 3 DESUPERHEAT RECUPERATOR                  .0         .00         .00         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 13 =  .000 ACCOUNT TOTAL,$                  .00         .00


WATER TREATMENT
14. 1 DEMINERALIZER          GPM          30.6     2500.00      700.00    76480.00    21414.40
14. 2 CONDENSATE POLISHING KWE      191200.0        1.25         .30   239000.00    57360.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 14 =  .431 ACCOUNT TOTAL,$            315480.00    78774.40


POWER CONDITIONING
15. 1 STD TRANSFORMER        KVA    477033.3         .00         .00  1634530.30    32690.61
 PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.823 ACCOUNT TOTAL,$           1634530.30    32690.61


AUXILIARY MECH EQUIPMENT
16. 1 BOILER FEED PUMP &DR.KWE      221227.3         .55         .04   121675.00     8849.09
16. 2 OTHER PUMPS            KWE    225797.6         .88         .12   198701.90    27095.71
16. 3 MISC SERVICE SYS       KWE    451595.2        1.17         .73   528366.41   329664.52
16. 4 AUXILIARY BOILER       PPH          .0        4.00         .80         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 1.328 ACCOUNT TOTAL,$            848743.31   365609.32


PIPE & FITTINGS
17. 1 CONVENTIONAL PIPING  TON         750.0     3000.00     1800.00  2250000.00  1350000.00
17. 2 HOT GAS PIPING         FT        325.0     2500.00     1000.00   812500.00   325000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 5.181 ACCOUNT TOTAL,$           3062500.00  1675000.00
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Table 7.16 COMBINED AIR-HELIUM-STEAM TURB CYCLE ACCOUNT LISTING
Continued
PARAMETRIC POINT NO. 5

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ACCOUNT NO. & NAME,    UNIT      AMOUNT  MAT $/UNIT  INS $/UNIT  MAT COST,$  INS COST,$

AUXILIARY ELEC EQUIPMENT
18. 1 MISC MOTERS,ETC              451595.2        1.40         .17   632233.32    76771.19
18. 2 SWITCHGEAR & MCC PAN KWE     451595.2        1.95         .45  1216610.69   203217.85
18. 3 CONDUIT,CABLES,TRAYS  FT    1200000.0        1.32        1.36  1583999.98  1631999.98
18. 4 ISOLATED PHASE BUS    FT        300.0      510.00      450.00   153000.00   135000.00
18. 5 LIGHTING & COMMUN    KWE     451595.2         .35         .43   158058.33   194185.95
 PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 6.546 ACCOUNT TOTAL,$  3743902.28  2241174.94

CONTROL, INSTRUMENTATION
19. 1 COMPUTER             EACH         1.0   550000.00    12000.00   550000.00    12000.00
19. 2 OTHER CONTROLS       EACH         1.0   250000.00   150000.00   250000.00   150000.00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = 1.052 ACCOUNT TOTAL,$   800000.00   162000.00

PROCESS WASTE SYSTEMS
20. 1 BOTTOM ASH            TPH          .0         .00         .00         .00         .00
20. 2 DRY ASH               TPH          .0         .00         .00         .00         .00
20. 3 WET SLURRY            TPH          .0         .00         .00         .00         .00
20. 4 ONSITE DISPOSAL      ACRE          .0     7676.49    11070.89         .00         .00
 PERCENT TOTAL DIRECT COST IN ACCOUNT 20 =  .000 ACCOUNT TOTAL,$         .00         .00

STACK GAS CLEANING
21. 1 PRECIPITATOR         EACH          .0         .00         .00         .00         .00
21. 2 SCRUBBER              KWE          .0       20.45        8.82         .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,$                                     70246137.00  21190281.25
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Table 7.17 - RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM SUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT		1	2	3	4	5	6	7	8
	TOTAL CAPITAL COST	,M$	153.52	149.45	142.30	132.67	191.17	176.55	170.62	161.16
P	PRESS HE FURNACE	,M$	12.680	12.440	12.300	12.060	24.380	23.640	23.190	22.480
L	PUMP UP GT-GEN	,M$	7.410	7.410	7.410	7.410	7.410	7.410	7.410	7.410
A	HELIUM GAS TURB-GEN	,M$	13.890	12.885	11.770	10.430	13.760	13.070	12.480	11.490
N	PUMP UP RECUPERATOR & PIPING		9.261	9.261	9.261	9.261	9.261	9.261	9.261	9.261
T	HELIUM RECUPERATOR & PIPING		13.130	10.820	9.530	8.110	14.830	9.550	8.410	7.000
R	TOT MAJOR COMPONENT COST	,M$	56.371	52.816	50.271	47.271	69.641	62.931	60.741	57.641
E	TOT MAJOR COMPONENT COST	,$/KWE	198.061	189.007	187.054	203.479	215.286	193.531	191.483	196.370
S	BALANCE OF PLANT COST	,$/KWE	62.122	59.342	59.153	62.402	55.295	52.680	52.031	52.608
U	SITE LABOR	,$/KWE	60.286	59.186	60.165	65.565	65.694	61.921	61.955	64.168
L	TOTAL DIRECT COST	,$/KWE	320.463	307.534	306.373	331.447	336.274	308.132	305.519	313.146
T	INDIRECT COSTS	,$/KWE	30.746	30.185	30.694	33.438	33.504	31.580	31.597	32.725
	PROF & OWNER COSTS	,$/KWE	25.637	24.603	24.670	26.516	26.902	24.651	24.441	25.052
B	CONTINGENCY COST	,$/KWE	24.035	23.021	22.965	24.343	25.560	23.434	23.174	23.560
R	ESCALATION COST	,$/KWE	73.184	70.101	69.635	73.032	78.980	72.610	71.695	72.432
E	INT DURING CONSTRUCTION	,$/KWE	82.892	79.361	78.798	82.288	89.761	82.533	81.439	82.106
A	TOTAL CAPITALIZATION	,$/KWE	556.962	534.805	535.164	571.065	590.982	542.938	537.866	549.021
K	COST OF ELEC-CAPITAL	,MILLS/KWE	17.607	16.906	16.918	18.053	18.682	17.163	17.003	17.356
D	COST OF ELEC-FUEL	,MILLS/KWE	29.285	29.833	31.354	35.880	26.311	25.641	26.276	28.401
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.548	.548	.548	.548	.548	.548	.548	.548
W	TOTAL COST OF ELEC	,MILLS/KWE	47.439	47.288	48.820	54.480	45.542	43.352	43.827	46.305
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	52.833	52.471	54.007	60.008	51.258	48.613	49.039	51.623
	COE 0.8 CAP. FACTOR	,MILLS/KWE	44.064	44.043	45.573	51.021	41.964	40.050	40.564	42.976
	COE 1.2XCAP. COST	,MILLS/KWE	50.961	50.669	52.203	58.091	49.278	46.785	47.227	49.776
	COE 1.2XFUEL COST	,MILLS/KWE	53.296	53.254	55.091	61.656	50.804	49.481	49.082	51.995
	COE (CONTINGENCY=0)	,MILLS/KWE	45.364	45.278	47.515	53.423	44.411	42.315	42.803	45.268
	COE (ESCALATION=0)	,MILLS/KWE	44.731	44.742	46.293	51.340	42.664	40.706	41.216	43.672

	PARAMETRIC POINT		9	10	11	12	13	14	15	16
	TOTAL CAPITAL COST	,M$	263.93	250.31	234.13	220.87	157.03	284.21	148.29	221.80
P	PRESS HE FURNACE	,M$	57.340	30.000	43.390	46.350	23.540	37.570	22.980	23.360
L	PUMP UP GT-GEN	,M$	7.410	7.410	7.410	7.410	7.410	7.410	7.410	7.410
A	HELIUM GAS TURB-GEN	,M$	13.810	13.500	13.141	12.400	11.610	15.220	11.690	13.900
N	PUMP UP RECUPERATOR & PIPING		9.261	9.261	9.261	9.261	4.122	19.565	4.122	19.565
T	HELIUM RECUPERATOR & PIPING		17.920	14.210	8.910	6.450	5.860	33.420	3.920	21.030
R	TOT MAJOR COMPONENT COST	,M$	100.641	94.391	87.012	81.881	52.542	113.185	50.122	85.265
E	TOT MAJOR COMPONENT COST	,$/KWE	285.355	274.243	246.218	243.346	183.337	326.813	167.019	250.808
S	BALANCE OF PLANT COST	,$/KWE	51.226	48.918	48.157	48.259	57.046	53.860	53.975	51.545
U	SITE LABOR	,$/KWE	85.390	71.305	78.224	78.458	63.341	86.236	59.602	69.106
L	TOTAL DIRECT COST	,$/KWE	424.571	394.466	372.599	370.063	303.724	466.909	280.595	371.459
T	INDIRECT COSTS	,$/KWE	44.054	41.466	39.894	40.013	32.304	43.931	30.397	35.244
	PROF & OWNER COSTS	,$/KWE	33.969	31.557	29.802	29.605	24.215	37.353	22.443	29.717
B	CONTINGENCY COST	,$/KWE	32.545	30.297	28.585	29.244	22.732	35.744	21.160	29.381
R	ESCALATION COST	,$/KWE	101.648	94.865	89.575	88.179	69.889	110.661	65.384	87.763
E	INT DURING CONSTRUCTION	,$/KWE	115.776	109.127	102.046	100.322	73.194	125.997	74.150	99.876
A	TOTAL CAPITALIZATION	,$/KWE	752.561	700.759	662.507	656.426	531.051	820.644	494.145	652.441
K	COST OF ELEC-CAPITAL	,MILLS/KWE	23.790	22.154	20.943	20.751	16.783	25.942	15.621	20.625
D	COST OF ELEC-FUEL	,MILLS/KWE	23.770	23.335	23.588	24.774	28.936	24.065	27.782	24.522
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.549	.548	.548	.549	.548	.548	.548	.548
W	TOTAL COST OF ELEC	,MILLS/KWE	48.109	46.036	45.079	46.073	46.271	50.556	43.951	45.695
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	55.357	52.734	51.473	52.410	51.419	58.450	49.798	51.994
	COE 0.8 CAP. FACTOR	,MILLS/KWE	43.573	41.809	41.078	42.107	43.049	45.617	40.947	41.753
	COE 1.2XCAP. COST	,MILLS/KWE	52.866	50.467	49.268	50.223	49.629	55.744	47.075	49.820
	COE 1.2XFUEL COST	,MILLS/KWE	52.862	50.703	49.797	51.028	52.058	55.369	49.507	50.599
	COE (CONTINGENCY=0)	,MILLS/KWE	46.661	44.689	43.808	44.820	45.272	48.969	43.019	44.435
	COE (ESCALATION=0)	,MILLS/KWE	44.397	42.571	41.809	42.857	43.732	46.516	41.573	42.493

Table 7.17 - RECUPERATED HELIUM CLOSED CYCLE G T SYSTEMSUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT		17	18	19	20	21	22	23	24
	TOTAL CAPITAL COST	M$	145.81	213.21	140.92	135.02	257.80	253.05	235.32	223.34
P	PRESS HE FURNACE	M$	22.620	23.460	22.140	20.700	50.190	44.850	50.190	39.000
L	PUMP UP GT-GEN	M$	7.410	7.410	7.410	7.410	6.630	7.460	6.680	8.620
A	HELIUM GAS TURB-GEN	M$	11.540	13.030	11.050	11.720	16.040	15.200	12.860	14.590
N	PUMP UP RECUPERATOR & PIPING		4.122	19.565	4.122	19.565	7.722	7.722	.000	.000
T	HELIUM RECUPERATOR & PIPING		3.530	18.290	3.090	15.340	10.990	10.570	9.430	10.280
R	TOT MAJOR COMPONENT COST	M$	49.222	81.755	47.812	74.735	91.572	85.802	79.160	72.490
E	TOT MAJOR COMPONENT COST	$/KWE	164.292	249.967	167.718	251.001	272.638	259.875	278.026	227.154
S	BALANCE OF PLANT COST	$/KWE	52.991	51.583	53.245	53.062	78.290	78.072	84.396	79.490
U	SITE LABOR	$/KWE	58.983	70.130	60.403	71.414	99.465	95.565	107.781	89.268
L	TOTAL DIRECT COST	$/KWE	276.265	371.679	281.365	375.476	450.394	433.512	470.204	395.912
T	INDIRECT COSTS	$/KWE	30.081	35.766	30.805	36.421	50.727	48.738	54.968	45.527
	PROF & OWNER COSTS	$/KWE	22.101	29.734	22.509	30.038	36.032	34.681	37.616	31.673
B	CONTINGENCY COST	$/KWE	20.830	28.284	21.105	28.294	34.066	32.729	34.957	29.785
R	ESCALATION COST	$/KWE	64.392	87.249	64.963	86.584	105.894	101.558	107.379	92.323
E	INT DURING CONSTRUCTION	$/KWE	73.021	99.168	73.582	98.186	120.197	115.222	121.355	104.651
A	TOTAL CAPITALIZATION	$/KWE	486.691	651.900	494.330	654.999	797.309	766.440	826.479	699.871
K	COST OF ELEC-CAPITAL	MILLS/KWE	15.385	20.608	15.627	20.706	25.205	24.229	26.127	22.124
D	COST OF ELEC-FUEL	MILLS/KWE	27.825	25.487	29.239	27.998	8.378	8.521	9.880	8.814
O	COST OF ELEC-OP&MAIN	MILLS/KWE	.548	.548	.548	.548	1.849	1.871	2.082	1.917
W	TOTAL COST OF ELEC	MILLS/KWE	43.755	46.643	45.414	49.251	35.432	34.621	38.089	32.856
N	COE 0.5 CAP. FACTOR	MILLS/KWE	49.485	52.937	50.213	55.575	43.104	42.001	46.038	39.604
	COE 0.8 CAP. FACTOR	MILLS/KWE	40.793	42.704	42.409	45.294	30.631	30.003	33.115	28.633
	COE 1.2XCAP. COST	MILLS/KWE	46.835	50.765	48.539	53.393	40.473	39.466	43.314	37.281
	COE 1.2XFUEL COST	MILLS/KWE	49.323	51.740	51.262	54.851	37.107	36.325	40.065	34.618
	COE (CONTINGENCY=0)	MILLS/KWE	42.841	45.391	44.487	48.006	33.928	33.179	36.561	31.545
	COE (ESCALATION=0)	MILLS/KWE	41.417	43.463	43.054	46.103	31.578	30.926	34.196	29.500

	PARAMETRIC POINT		25	26	27	28	29	30	31	32
	TOTAL CAPITAL COST	M$	230.82	250.19	234.63	236.57	273.22	372.59	276.91	255.86
P	PRESS HE FURNACE	M$	44.350	43.120	41.530	42.790	58.120	46.970	53.880	52.830
L	PUMP UP GT-GEN	M$	7.460	6.790	6.790	6.790	6.790	6.790	6.790	6.790
A	HELIUM GAS TURB-GEN	M$	13.370	19.231	18.770	18.060	21.290	20.320	22.010	20.421
N	PUMP UP RECUPERATOR & PIPING		.000	.000	.000	.000	.000	.000	.000	.000
T	HELIUM RECUPERATOR & PIPING		9.940	12.200	12.030	11.760	12.930	12.600	19.600	12.630
R	TOT MAJOR COMPONENT COST	M$	75.120	81.341	79.120	79.400	99.130	86.680	102.280	92.671
E	TOT MAJOR COMPONENT COST	$/KWE	245.603	235.319	229.830	235.252	256.184	351.166	280.864	252.751
S	BALANCE OF PLANT COST	$/KWE	80.017	81.668	72.417	75.402	55.966	190.796	60.731	57.195
U	SITE LABOR	$/KWE	96.075	90.796	82.963	86.179	82.609	155.686	86.498	81.702
L	TOTAL DIRECT COST	$/KWE	421.694	407.783	385.211	396.833	394.758	697.648	428.092	391.648
T	INDIRECT COSTS	$/KWE	43.998	46.306	42.311	43.352	42.130	79.400	44.114	41.669
	PROF & OWNER COSTS	$/KWE	38.736	32.623	30.817	31.747	31.581	47.812	34.747	31.332
B	CONTINGENCY COST	$/KWE	31.627	30.940	29.214	30.039	30.587	45.529	32.957	30.173
R	ESCALATION COST	$/KWE	97.859	96.515	90.825	93.308	96.646	144.692	103.255	94.843
E	INT DURING CONSTRUCTION	$/KWE	110.840	109.640	103.169	105.934	110.385	164.538	117.736	108.165
A	TOTAL CAPITALIZATION	$/KWE	744.755	723.807	681.552	701.812	706.087	1179.619	760.901	697.828
K	COST OF ELEC-CAPITAL	MILLS/KWE	23.543	22.881	21.545	22.186	22.321	34.129	24.038	22.060
D	COST OF ELEC-FUEL	MILLS/KWE	9.076	8.702	8.812	8.949	27.547	9.410	26.738	26.555
O	COST OF ELEC-OP&MAIN	MILLS/KWE	1.957	1.899	.902	.940	.548	3.533	.548	.548
W	TOTAL COST OF ELEC	MILLS/KWE	34.577	33.483	31.260	32.075	50.416	47.072	51.324	49.163
N	COE 0.5 CAP. FACTOR	MILLS/KWE	41.751	40.458	37.835	38.842	57.223	57.423	59.647	55.892
	COE 0.8 CAP. FACTOR	MILLS/KWE	30.078	29.119	27.145	27.841	46.156	40.559	46.742	44.952
	COE 1.2XCAP. COST	MILLS/KWE	39.285	38.059	35.569	36.513	54.880	53.898	56.131	53.575
	COE 1.2XFUEL COST	MILLS/KWE	36.392	35.223	33.022	33.865	55.925	48.954	56.671	54.474
	COE (CONTINGENCY=0)	MILLS/KWE	33.198	32.115	29.969	30.749	49.049	45.055	49.855	47.817
	COE (ESCALATION=0)	MILLS/KWE	31.022	29.967	27.952	28.679	46.875	41.797	47.550	45.696

Table 7.17 - RECUPERATED HELIUM CLOSED CYCLE G T SYSTEMSUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT	33	34	35	36	37	38	39	40
PLANT	TOTAL CAPITAL COST ,M$	239.50	225.79	242.57	263.24	251.26	244.54	251.40	251.18
	PRESS HE FURNACE ,M$	49.160	46.840	49.740	54.430	51.120	50.940	51.010	51.010
	PUMP UP GT-GEN ,M$	6.790	6.790	6.790	6.790	6.790	6.790	6.790	6.790
	HELIUM GAS TURB-GEN ,M$	19.210	19.080	19.080	21.371	19.820	20.850	20.421	20.421
	PUMP UP RECUPERATOR & PIPING	.000	.000	.000	.000	.000	.000	.000	.000
	HELIUM RECUPERATOR & PIPING	11.130	9.470	12.150	12.950	12.680	12.590	12.630	12.630
RESULT BREAKDOWN	TOT MAJOR COMPONENT COST ,M$	86.290	82.180	87.760	95.541	90.410	91.170	90.851	90.851
	TOT MAJOR COMPONENT COST ,$/KWE	243.338	258.564	248.066	258.866	265.557	239.238	249.071	250.437
	BALANCE OF PLANT COST ,$/KWE	56.469	58.461	57.002	58.066	87.854	48.179	57.377	57.570
	SITE LABOR ,$/KWE	79.947	84.967	80.613	83.266	82.091	72.879	80.565	80.939
	TOTAL DIRECT COST ,$/KWE	379.754	401.992	385.680	400.199	435.502	360.296	387.013	388.947
	INDIRECT COSTS ,$/KWE	40.773	43.323	41.113	42.466	41.867	37.168	41.089	41.279
	PROF & OWNER COSTS ,$/KWE	30.390	32.159	30.854	32.016	34.840	28.824	30.961	31.116
	CONTINGENCY COST ,$/KWE	29.153	30.508	29.600	30.855	33.393	27.852	29.800	29.931
	ESCALATION COST ,$/KWE	91.428	94.756	92.747	97.027	103.687	87.576	93.608	93.971
	INT DURING CONSTRUCTION ,$/KWE	104.175	107.649	105.669	110.677	118.106	99.965	106.741	107.139
	TOTAL CAPITALIZATION ,$/KWE	675.664	710.398	695.663	713.239	767.395	641.681	689.210	692.383
	COST OF ELEC-CAPITAL ,MILLS/KWE	21.359	22.457	21.675	22.547	24.259	20.285	21.787	21.868
	COST OF ELEC-FUEL ,MILLS/KWE	27.453	30.637	27.526	26.396	28.601	25.552	26.650	26.795
	COST OF ELEC-OP&MAIN ,MILLS/KWE	.548	.548	.548	.548	.548	.548	.548	.548
	TOTAL COST OF ELEC ,MILLS/KWE	49.370	53.642	49.749	49.481	53.407	46.385	48.986	49.230
	COE 0.5 CAP. FACTOR ,MILLS/KWE	55.899	60.491	56.363	56.356	60.797	52.582	55.633	55.908
	COE 0.8 CAP. FACTOR ,MILLS/KWE	45.290	49.357	45.611	45.179	48.734	42.507	44.826	45.052
	COE 1.2XCAP. COST ,MILLS/KWE	53.642	58.134	54.085	53.990	58.259	50.442	53.343	53.608
	COE 1.2XFUEL COST ,MILLS/KWE	54.862	59.770	55.255	54.759	59.128	51.436	54.316	54.589
	COE (CONTINGENCY=0) ,MILLS/KWE	48.073	52.294	48.433	48.105	51.923	45.141	47.658	47.897
	COE (ESCALATION=0) ,MILLS/KWE	46.030	50.191	46.362	45.933	43.622	43.131	45.564	45.796

	PARAMETRIC POINT	41	42	43	44	45	46	47	48
PLANT	TOTAL CAPITAL COST ,M$	249.20	247.66	260.96	245.62	228.37	242.40	268.23	262.39
	PRESS HE FURNACE ,M$	51.260	51.490	57.280	53.530	49.680	51.010	51.010	55.490
	PUMP UP GT-GEN ,M$	6.790	6.790	6.790	6.790	6.790	6.790	6.790	.000
	HELIUM GAS TURB-GEN ,M$	20.150	19.830	19.620	18.670	17.140	17.355	24.330	21.780
	PUMP UP RECUPERATOR & PIPING	.000	.000	.000	.000	.000	.000	.000	7.650
	HELIUM RECUPERATOR & PIPING	11.930	11.500	11.050	9.670	8.940	10.910	16.070	13.430
RESULT BREAKDOWN	TOT MAJOR COMPONENT COST ,M$	90.130	89.650	94.740	88.660	82.550	86.066	98.200	98.350
	TOT MAJOR COMPONENT COST ,$/KWE	252.960	259.634	245.634	240.441	246.971	236.373	267.831	271.977
	BALANCE OF PLANT COST ,$/KWE	58.218	59.939	51.764	52.452	54.704	55.060	61.466	54.907
	SITE LABOR ,$/KWE	82.077	84.506	80.444	79.934	83.002	78.936	82.628	86.925
	TOTAL DIRECT COST ,$/KWE	393.255	404.079	377.842	372.826	384.677	370.368	411.925	413.808
	INDIRECT COSTS ,$/KWE	41.359	43.099	41.027	40.766	42.331	40.257	42.140	44.332
	PROF & OWNER COSTS ,$/KWE	31.460	[illegible]	30.231	29.826	30.774	29.629	32.954	33.105
	CONTINGENCY COST ,$/KWE	30.205	30.935	29.269	28.740	28.349	28.534	31.735	31.036
	ESCALATION COST ,$/KWE	94.699	96.775	92.591	90.599	91.741	89.853	99.430	95.345
	INT DURING CONSTRUCTION ,$/KWE	107.915	110.136	105.731	103.339	104.365	102.474	113.396	107.992
	TOTAL CAPITALIZATION ,$/KWE	699.394	717.303	676.731	666.095	682.237	661.115	731.580	725.617
	COST OF ELEC-CAPITAL ,MILLS/KWE	22.109	22.676	21.393	21.057	21.599	20.899	23.127	22.938
	COST OF ELEC-FUEL ,MILLS/KWE	27.328	28.205	25.250	26.405	29.126	26.555	26.555	27.296
	COST OF ELEC-OP&MAIN ,MILLS/KWE	.548	.548	.548	.548	.548	.548	.548	.548
	TOTAL COST OF ELEC ,MILLS/KWE	49.985	51.428	47.191	48.010	51.273	48.002	50.230	50.782
	COE 0.5 CAP. FACTOR ,MILLS/KWE	56.729	58.342	53.720	54.438	57.864	54.333	57.279	57.775
	COE 0.8 CAP. FACTOR ,MILLS/KWE	45.765	47.102	43.105	43.987	47.149	44.009	45.819	46.406
	COE 1.2XCAP. COST ,MILLS/KWE	54.407	55.964	51.470	52.221	55.593	52.132	54.355	55.370
	COE 1.2XFUEL COST ,MILLS/KWE	55.451	57.069	52.241	53.291	57.098	53.313	55.541	56.241
	COE (CONTINGENCY=0) ,MILLS/KWE	48.641	50.054	45.883	46.728	49.972	46.730	48.815	49.419
	COE (ESCALATION=0) ,MILLS/KWE	46.520	47.898	43.803	44.698	47.927	44.719	46.595	47.319

Table 7.18 COMBINED AIR-HELIUM-STEAM TURB CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT		1	2	3	4	5	6	7	8
	TOTAL CAPITAL COST	M$	146.24	134.31	123.24	158.00	168.44	170.33	217.15	217.22
P	PRESS HE FURNACE	M$	10.520	10.720	10.880	18.760	19.160	22.180	37.220	38.050
L	PUMP UP ST-GEN	M$	7.410	7.410	7.410	7.410	7.410	7.410	7.410	7.410
A	HELIUM GAS TURB-GEN	M$	4.920	6.080	7.250	5.880	6.700	7.370	6.480	7.110
N	STEAM TURBINE-GENERATOR	M$	9.445	7.137	5.029	9.483	7.910	7.200	8.645	8.209
T	PUMP UP REC VAP GEN	M$	3.260	1.820	1.450	3.540	3.220	2.070	4.640	3.990
	HE TURB REC VAP GEN	M$	10.100	7.920	4.360	9.260	8.500	8.290	6.950	6.770
R	TOT MAJOR COMPONENT COST	M$	44.655	41.087	37.379	52.333	52.900	54.520	71.345	71.539
E	TOT MAJOR COMPONENT COST	$/KWE	127.343	123.799	119.191	135.558	137.743	146.175	170.525	171.418
S	BALANCE OF PLANT COST	$/KWE	47.544	47.147	48.180	45.756	45.168	45.223	44.487	44.445
U	SITE LABOR	$/KWE	52.889	51.125	49.351	54.792	55.175	57.211	64.987	65.048
L	TOTAL DIRECT COST	$/KWE	227.776	222.060	216.723	236.106	238.087	248.610	279.999	280.911
T	INDIRECT COSTS	$/KWE	25.973	26.073	25.159	27.944	28.140	29.178	33.143	33.175
	PROF & OWNER COSTS	$/KWE	18.222	17.765	17.338	18.889	19.047	19.889	22.400	22.473
B	CONTINGENCY COST	$/KWE	19.045	17.495	16.959	18.901	19.047	19.823	22.611	22.677
R	ESCALATION COST	$/KWE	58.647	56.485	54.441	61.954	62.393	64.715	74.659	74.840
E	INT DURING CONSTRUCTION	$/KWE	67.379	54.789	62.342	71.376	71.869	74.478	86.217	86.418
A	TOTAL CAPITALIZATION	$/KWE	417.044	404.657	392.972	435.170	438.583	456.692	519.031	520.494
K	COST OF ELEC-CAPITAL	MILLS/KWE	13.184	12.792	12.423	13.757	13.865	14.437	16.408	16.454
D	COST OF ELEC-FUEL	MILLS/KWE	23.766	25.118	26.583	21.588	21.708	22.350	19.924	19.975
O	COST OF ELEC-OP&MAIN	MILLS/KWE	.614	.602	.596	.606	.602	.597	.603	.600
W	TOTAL COST OF ELEC	MILLS/KWE	37.563	38.512	39.602	35.951	36.175	37.384	36.935	37.029
N	COE 0.5 CAP. FACTOR	MILLS/KWE	41.630	42.461	43.440	40.189	40.446	41.826	41.969	42.076
	COE 0.8 CAP. FACTOR	MILLS/KWE	35.017	36.039	37.198	33.297	33.501	34.602	33.784	33.869
	COE 1.2XCAP. COST	MILLS/KWE	40.200	41.070	42.087	38.702	38.949	40.271	40.217	40.320
	COE 1.2XFUEL COST	MILLS/KWE	42.317	43.536	44.919	40.268	40.517	41.854	40.920	41.024
	COE (CONTINGENCY=0)	MILLS/KWE	36.746	37.723	38.939	35.089	35.307	36.483	35.899	35.990
	COE (ESCALATION=0)	MILLS/KWE	35.405	36.436	37.605	33.665	33.873	34.998	34.175	34.262

	PARAMETRIC POINT		9	10	11	12	13	14	15	16
	TOTAL CAPITAL COST	M$	217.52	131.24	171.93	240.13	166.29	171.71	170.86	172.66
P	PRESS HE FURNACE	M$	39.710	19.160	28.940	49.680	18.860	19.480	19.800	20.280
L	PUMP UP ST-GEN	M$	7.410	7.410	7.460	6.790	7.410	7.410	7.410	7.410
A	HELIUM GAS TURB-GEN	M$	8.090	6.700	8.580	11.130	6.670	6.760	6.990	7.310
N	STEAM TURBINE-GENERATOR	M$	7.337	4.646	6.141	7.710	7.710	8.134	7.411	7.486
T	PUMP UP REC VAP GEN	M$	2.900	.000	.000	.000	3.270	3.130	3.500	4.060
	HE TURB REC VAP GEN	M$	7.170	4.610	6.500	8.750	7.990	9.100	8.270	7.280
R	TOT MAJOR COMPONENT COST	M$	72.617	42.526	57.621	84.060	51.910	54.014	53.381	53.826
E	TOT MAJOR COMPONENT COST	$/KWE	179.155	144.462	159.930	221.053	135.830	139.755	137.153	137.195
S	BALANCE OF PLANT COST	$/KWE	44.372	46.487	45.508	45.504	45.798	45.728	45.672	46.021
U	SITE LABOR	$/KWE	66.884	56.097	62.259	77.394	54.696	55.668	55.226	55.287
L	TOTAL DIRECT COST	$/KWE	290.412	247.047	276.698	343.951	236.323	241.151	238.051	238.503
T	INDIRECT COSTS	$/KWE	34.111	28.613	31.752	39.471	27.895	28.391	28.165	28.197
	PROF & OWNER COSTS	$/KWE	23.233	19.764	22.136	27.516	18.906	19.292	19.044	19.080
B	CONTINGENCY COST	$/KWE	23.356	19.195	21.948	27.487	18.895	19.306	19.073	19.128
R	ESCALATION COST	$/KWE	76.862	61.229	70.595	89.716	61.859	63.257	62.565	62.790
E	INT DURING CONSTRUCTION	$/KWE	88.672	59.983	91.032	103.313	71.243	72.878	72.097	72.375
A	TOTAL CAPITALIZATION	$/KWE	536.656	445.827	504.061	631.454	435.122	444.275	438.995	440.072
K	COST OF ELEC-CAPITAL	MILLS/KWE	16.955	14.094	15.934	19.962	13.755	14.045	13.878	13.912
D	COST OF ELEC-FUEL	MILLS/KWE	20.566	28.318	26.653	25.606	21.808	21.569	21.418	21.249
O	COST OF ELEC-OP&MAIN	MILLS/KWE	.594	.584	.592	.601	.601	.604	.606	.609
W	TOTAL COST OF ELEC	MILLS/KWE	38.125	42.996	43.179	46.168	36.164	36.218	35.902	35.770
N	COE 0.5 CAP. FACTOR	MILLS/KWE	43.326	47.335	48.071	52.268	40.402	40.543	40.177	40.054
	COE 0.8 CAP. FACTOR	MILLS/KWE	34.870	40.278	40.117	42.351	33.510	33.510	33.225	33.086
	COE 1.2XCAP. COST	MILLS/KWE	41.518	45.814	46.365	50.161	38.915	39.027	38.677	38.552
	COE 1.2XFUEL COST	MILLS/KWE	42.239	48.659	48.510	51.290	40.525	40.532	40.186	40.019
	COE (CONTINGENCY=0)	MILLS/KWE	37.057	42.136	42.191	44.917	35.303	35.338	35.032	34.897
	COE (ESCALATION=0)	MILLS/KWE	35.286	40.753	40.583	42.859	33.882	33.884	33.593	33.452

corresponding summaries for the combined closed-cycle system parametric points are given in Table 7.18. For these tabulations, the "Total Major Component Cost" entries include pressurized furnace, pump-up gas turbine generator, helium gas turbine generator, pump-up recuperator and piping, and helium recuperator and piping for the recuperated cycles or pressurized furnace, pump-up gas turbine generator, helium gas turbine generator, bottoming turbine generator, pump-up set vapor generator, and helium set vapor generator for the closed-cycle systems.

The top line of each summary table, Total Capital Cost, represents the total capitalized cost for each plant and is made up of the following items: total direct major component material costs, balance of plant direct material costs, site labor costs, indirect costs, professional services and ownership costs, contingency costs, escalation costs, and interest during construction costs.

Also included for each parametric point are cost of electricity data including the capital, fuel, and operating and maintenance costs components.

7.6 Analysis of Overall Cost of Electricity

Cost of electricity (COE) values have been computed for each parametric point for both the recuperated closed-cycle and combined closed-cycle systems. Summaries for each of these systems, including both COE and capital cost, are given in Tables 7.19 and 7.20.

Also, for each parametric point, the effect on COE of variations in labor rate, contingency, escalation rate, interest during construction, fixed charge rate, fuel cost, and capacity factor were calculated. The results for the recuperated cycle Base Case A are shown in Table 7.21. Similar tabulations for Base Case B and the closed combined-cycle base case are given in Tables 7.22 and 7.23, respectively.

The COE vs installed capital costs are shown graphically in Figure 7.58 for the recuperated closed cycles and in Figure 7.59 for the

Table 7.18 COMBINED AIR-HELIUM-STEAM TURB CYCLE SUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT		17	18	19	20	21	22	23	24
	TOTAL CAPITAL COST	,M$	166.89	165.15	161.13	161.00	158.47	158.57	171.90	192.67
P	PRESS HE FURNACE	,M$	18.500	18.500	18.500	18.500	19.160	19.160	19.940	27.100
L	PUMP UP ST-GEN	,M$	7.410	7.410	7.410	7.410	7.410	7.410	8.600	6.680
A	HELIUM GAS TURB-GEN	,M$	6.880	7.020	6.470	6.470	6.630	6.520	6.590	7.780
N	STEAM TURBINE-GENERATOR	,M$	3.159	7.648	7.561	7.187	8.009	8.358	8.694	7.561
T	PUMP UP REC VAP GEN	,M$	3.500	3.660	4.240	4.540	2.170	1.990	2.600	2.960
	HE TURB REC VAP GEN	,M$	7.980	7.380	5.620	5.560	6.480	6.390	8.740	10.610
R	TOT MAJOR COMPONENT COST	,M$	52.429	51.618	49.801	49.667	49.859	49.828	55.164	62.691
E	TOT MAJOR COMPONENT COST	,$/KWE	138.020	135.885	131.102	130.750	136.110	135.523	146.433	162.970
S	BALANCE OF PLANT COST	,$/KWE	45.877	45.877	45.877	45.877	45.600	45.664	45.500	46.214
U	SITE LABOR	,$/KWE	54.951	54.529	53.449	53.560	54.122	53.886	56.538	62.770
L	TOTAL DIRECT COST	,$/KWE	238.848	236.292	230.428	230.187	235.832	235.073	248.471	271.954
T	INDIRECT COSTS	,$/KWE	28.025	27.810	27.259	27.315	27.602	27.482	28.834	32.013
	PROF & OWNER COSTS	,$/KWE	19.108	18.903	18.434	18.415	18.867	18.806	19.878	21.756
B	CONTINGENCY COST	,$/KWE	19.084	18.880	18.411	18.392	18.770	18.718	19.836	21.761
R	ESCALATION COST	,$/KWE	62.408	61.757	60.253	60.207	61.167	61.013	64.752	71.270
E	INT DURING CONSTRUCTION	,$/KWE	71.862	71.113	69.381	69.329	70.361	70.191	74.544	82.100
A	TOTAL CAPITALIZATION	,$/KWE	439.336	434.756	424.167	423.845	432.600	431.283	456.314	500.853
K	COST OF ELEC-CAPITAL	,MILLS/KWE	13.888	13.744	13.409	13.399	13.675	13.634	14.425	15.833
D	COST OF ELEC-FUEL	,MILLS/KWE	21.943	21.943	21.943	21.943	22.756	22.672	22.126	23.641
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.600	.600	.600	.600	.602	.605	.599	.605
W	TOTAL COST OF ELEC	,MILLS/KWE	36.431	36.286	35.951	35.941	37.034	36.910	37.150	40.079
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	40.709	40.521	40.085	40.072	41.248	41.112	41.589	44.940
	COE 0.8 CAP. FACTOR	,MILLS/KWE	33.752	33.635	33.363	33.354	34.395	34.279	34.371	37.035
	COE 1.2XCAP. COST	,MILLS/KWE	39.209	39.035	38.633	38.621	39.769	39.637	40.035	43.245
	COE 1.2XFUEL COST	,MILLS/KWE	40.820	40.675	40.340	40.330	41.585	41.445	41.575	44.807
	COE (CONTINGENCY=0)	,MILLS/KWE	35.552	35.427	35.113	35.104	36.181	36.050	36.248	39.087
	COE (ESCALATION=0)	,MILLS/KWE	34.129	34.009	33.729	33.721	34.780	34.662	34.762	37.449

	PARAMETRIC POINT		25	26	27	28	29	30	31	32
	TOTAL CAPITAL COST	,M$	193.30	159.37	154.80	168.74	159.74	169.83	169.41	168.94
P	PRESS HE FURNACE	,M$	28.980	19.160	19.160	19.160	19.160	19.160	19.160	19.160
L	PUMP UP ST-GEN	,M$	7.460	7.410	7.410	7.410	7.410	7.410	7.410	7.410
A	HELIUM GAS TURB-GEN	,M$	8.140	6.810	6.810	6.640	6.230	6.570	6.230	6.700
N	STEAM TURBINE-GENERATOR	,M$	7.551	7.561	7.561	7.362	8.109	8.009	8.109	7.872
T	PUMP UP REC VAP GEN	,M$	1.170	2.710	2.300	3.420	3.390	3.420	3.390	3.210
	HE TURB REC VAP GEN	,M$	10.200	5.830	5.140	8.780	9.010	8.780	9.010	8.520
R	TOT MAJOR COMPONENT COST	,M$	63.511	49.481	48.381	52.772	53.309	53.349	53.309	52.872
E	TOT MAJOR COMPONENT COST	,$/KWE	165.915	132.657	133.932	137.862	139.726	139.407	140.821	137.062
S	BALANCE OF PLANT COST	,$/KWE	45.716	46.183	46.214	45.856	45.945	45.861	46.093	45.656
U	SITE LABOR	,$/KWE	62.862	53.676	53.705	55.586	55.969	55.716	56.290	54.989
L	TOTAL DIRECT COST	,$/KWE	274.493	232.517	233.852	239.304	241.641	240.985	243.204	237.707
T	INDIRECT COSTS	,$/KWE	32.050	27.375	27.390	28.349	28.544	28.415	28.708	28.044
	PROF & OWNER COSTS	,$/KWE	21.959	18.601	18.708	19.144	19.331	19.279	19.456	19.017
B	CONTINGENCY COST	,$/KWE	21.952	18.542	18.592	19.138	19.318	19.272	19.427	19.026
R	ESCALATION COST	,$/KWE	71.810	60.553	60.474	62.686	63.242	63.096	63.548	62.337
E	INT DURING CONSTRUCTION	,$/KWE	82.709	69.690	69.532	72.200	72.934	72.672	73.170	71.814
A	TOTAL CAPITALIZATION	,$/KWE	504.983	427.278	428.537	440.822	444.911	443.718	447.512	437.945
K	COST OF ELEC-CAPITAL	,MILLS/KWE	15.964	13.507	13.547	13.935	14.065	14.027	14.147	13.844
D	COST OF ELEC-FUEL	,MILLS/KWE	23.754	22.350	23.073	21.776	21.791	21.776	21.850	21.608
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.602	.601	.599	.603	.605	.604	.605	.602
W	TOTAL COST OF ELEC	,MILLS/KWE	40.319	36.458	37.218	36.315	36.460	36.406	36.602	36.054
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	45.220	40.621	41.394	40.607	40.791	40.726	40.957	40.318
	COE 0.8 CAP. FACTOR	,MILLS/KWE	37.252	33.850	34.604	33.627	33.749	33.702	33.875	33.383
	COE 1.2XCAP. COST	,MILLS/KWE	43.512	39.159	39.928	39.102	39.273	39.212	39.431	38.823
	COE 1.2XFUEL COST	,MILLS/KWE	45.070	40.928	41.833	40.670	40.818	40.761	40.972	40.375
	COE (CONTINGENCY=0)	,MILLS/KWE	39.320	35.615	36.375	35.443	35.581	35.528	35.718	35.187
	COE (ESCALATION=0)	,MILLS/KWE	37.670	34.226	34.991	34.002	34.128	34.079	34.258	33.754

Table 7.18 COMBINED AIR-HELIUM-STEAM TURB CYCLE SUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT	33	34	35	36	37	38	39	40
	TOTAL CAPITAL COST ,M$	169.54	170.08	168.73	169.51	168.32	172.95	172.33	271.25
P	PRESS HE FURNACE ,M$	19.160	19.160	19.160	19.160	19.160	19.160	20.000	18.360
L	PUMP UP ST-GEN ,M$	7.410	7.410	7.410	7.410	7.410	7.410	7.410	7.410
A	HELIUM GAS TURB-GEN ,M$	6.700	6.700	6.700	6.700	6.700	6.700	6.240	6.430
N	STEAM TURBINE-GENERATOR ,M$	7.972	8.034	7.860	7.947	7.910	7.910	8.034	7.735
T	PUMP UP REC VAP GEN ,M$	3.400	3.480	3.270	3.350	3.220	3.220	3.480	3.330
	HE TURB REC VAP GEN ,M$	8.620	8.680	8.460	8.630	8.220	10.160	8.970	8.170
R	TOT MAJOR COMPONENT COST ,M$	53.262	53.464	52.860	53.197	52.620	54.560	54.734	51.435
E	TOT MAJOR COMPONENT COST,$/KWE	138.881	139.604	137.454	138.635	136.487	141.519	135.794	141.838
S	BALANCE OF PLANT COST ,$/KWE	45.839	45.912	45.715	45.813	45.695	45.695	42.886	144.361
U	SITE LABOR ,$/KWE	55.531	55.701	55.108	55.435	54.804	56.314	52.924	112.364
L	TOTAL DIRECT COST ,$/KWE	240.220	241.217	238.277	239.884	236.986	243.528	231.604	398.563
T	INDIRECT COSTS ,$/KWE	28.305	28.407	28.105	28.272	27.950	28.720	26.991	57.306
	PROF & OWNER COSTS ,$/KWE	19.218	19.297	19.062	19.191	18.959	19.482	18.528	31.885
B	CONTINGENCY COST ,$/KWE	19.215	19.292	19.065	19.189	18.967	19.490	18.626	31.827
R	ESCALATION COST ,$/KWE	62.938	63.159	62.447	62.837	62.139	63.854	61.202	106.179
E	INT DURING CONSTRUCTION ,$/KWE	72.471	72.746	71.934	72.379	71.585	73.561	70.598	122.245
A	TOTAL CAPITALIZATION ,$/KWE	442.347	444.119	438.889	441.752	436.587	448.636	427.549	748.005
K	COST OF ELEC-CAPITAL,MILLS/KWE	13.984	14.040	13.874	13.965	13.801	14.182	13.516	23.646
D	COST OF ELEC-FUEL ,MILLS/KWE	21.737	21.766	21.681	21.721	21.708	21.708	22.627	7.628
O	COST OF ELEC-OP&MAIN,MILLS/KWE	.603	.604	.602	.603	.602	.602	.601	1.845
W	TOTAL COST OF ELEC ,MILLS/KWE	36.324	36.409	36.157	36.288	36.112	36.492	36.744	33.119
N	COE 0.5 CAP. FACTOR ,MILLS/KWE	40.630	40.732	40.430	40.589	40.363	40.858	40.910	40.324
	COE 0.8 CAP. FACTOR ,MILLS/KWE	33.627	33.702	33.481	33.595	33.449	33.759	34.135	28.611
	COE 1.2XCAP. COST ,MILLS/KWE	39.120	39.217	38.932	39.081	38.872	39.329	39.447	37.848
	COE 1.2XFUEL COST ,MILLS/KWE	40.671	40.762	40.493	40.632	40.453	40.834	41.270	34.645
	COE (CONTINGENCY=0) ,MILLS/KWE	35.448	35.531	35.288	35.414	35.247	35.604	35.893	31.671
	COE (ESCALATION=0) ,MILLS/KWE	34.003	34.079	33.853	33.970	33.819	34.136	34.483	29.204

	PARAMETRIC POINT	41	42	43	44	45	46	47	48
	TOTAL CAPITAL COST ,M$	259.95	247.99	251.62	170.99	160.87	167.26	152.78	220.42
P	PRESS HE FURNACE ,M$	44.850	43.270	44.720	19.160	19.160	19.160	19.160	23.740
L	PUMP UP ST-GEN ,M$	7.460	7.460	7.460	7.410	7.410	7.410	7.410	7.410
A	HELIUM GAS TURB-GEN ,M$	8.400	7.890	7.560	6.700	6.700	6.700	6.700	12.880
N	STEAM TURBINE-GENERATOR ,M$	7.972	7.773	7.611	7.611	8.022	5.356	4.111	3.363
T	PUMP UP REC VAP GEN ,M$	1.200	1.360	1.520	3.220	3.220	6.040	6.800	5.600
	HE TURB REC VAP GEN ,M$	11.080	10.430	9.880	8.460	8.530	3.870	4.230	5.320
R	TOT MAJOR COMPONENT COST ,M$	80.962	78.183	78.751	52.561	53.042	48.536	48.411	58.313
E	TOT MAJOR COMPONENT COST,$/KWE	218.289	215.359	220.372	141.502	135.568	136.476	152.306	143.966
S	BALANCE OF PLANT COST ,$/KWE	71.237	67.501	70.527	54.964	34.847	63.674	45.769	91.015
U	SITE LABOR ,$/KWE	90.621	88.294	91.750	55.146	52.325	57.339	61.838	61.956
L	TOTAL DIRECT COST ,$/KWE	380.147	371.155	382.648	251.612	222.741	257.489	263.913	296.937
T	INDIRECT COSTS ,$/KWE	46.217	45.030	46.792	29.124	25.686	29.243	31.537	31.598
	PROF & OWNER COSTS ,$/KWE	30.412	29.692	30.612	20.129	17.819	20.599	21.113	23.755
B	CONTINGENCY COST ,$/KWE	30.327	29.541	30.410	20.072	17.841	20.445	20.710	23.905
R	ESCALATION COST ,$/KWE	99.376	96.589	99.380	65.265	58.576	66.310	66.817	77.993
E	INT DURING CONSTRUCTION ,$/KWE	114.394	111.105	114.270	75.120	67.495	76.227	76.571	89.992
A	TOTAL CAPITALIZATION ,$/KWE	700.863	683.112	704.111	460.322	411.158	470.312	480.662	544.180
K	COST OF ELEC-CAPITAL,MILLS/KWE	22.156	21.595	22.259	14.552	12.998	14.868	15.195	17.203
D	COST OF ELEC-FUEL ,MILLS/KWE	7.586	7.818	7.932	22.442	21.307	23.444	26.231	20.577
O	COST OF ELEC-OP&MAIN,MILLS/KWE	1.783	.919	.951	.556	.557	.613	.631	.602
W	TOTAL COST OF ELEC ,MILLS/KWE	31.525	30.332	31.141	37.550	34.862	38.924	42.057	38.382
N	COE 0.5 CAP. FACTOR ,MILLS/KWE	38.233	36.922	37.330	42.027	38.972	43.496	46.727	43.654
	COE 0.8 CAP. FACTOR ,MILLS/KWE	27.296	26.208	26.893	34.747	32.350	36.062	39.133	35.082
	COE 1.2XCAP. COST ,MILLS/KWE	35.956	34.651	35.593	40.451	37.461	41.898	45.096	41.823
	COE 1.2XFUEL COST ,MILLS/KWE	33.042	31.895	32.728	42.039	39.123	43.613	47.303	42.498
	COE (CONTINGENCY=0) ,MILLS/KWE	30.146	28.990	29.761	36.637	34.048	37.997	41.124	37.289
	COE (ESCALATION=0) ,MILLS/KWE	27.861	26.773	27.481	35.144	32.700	36.483	39.603	35.500

Table 7.18 . COMBINED AIR-HELIUM-STEAM TURB CYCLE SUMMARY FLANT RESULTS
Continued

	PARAMETRIC POINT		49	50	51	52	53	54	55	56
	TOTAL CAPITAL COST	,M$	304.75	225.55	226.89	172.25	.00	.00	.00	.00
P	PRESS HE FURNACE	,M$	51.210	23.740	23.740	19.160	.000	.000	.000	.000
L	PUMP UP ST-GEN	,M$	6.790	7.410	7.410	7.410	.000	.000	.000	.000
A	HELIUM GAS TURB-GEN	,M$	22.221	12.660	12.880	6.700	.000	.000	.000	.000
N	STEAM TURBINE-GENERATOR	,M$	3.612	3.239	3.353	6.726	.000	.000	.000	.000
T	PUMP UP REC VAP GEN	,M$	4.040	5.110	5.600	7.000	.000	.000	.000	.000
	HE TURB REC VAP GEN	,M$	9.350	4.950	5.320	4.990	.000	.000	.000	.000
R	TOT MAJOR COMPONENT COST	,M$	97.233	57.109	58.313	51.986	.000	.000	.000	.000
E	TOT MAJOR COMPONENT COST	,$/KWE	221.135	148.053	145.786	130.154	.000	.000	.000	.000
S	BALANCE OF PLANT COST	,$/KWE	75.802	111.724	105.923	51.087	.000	.000	.000	.000
U	SITE LABOR	,$/KWE	73.791	52.075	59.873	52.719	.000	.000	.000	.000
L	TOTAL DIRECT COST	,$/KWE	375.728	321.853	311.582	233.959	.000	.000	.000	.000
T	INDIRECT COSTS	,$/KWE	40.183	31.659	30.535	26.885	.000	.000	.000	.000
	PROF & OWNER COSTS	,$/KWE	30.058	25.748	24.927	18.717	.000	.000	.000	.000
B	CONTINGENCY COST	,$/KWE	30.531	25.818	25.095	18.809	.000	.000	.000	.000
R	ESCALATION COST	,$/KWE	100.420	83.450	81.300	61.710	.000	.000	.000	.000
E	INT DURING CONSTRUCTION	,$/KWE	115.162	96.195	93.808	71.177	.000	.000	.000	.000
A	TOTAL CAPITALIZATION	,$/KWE	693.083	584.724	567.236	431.259	.000	.000	.000	.000
K	COST OF ELEC-CAPITAL	,MILLS/KWE	21.910	19.484	17.932	13.633	.000	.000	.000	.000
D	COST OF ELEC-FUEL	,MILLS/KWE	22.150	21.610	20.843	20.875	.000	.000	.000	.000
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.612	.548	.548	.602	.000	.000	.000	.000
W	TOTAL COST OF ELEC	,MILLS/KWE	44.672	40.642	39.322	35.111	.000	.000	.000	.000
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	51.356	46.299	44.813	39.312	.000	.000	.000	.000
	COE 0.8 CAP. FACTOR	,MILLS/KWE	40.489	37.102	35.885	32.480	.000	.000	.000	.000
	COE 1.2XCAP. COST	,MILLS/KWE	49.054	44.339	42.908	37.837	.000	.000	.000	.000
	COE 1.2XFUEL COST	,MILLS/KWE	49.102	44.964	43.491	39.286	.000	.000	.000	.000
	COE (CONTINGENCY=0)	,MILLS/KWE	43.268	39.464	38.175	34.251	.000	.000	.000	.000
	COE (ESCALATION=0)	,MILLS/KWE	40.953	37.562	36.318	32.831	.000	.000	.000	.000

Table 7.19 - RECUPERATED HELIUM CLOSED CYCLE C T SYSTEM 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	.303	.297	.293	.247	.337	.346	.338	.312
OVERALL ENERGY EFF	.153	.150	.143	.125	.170	.175	.170	.158
CAP COST MILLION $	158.519	149.446	142.304	132.666	191.172	176.549	170.618	161.155
CAPITAL COST,$/KWE	556.962	534.805	535.164	571.065	590.932	542.938	537.866	549.021
COE CAPITAL	17.607	16.906	16.918	18.053	18.682	17.163	17.003	17.356
COE.FUEL	29.295	29.833	31.354	35.880	26.311	25.641	26.276	28.401
COE OP & MAIN	.548	.548	.548	.548	.548	.548	.548	.548
COST OF ELECTRIC	47.439	47.298	48.820	54.480	45.542	43.352	43.827	46.305
EST TIME OF CONST	4.500	4.486	4.447	4.345	4.601	4.605	4.585	4.524

PARAMETRIC POINT	9	10	11	12	13	14	15	16
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.373	.380	.376	.358	.307	.369	.319	.362
OVERALL ENERGY EFF	.188	.192	.190	.181	.155	.136	.161	.183
CAP COST MILLION $	263.929	250.308	234.126	220.874	153.027	284.214	148.292	221.805
CAPITAL COST,$/KWE	752.561	700.798	662.507	656.426	531.051	820.644	494.145	652.441
COE CAPITAL	23.790	22.154	20.943	20.751	16.788	25.942	15.621	20.625
COE FUEL	23.770	23.335	23.588	24.774	28.936	24.065	27.782	24.522
COE OP & MAIN	.548	.548	.548	.548	.548	.548	.548	.548
COST OF ELECTRIC	48.108	46.036	45.079	46.073	46.271	50.556	43.951	45.695
EST TIME OF CONST	4.666	4.681	4.672	4.632	4.509	4.655	4.541	4.640

PARAMETRIC POINT	17	18	19	20	21	22	23	24
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.319	.349	.303	.317	.346	.340	.294	.329
OVERALL ENERGY EFF	.161	.175	.153	.160	.346	.340	.294	.329
CAP COST MILLION $	145.810	213.213	140.921	195.025	267.755	255.053	235.316	223.344
CAPITAL COST,$/KWE	496.691	651.900	494.330	654.999	797.309	756.440	626.479	699.871
COE CAPITAL	15.385	20.609	15.627	20.705	25.205	24.229	26.177	22.124
COE FUEL	27.825	25.487	29.239	27.998	8.378	8.521	9.390	8.314
COE OP & MAIN	.548	.548	.548	.548	1.849	1.871	2.082	1.917
COST OF ELECTRIC	43.758	46.643	45.414	49.251	35.432	34.621	33.039	32.356
EST TIME OF CONST	4.540	4.610	4.501	4.535	4.563	4.550	4.434	4.523

PARAMETRIC POINT	25	26	27	28	29	30	31	32
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.320	.333	.329	.324	.322	.309	.332	.334
OVERALL ENERGY EFF	.320	.333	.329	.324	.217	.310	.167	.169
CAP COST MILLION $	230.823	250.193	234.627	226.865	273.219	372.527	276.909	255.859
CAPITAL COST,$/KWE	744.755	723.807	691.552	701.812	706.087	1079.619	760.401	697.828
COE CAPITAL	23.543	22.891	21.545	22.186	22.321	34.129	24.038	22.060
COE FUEL	9.076	8.702	8.812	8.949	27.547	9.410	26.738	26.555
COE OP & MAIN	1.957	1.899	.902	.940	.548	3.533	.548	.548
COST OF ELECTRIC	34.577	33.493	31.260	32.075	50.416	47.072	51.324	49.163
EST TIME OF CONST	4.500	4.587	4.594	4.570	4.748	4.618	4.699	4.704

PARAMETRIC POINT	33	34	35	36	37	38	39	40
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.323	.290	.322	.336	.310	.347	.333	.331
OVERALL ENERGY EFF	.163	.146	.163	.170	.156	.175	.168	.167
CAP COST MILLION $	239.597	225.787	242.572	263.238	261.263	244.535	251.396	251.175
CAPITAL COST,$/KWE	675.694	710.398	685.663	713.239	767.395	641.681	689.210	692.393
COE CAPITAL	21.359	22.457	21.675	22.547	24.259	20.285	21.787	21.888
COE FUEL	27.463	30.637	27.526	26.386	23.601	25.552	26.650	26.795
COE OP & MAIN	.548	.548	.548	.548	.548	.548	.548	.548
COST OF ELECTRIC	49.370	53.642	49.749	49.481	53.407	46.385	48.986	49.230
EST TIME OF CONST	4.677	4.589	4.675	4.710	4.668	4.730	4.700	4.695

Table 7.19 - RECUPERATED HELIUM CLOSED CYCLE C T SYSTEMSUMMARY PLANT RESULTS
Continued

PARAMETRIC POINT	41	42	43	44	45	46	47	48
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.325	.315	.351	.336	.305	.334	.334	.325
OVERALL ENERGY EFF	.164	.159	.177	.170	.154	.169	.169	.164
CAP COST MILLION $	249.195	247.681	260.959	245.615	226.372	242.398	268.234	262.392
CAPITAL COST,$/KWE	699.394	717.303	676.731	606.095	683.237	661.115	731.580	725.617
COE CAPITAL	22.109	22.676	21.393	21.057	21.599	20.899	23.127	22.939
COE FUEL	27.328	28.205	25.250	26.405	29.126	26.555	26.555	27.296
COE OP & MAIN	.548	.548	.548	.548	.548	.548	.548	.548
COST OF ELECTRIC	49.985	51.429	47.191	48.010	51.273	48.002	50.230	50.782
EST TIME OF CONST	4.681	4.656	4.745	4.709	4.630	4.704	4.704	4.500

PARAMETRIC POINT	49	50	51	52	53	54	55	56
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.000	.000	.000	.000	.000	.000	.000	.000
OVERALL ENERGY EFF	.000	.000	.000	.000	.000	.000	.000	.000
CAP COST MILLION $	.000	.000	.000	.000	.000	.000	.000	.000
CAPITAL COST,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COE CAPITAL	.000	.000	.000	.000	.000	.000	.000	.000
COE FUEL	.000	.000	.000	.000	.000	.000	.000	.000
COE OP & MAIN	.000	.000	.000	.000	.000	.000	.000	.000
COST OF ELECTRIC	.000	.000	.000	.000	.000	.000	.000	.000
EST TIME OF CONST	.000	.000	.000	.000	.000	.000	.000	.000

Table 7.20 COMBINED AIR-HELIUM-STEAM TURB 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	.373	.353	.334	.411	.409	.397	.445	.444
OVERALL ENERGY EFF	.188	.178	.168	.207	.206	.200	.225	.224
CAP COST MILLION $	146.244	134.312	123.237	167.998	168.436	170.335	217.153	217.220
CAPITAL COST,$/KWE	417.044	404.557	392.972	435.170	438.583	456.692	513.031	520.494
COE CAPITAL	13.184	12.792	12.423	13.757	13.865	14.437	16.408	16.454
COE FUEL	23.765	25.118	26.583	21.588	21.708	22.350	19.924	19.975
COE OP & MAIN	.614	.602	.596	.606	.602	.597	.603	.600
COST OF ELECTRIC	37.563	38.512	39.602	35.951	36.175	37.384	36.935	37.029
EST TIME OF CONST	4.923	4.874	4.825	5.005	5.000	4.974	5.076	5.073

PARAMETRIC POINT	9	10	11	12	13	14	15	16
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.431	.313	.333	.347	.407	.411	.414	.418
OVERALL ENERGY EFF	.219	.158	.168	.175	.205	.208	.209	.211
CAP COST MILLION $	217.521	131.240	171.931	240.125	166.291	171.708	170.862	172.655
CAPITAL COST,$/KWE	536.555	445.827	504.061	631.454	435.122	444.275	438.995	440.072
COE CAPITAL	16.965	14.094	15.934	19.962	13.755	14.045	13.878	13.912
COE FUEL	20.555	28.318	26.653	25.606	21.808	21.569	21.418	21.249
COE OP & MAIN	.594	.584	.592	.601	.601	.604	.606	.609
COST OF ELECTRIC	38.125	42.996	43.179	46.168	36.164	36.218	35.902	35.770
EST TIME OF CONST	5.046	4.770	4.896	4.991	4.996	5.006	5.012	5.020

PARAMETRIC POINT	17	18	19	20	21	22	23	24
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.404	.404	.404	.404	.390	.391	.401	.375
OVERALL ENERGY EFF	.204	.204	.204	.204	.197	.197	.202	.189
CAP COST MILLION $	166.887	165.148	161.125	161.003	158.468	158.571	171.903	192.667
CAPITAL COST,$/KWE	439.335	434.756	424.167	423.845	432.600	431.283	455.314	500.853
COE CAPITAL	13.888	13.744	13.409	13.399	13.675	13.634	14.425	15.833
COE FUEL	21.943	21.943	21.943	21.943	22.756	22.672	22.126	23.641
COE OP & MAIN	.600	.600	.600	.600	.602	.605	.599	.605
COST OF ELECTRIC	36.431	36.286	35.951	35.941	37.034	36.910	37.150	40.079
EST TIME OF CONST	4.990	4.990	4.990	4.990	4.959	4.963	4.983	5.002

PARAMETRIC POINT	25	26	27	28	29	30	31	32
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.374	.397	.385	.407	.407	.407	.406	.411
OVERALL ENERGY EFF	.189	.200	.194	.206	.205	.205	.205	.207
CAP COST MILLION $	193.303	159.374	154.802	168.740	169.745	169.805	169.409	168.939
CAPITAL COST,$/KWE	534.983	427.278	428.537	440.822	444.911	443.718	447.512	437.945
COE CAPITAL	15.964	13.507	13.547	13.935	14.065	14.027	14.147	13.844
COE FUEL	23.754	22.350	23.073	21.775	21.791	21.775	21.850	21.608
COE OP & MAIN	.602	.601	.599	.603	.605	.604	.605	.602
COST OF ELECTRIC	40.319	36.458	37.218	36.315	36.460	36.405	36.602	36.054
EST TIME OF CONST	4.997	4.974	4.946	4.997	4.995	4.997	4.988	5.004

PARAMETRIC POINT	33	34	35	36	37	38	39	40
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.408	.408	.409	.409	.409	.409	.392	.380
OVERALL ENERGY EFF	.205	.206	.206	.206	.206	.206	.264	.382
CAP COST MILLION $	169.643	170.084	168.781	169.509	168.317	172.962	172.332	271.252
CAPITAL COST,$/KWE	442.347	444.119	439.899	441.752	436.587	448.535	427.549	748.005
COE CAPITAL	13.984	14.040	13.874	13.965	13.801	14.182	13.516	23.646
COE FUEL	21.737	21.766	21.681	21.721	21.708	21.708	22.627	7.628
COE OP & MAIN	.603	.604	.602	.603	.602	.602	.601	1.845
COST OF ELECTRIC	36.324	36.409	36.157	36.288	36.112	36.492	36.744	33.119
EST TIME OF CONST	4.949	4.998	[illegible]	[illegible]	[illegible]	[illegible]	5.042	4.985

Table 7.20 COMBINED AIR-HELIUM-STEAM TURB CYCLE, SUMMARY PLANT RESULTS
Continued

PARAMETRIC POINT	41	42	43	44	45	46	47	48
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.382	.371	.366	.395	.416	.378	.338	.431
OVERALL ENERGY EFF	.392	.371	.366	.199	.210	.191	.171	.218
CAP COST MILLION $	259.946	247.992	251.617	170.985	160.868	167.261	152.779	220.419
CAPITAL COST,$/KWE	700.353	583.112	704.111	450.322	411.158	470.312	480.662	544.180
COE CAPITAL	22.156	21.595	22.259	14.552	12.998	14.868	15.195	17.203
COE FUEL	7.585	7.819	7.932	22.442	21.307	23.444	25.231	20.577
COE OP & MAIN	1.783	.919	.951	.556	.557	.613	.631	.602
COST OF ELECTRIC	31.525	30.332	31.141	37.550	34.862	38.924	42.057	38.382
EST TIME OF CONST	4.978	4.959	4.947	4.977	5.010	4.940	4.847	5.051

PARAMETRIC POINT	49	50	51	52	53	54	55	56
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.401	.411	.426	.425	.000	.000	.000	.000
OVERALL ENERGY EFF	.202	.207	.215	.214	.000	.000	.000	.000
CAP COST MILLION $	304.749	225.545	226.890	172.254	.000	.000	.000	.000
CAPITAL COST,$/KWE	593.083	584.724	567.236	431.259	.000	.000	.000	.000
COE CAPITAL	21.910	18.484	17.932	13.633	.000	.000	.000	.000
COE FUEL	22.150	21.510	20.843	20.875	.000	.000	.000	.000
COE OP & MAIN	.612	.548	.548	.602	.000	.000	.000	.000
COST OF ELECTRIC	44.672	40.542	39.322	35.111	.000	.000	.000	.000
EST TIME OF CONST	5.126	5.022	5.051	5.040	.000	.000	.000	.000

Table 7.21

RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.25

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	117774482.	124797253.	130696381.	143056458.	161315664.
INDIRECT COST,$	51.0	9595972.	12177485.	15186040.	21439680.	30801375.
PROF & OWNER COSTS,$	8.0	9421958.	9983780.	10455710.	11444517.	12905353.
CONTINGENCY COST,$	7.5	8833086.	9359794.	9802228.	10729234.	12098675.
SUB TOTAL,$	.0	144625399.	156318310.	166140358.	186719889.	217121464.
ESCALATION COST,$	6.5	26402047.	29536644.	30329705.	34085595.	39636546.
INTREST DURING CONST,$	10.0	29904244.	32321991.	34352899.	38609136.	44894250.
TOTAL CAPITALIZATION,$	.0	200931636.	217176947.	230822960.	259414618.	301652288.
COST OF ELEC-CAPITAL	18.0	20.49452	22.15149	23.54335	26.45963	30.78776
COST OF ELEC-FUEL	.0	9.07590	9.07590	9.07590	9.07590	9.07590
COST OF ELEC-OP & MAIN	.0	1.95742	1.95742	1.95742	1.95742	1.95742
TOTAL COST OF ELEC	.0	31.52783	33.18480	34.57666	37.49294	41.80107

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	7.50	5.00	20.00
TOTAL DIRECT COSTS,$	.0	130696381.	130696381.	130696381.	130696381.	130696381.
INDIRECT COST,$	51.0	15186040.	15186040.	15186040.	15186040.	15186040.
PROF & OWNER COSTS,$	8.0	10455710.	10455710.	10455710.	10455710.	10455710.
CONTINGENCY COST,$	20.0	-6534819.	0.	9802228.	6534819.	26139276.
SUB TOTAL,$	.0	149803312.	156338130.	166140358.	162872948.	182477406.
ESCALATION COST,$	6.5	27347300.	28540262.	30329705.	29733224.	33312110.
INTREST DURING CONST,$	10.0	30974883.	32326039.	34352899.	33677296.	37730916.
TOTAL CAPITALIZATION,$	.0	209125494.	217204460.	230822960.	226283466.	253520432.
COST OF ELEC-CAPITAL	18.0	21.22827	22.15430	23.54335	23.08033	25.85843
COST OF ELEC-FUEL	.0	9.07590	9.07590	9.07590	9.07590	9.07590
COST OF ELEC-OP & MAIN	.0	1.95742	1.95742	1.95742	1.95742	1.95742
TOTAL COST OF ELEC	.0	32.26158	33.18761	34.57666	34.11365	36.89175

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	130696381.	130696381.	130696381.	130696381.	130696381.
INDIRECT COST,$	51.0	15186040.	15186040.	15186040.	15186040.	15186040.
PROF & OWNER COSTS,$	8.0	10455710.	10455710.	10455710.	10455710.	10455710.
CONTINGENCY COST,$	7.5	9802228.	9802228.	9802228.	9802228.	9802228.
SUB TOTAL,$	.0	166140358.	166140358.	166140358.	166140358.	166140358.
ESCALATION COST,$	.0	22996818.	30329705.	37869230.	48249720.	0.
INTREST DURING CONST,$	10.0	33270500.	34352899.	35459359.	36972589.	29832467.
TOTAL CAPITALIZATION,$	.0	222407676.	230822960.	239468946.	251362666.	195972824.
COST OF ELEC-CAPITAL	18.0	22.68501	23.54335	24.42522	25.63835	19.98873
COST OF ELEC-FUEL	.0	9.07590	9.07590	9.07590	9.07590	9.07590
COST OF ELEC-OP & MAIN	.0	1.95742	1.95742	1.95742	1.95742	1.95742
TOTAL COST OF ELEC	.0	33.71833	34.57666	35.45853	36.67166	31.02204

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	130696381.	130696381.	130696381.	130696381.	130696381.
INDIRECT COST,$	51.0	15186040.	15186040.	15186040.	15186040.	15186040.
PROF & OWNER COSTS,$	8.0	10455710.	10455710.	10455710.	10455710.	10455710.
CONTINGENCY COST,$	7.5	9802228.	9802228.	9802228.	9802228.	9802228.
SUB TOTAL,$	.0	166140358.	166140358.	166140358.	166140358.	166140358.
ESCALATION COST,$	6.5	30329705.	30329705.	30329705.	30329705.	30329705.
INTREST DURING CONST,$	15.0	20199060.	27185826.	34352899.	43526259.	52941701.
TOTAL CAPITALIZATION,$	.0	216669122.	223655888.	230822960.	239996320.	249411762.
COST OF ELEC-CAPITAL	18.0	22.09663	22.81233	23.54335	24.47901	25.43936
COST OF ELEC-FUEL	.0	9.07590	9.07590	9.07590	9.07590	9.07590
COST OF ELEC-OP & MAIN	.0	1.95742	1.95742	1.95742	1.95742	1.95742
TOTAL COST OF ELEC	.0	33.12995	33.84564	34.57666	35.51232	36.47267

Table 7.21 Continued-

RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM COST OF ELECTRICITY,MILLS/KW.HR

PARAMETRIC POINT NO.25

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	130696381.	130696381.	130696381.	130696381.	130696381.
INDIRECT COST,$	51.0	15186040.	15186040.	15186040.	15186040.	15186040.
PROF & OWNER COSTS,$	8.0	10455710.	10455710.	10455710.	10455710.	10455710.
CONTINGENCY COST,$	7.5	9802228.	9802228.	9802228.	9802228.	9802228.
SUB TOTAL,$	.0	166140358.	166140358.	166140358.	166140358.	166140358.
ESCALATION COST,$	6.5	30329705.	30329705.	30329705.	30329705.	30329705.
INTREST DURING CONST,$	10.0	34352899.	34352899.	34352899.	34352899.	34352899.
TOTAL CAPITALIZATION,$	.0	230822960.	230822960.	230822960.	230822960.	230822960.
COST OF ELEC-CAPITAL	75.0	13.07964	18.83468	23.54335	28.25202	32.69910
COST OF ELEC-FUEL	.0	9.07590	9.07590	9.07590	9.07590	9.07590
COST OF ELEC-OP & MAIN	.0	1.95742	1.95742	1.95742	1.95742	1.95742
TOTAL COST OF ELEC	.0	24.11295	29.86799	34.57666	39.28533	43.73241

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	130696381.	130696381.	130696381.	130696381.	130696381.
INDIRECT COST,$	51.0	15186040.	15186040.	15186040.	15186040.	15186040.
PROF & OWNER COSTS,$	8.0	10455710.	10455710.	10455710.	10455710.	10455710.
CONTINGENCY COST,$	7.5	9802228.	9802228.	9802228.	9802228.	9802228.
SUB TOTAL,$	.0	166140358.	166140358.	166140358.	166140358.	166140358.
ESCALATION COST,$	6.5	30329705.	30329705.	30329705.	30329705.	30329705.
INTREST DURING CONST,$	10.0	34352899.	34352899.	34352899.	34352899.	34352899.
TOTAL CAPITALIZATION,$	.0	230822960.	230822960.	230822960.	230822960.	230822960.
COST OF ELEC-CAPITAL	18.0	23.54335	23.54335	23.54335	23.54335	23.54335
COST OF ELEC-FUEL	.0	5.33876	9.07590	16.01629	26.69381	10.89107
COST OF ELEC-OP & MAIN	.0	1.95742	1.95742	1.95742	1.95742	1.95742
TOTAL COST OF ELEC	.0	30.83953	34.57666	41.51705	52.19458	36.39184

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	130696381.	130696381.	130696381.	130696381.	130696381.
INDIRECT COST,$	51.0	15186040.	15186040.	15186040.	15186040.	15186040.
PROF & OWNER COSTS,$	8.0	10455710.	10455710.	10455710.	10455710.	10455710.
CONTINGENCY COST,$	7.5	9802228.	9802228.	9802228.	9802228.	9802228.
SUB TOTAL,$	.0	166140358.	166140358.	166140358.	166140358.	166140358.
ESCALATION COST,$	6.5	30329705.	30329705.	30329705.	30329705.	30329705.
INTREST DURING CONST,$	10.0	34352899.	34352899.	34352899.	34352899.	34352899.
TOTAL CAPITALIZATION,$	.0	230822960.	230822960.	230822960.	230822960.	230822960.
COST OF ELEC-CAPITAL	18.0	127.52648	34.00706	30.60636	23.54335	19.12897
COST OF ELEC-FUEL	.0	9.07590	9.07590	9.07590	9.07590	9.07590
COST OF ELEC-OP & MAIN	.0	3.21250	2.11957	2.06874	1.95742	1.88281
TOTAL COST OF ELEC	.0	139.81489	45.20253	41.75099	34.57666	30.08767

Table 7.22

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RECUPEPATED HELIUM CLOSED CYCLE G T SYSTEM COST OF ELECTRICITY,MILLS/KW.HR
                    PARAMETRIC POINT NO.49

ACCOUNT                   RATE,               LABOR RATE, $/HR
                          PERCENT    6.00       9.50       10.60       15.00       21.50
 TOTAL DIRECT COSTS,$        .0  133397193. 143410653. 149637972. 152685678. 181950700.
 INDIRECT COST,$           51.0    8074697.  12854956.  16030887.  22665217.  32515478.
 PROF & OWNER COSTS,$       8.0   10373775.  11472853.  11971038.  13014954.  14556356.
 CONTINGENCY COST,$         7.5   10199789.  10755799.  11222848.  12201426.  13647052.
 SUB TOTAL,$                 .0  165150936. 178494264. 188862740. 210587172. 242690086.
 ESCALATION COST,$          6.5   30331618.  32584966.  34477782.  36443680.  44302392.
 INTREST DURING CONST,$    10.0   34355066.  36307320.  39051214.  43543182.  50179045.
 TOTAL CAPITALIZATION,$      .0  230837618. 247386550. 262391736. 292574032. 337161520.
 COST OF ELEC-CAPITAL      18.0    20.17993   21.67905   22.93836   25.57690   29.47475
 COST OF ELEC-FUEL           .0    27.29565   27.29565   27.29565   27.29565   27.29565
 COST OF ELEC-OP & MAIN      .0      .54790     .54790     .54790     .54790     .54790
 TOTAL COST OF ELEC          .0    48.02343   49.52260   50.78191   53.42045   57.31830

ACCOUNT                   RATE,               CONTINGENCY, PERCENT
                          PERCENT   -5.00        .00        7.50        5.00       20.00
 TOTAL DIRECT COSTS,$        .0  149637972. 149637972. 149637972. 149637972. 149637972.
 INDIRECT COST,$           51.0   16030887.  16030887.  16030887.  16030887.  16030887.
 PROF & OWNER COSTS,$       8.0   11971038.  11971038.  11971038.  11971038.  11971038.
 CONTINGENCY COST,$        20.0   -7481399.         0.  11222848.   7481899.  29927594.
 SUB TOTAL,$                 .0  170157996. 177639895. 188862740. 185121792. 207567498.
 ESCALATION COST,$          6.5   31063143.  32428999.  34477782.  33794855.  37392422.
 INTREST DURING CONST,$    10.0   35183627.  36730662.  39051214.  38277697.  42918801.
 TOTAL CAPITALIZATION,$      .0  236404764. 246799554. 262391736. 257194342. 288378708.
 COST OF ELEC-CAPITAL      18.0    20.66657   21.57528   22.93836   22.48400   25.21014
 COST OF ELEC-FUEL           .0    27.29565   27.29565   27.29565   27.29565   27.29565
 COST OF ELEC-OP & MAIN      .0      .54790     .54790     .54790     .54790     .54790
 TOTAL COST OF ELEC          .0    48.51012   49.41883   50.78191   50.32755   53.05369

ACCOUNT                   RATE,               ESCALATION RATE, PERCENT
                          PERCENT    5.00       6.50        8.00       10.00         .00
 TOTAL DIRECT COSTS,$        .0  149637972. 149637972. 149637972. 149637972. 149637972.
 INDIRECT COST,$           51.0   16030887.  16030887.  16030887.  16030887.  16030887.
 PROF & OWNER COSTS,$       8.0   11971038.  11971038.  11971038.  11971038.  11971038.
 CONTINGENCY COST,$         7.5   11222848.  11222848.  11222848.  11222848.  11222848.
 SUB TOTAL,$                 .0  188862740. 188862740. 188862740. 188862740. 188862740.
 ESCALATION COST,$           .0   26142005.  34477792.  43048460.  54848650.         0.
 INTREST DURING CONST,$    10.0   37820779.  39051214.  40309000.  42029189.  33912540.
 TOTAL CAPITALIZATION,$      .0  252825522. 262391736. 272220200. 285740576. 222775280.
 COST OF ELEC-CAPITAL      18.0    22.10203   22.93835   23.79756   24.97952   19.47503
 COST OF ELEC-FUEL           .0    27.29565   27.29565   27.29565   27.29565   27.29565
 COST OF ELEC-OP & MAIN      .0      .54790     .54790     .54790     .54790     .54790
 TOTAL COST OF ELEC          .0    49.94562   50.78191   51.64111   52.82307   47.31862

ACCOUNT                   RATE,               INT DURING CONST,PERCENT
                          PERCENT    6.00       8.00       10.00       12.50       15.00
 TOTAL DIRECT COSTS,$        .0  149637972. 149637972. 149637972. 149637972. 149637972.
 INDIRECT COST,$           51.0   16030887.  16030887.  16030887.  16030887.  16030887.
 PROF & OWNER COSTS,$       8.0   11971038.  11971038.  11971038.  11971038.  11971038.
 CONTINGENCY COST,$         7.5   11222848.  11222848.  11222848.  11222848.  11222848.
 SUB TOTAL,$                 .0  188862740. 188862740. 188862740. 188862740. 188862740.
 ESCALATION COST,$          6.5   34477782.  34477782.  34477782.  34477782.  34477782.
 INTREST DURING CONST,$    15.0   22927505.  30903927.  39051214.  49479178.  60182335.
 TOTAL CAPITALIZATION,$      .0  246263026. 254244448. 262391736. 272819700. 283522856.
 COST OF ELEC-CAPITAL      18.0    21.52882   22.22612   22.93836   23.84997   24.78565
 COST OF ELEC-FUEL           .0    27.29565   27.29565   27.29565   27.29565   27.29565
 COST OF ELEC-OP & MAIN      .0      .54790     .54790     .54790     .54790     .54790
 TOTAL COST OF ELEC          .0    49.37237   50.06967   50.78191   51.69352   52.62919
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Table 7.22 continued

RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.48

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	149637972.	149637972.	149637972.	149637972.	149637972.
INDIRECT COST,$	51.0	16030887.	16030887.	16030887.	16030887.	16030887.
PROF & OWNER COSTS,$	8.0	11971038.	11971038.	11971038.	11971038.	11971038.
CONTINGENCY COST,$	7.5	11222848.	11222848.	11222848.	11222848.	11222848.
SUB TOTAL,$	.0	188862740.	188862740.	188862740.	188862740.	188862740.
ESCALATION COST,$	6.5	34477782.	34477782.	34477782.	34477782.	34477782.
INTREST DURING CONST,$	10.0	39051214.	39051214.	39051214.	39051214.	39051214.
TOTAL CAPITALIZATION,$	.0	262391736.	262391736.	262391736.	262391736.	262391736.
COST OF ELEC-CAPITAL	18.0	12.74353	18.35069	22.93836	27.52603	31.85883
COST OF ELEC-FUEL	.0	27.29565	27.29565	27.29565	27.29565	27.29565
COST OF ELEC-OP & MAIN	.0	.54790	.54790	.54790	.54790	.54790
TOTAL COST OF ELEC	.0	40.58708	46.19423	50.78191	55.36958	59.70238

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU 1.50	2.60	4.00	2.08	3.12
TOTAL DIRECT COSTS,$	.0	149637972.	149637972.	149637972.	149637972.	149637972.
INDIRECT COST,$	51.0	16030887.	16030887.	16030887.	16030887.	16030887.
PROF & OWNER COSTS,$	8.0	11971038.	11971038.	11971038.	11971038.	11971038.
CONTINGENCY COST,$	7.5	11222848.	11222848.	11222848.	11222848.	11222848.
SUB TOTAL,$	.0	188862740.	188862740.	188862740.	188862740.	188862740.
ESCALATION COST,$	6.5	34477782.	34477782.	34477782.	34477782.	34477782.
INTREST DURING CONST,$	10.0	39051214.	39051214.	39051214.	39051214.	39051214.
TOTAL CAPITALIZATION,$	.0	262391736.	262391736.	262391736.	262391736.	262391736.
COST OF ELEC-CAPITAL	18.0	22.93836	22.93836	22.93836	22.93836	22.93836
COST OF ELEC-FUEL	.0	15.74749	27.29565	41.99331	21.83652	32.75478
COST OF ELEC-OP & MAIN	.0	.54790	.54790	.54790	.54790	.54790
TOTAL COST OF ELEC	.0	39.23375	50.78191	65.47956	45.32278	56.24104

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	149637972.	149637972.	149637972.	149637972.	149637972.
INDIRECT COST,$	51.0	16030887.	16030887.	16030887.	16030887.	16030887.
PROF & OWNER COSTS,$	8.0	11971038.	11971038.	11971038.	11971038.	11971038.
CONTINGENCY COST,$	7.5	11222848.	11222848.	11222848.	11222848.	11222848.
SUB TOTAL,$	.0	188862740.	188862740.	188862740.	188862740.	188862740.
ESCALATION COST,$	6.5	34477782.	34477782.	34477782.	34477782.	34477782.
INTREST DURING CONST,$	10.0	39051214.	39051214.	39051214.	39051214.	39051214.
TOTAL CAPITALIZATION,$	.0	262391736.	262391736.	262391736.	262391736.	262391736.
COST OF ELEC-CAPITAL	18.0	124.24943	33.13319	29.81986	22.93836	18.63741
COST OF ELEC-FUEL	.0	27.29565	27.29565	27.29565	27.29565	27.29565
COST OF ELEC-OP & MAIN	.0	1.90300	.71006	.65922	.54790	.47329
TOTAL COST OF ELEC	.0	153.34808	61.13889	57.77474	50.78191	46.40635

Table 7.23 - COMBINED AIR-HELIUM-STEAM TURB CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO. 5.

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	82240635.	87238343.	91436418.	100232383.	113226424.
INDIRECT COST,$	51.0	6117194.	8666025.	10807043.	15292986.	21919946.
PROF & OWNER COSTS,$	8.0	6579251.	6979067.	7314913.	8018591.	9058114.
CONTINGENCY COST,$	8.0	6579251.	6979067.	7314913.	8018591.	9058114.
SUB TOTAL,$	.0	101516329.	109862502.	116873287.	131562548.	153262594.
ESCALATION COST,$	6.5	20813097.	22524248.	23961614.	26973238.	31422229.
INTREST DURING CONST,$	10.0	23974170.	25945208.	27600880.	31069907.	36194605.
TOTAL CAPITALIZATION,$	.0	146303596.	158331958.	168435780.	189605692.	220879426.
COST OF ELEC-CAPITAL	18.0	12.04280	13.03290	13.86458	15.60716	18.18142
COST OF ELEC-FUEL	.0	21.70837	21.70837	21.70837	21.70837	21.70837
COST OF ELEC-OP & MAIN	.0	.60225	.60225	.60225	.60225	.60225
TOTAL COST OF ELEC	.0	34.35342	35.34352	36.17520	37.91778	40.49204

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	8.00	5.00	20.00
TOTAL DIRECT COSTS,$	.0	91436418.	91436418.	91436418.	91436418.	91436418.
INDIRECT COST,$	51.0	10807043.	10807043.	10807043.	10807043.	10807043.
PROF & OWNER COSTS,$	8.0	7314913.	7314913.	7314913.	7314913.	7314913.
CONTINGENCY COST,$	20.0	-4571821.	0.	7314913.	4571821.	18287283.
SUB TOTAL,$	.0	104986554.	109558374.	116873287.	114130194.	127845657.
ESCALATION COST,$	6.5	21524570.	22461895.	23961614.	23399219.	26211193.
INTREST DURING CONST,$	10.0	24793701.	25873385.	27600880.	26953070.	30192123.
TOTAL CAPITALIZATION,$	.0	151304824.	157893654.	168435780.	164482480.	184248972.
COST OF ELEC-CAPITAL	18.0	12.45447	12.99682	13.86458	13.53917	15.16623
COST OF ELEC-FUEL	.0	21.70837	21.70837	21.70837	21.70837	21.70837
COST OF ELEC-OP & MAIN	.0	.60225	.60225	.60225	.60225	.60225
TOTAL COST OF ELEC	.0	34.76509	35.30744	36.17520	35.84979	37.47685

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	91436418.	91436418.	91436418.	91436418.	91436418.
INDIRECT COST,$	51.0	10807043.	10807043.	10807043.	10807043.	10807043.
PROF & OWNER COSTS,$	8.0	7314913.	7314913.	7314913.	7314913.	7314913.
CONTINGENCY COST,$	8.0	7314913.	7314913.	7314913.	7314913.	7314913.
SUB TOTAL,$	.0	116873287.	116873287.	116873287.	116873287.	116873287.
ESCALATION COST,$	.0	18123232.	23961614.	29992857.	38342171.	0.
INTREST DURING CONST,$	10.0	25536159.	27600880.	29591014.	29951471.	23598606.
TOTAL CAPITALIZATION,$	.0	161632676.	168435780.	175457158.	185166928.	140471892.
COST OF ELEC-CAPITAL	18.0	13.30459	13.86458	14.44254	15.24179	11.56277
COST OF ELEC-FUEL	.0	21.70837	21.70837	21.70837	21.70837	21.70837
COST OF ELEC-OP & MAIN	.0	.60225	.60225	.60225	.60225	.60225
TOTAL COST OF ELEC	.0	35.61522	36.17520	36.75316	37.55241	33.87339

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	91436418.	91436418.	91436418.	91436418.	91436418.
INDIRECT COST,$	51.0	10807043.	10807043.	10807043.	10807043.	10807043.
PROF & OWNER COSTS,$	8.0	7314913.	7314913.	7314913.	7314913.	7314913.
CONTINGENCY COST,$	8.0	7314913.	7314913.	7314913.	7314913.	7314913.
SUB TOTAL,$	.0	116873287.	116873287.	116873287.	116873287.	116873287.
ESCALATION COST,$	6.5	23961614.	23961614.	23961614.	23961614.	23961614.
INTREST DURING CONST,$	15.0	16130300.	21792102.	27600880.	35072679.	42783719.
TOTAL CAPITALIZATION,$	.0	156965198.	162627002.	168435780.	175907578.	183618618.
COST OF ELEC-CAPITAL	18.0	12.92040	13.38644	13.86458	14.47961	15.11434
COST OF ELEC-FUEL	.0	21.70837	21.70837	21.70837	21.70837	21.70837
COST OF ELEC-OP & MAIN	.0	.60225	.60225	.60225	.60225	.60225
TOTAL COST OF ELEC	.0	35.23102	35.69706	36.17520	36.79024	37.42496

Table 7.23 - COMBINED AIR-HELIUM-STEAM TURB CYCLE   COST OF ELECTRICITY,MILLS/KW.HR
Continued

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                                       PARAMETRIC POINT NO. 5

ACCOUNT                      RATE,               FIXED CHARGE RATE, PCT
                           PERCENT   10.00      14.40      18.00        21.60      25.00
 TOTAL DIRECT COSTS,$          .0   91436418.  91436418.  91436418.   91436418.  91436418.
 INDIRECT COST,$             51.0   10807043.  10807043.  10807043.   10807043.  10807043.
 PROF & OWNER COSTS,$         8.0    7314913.   7314913.   7314913.    7314913.   7314913.
 CONTINGENCY COST,$           8.0    7314913.   7314913.   7314913.    7314913.   7314913.
 SUB TOTAL,$                   .0  116873287. 116873287. 116873287.  116873287. 116873287.
 ESCALATION COST,$            6.5   23961614.  23961614.  23961614.   23961614.  23961614.
 INTREST DURING CONST,$      10.0   27600880.  27600880.  27600880.   27600880.  27600880.
 TOTAL CAPITALIZATION,$        .0  168435780. 168435780. 168435780.  168435780. 168435780.
 COST OF ELEC-CAPITAL        25.0     7.70255   11.09167   13.86458    16.63750   19.25636
 COST OF ELEC-FUEL             .0    21.70837   21.70837   21.70837    21.70837   21.70837
 COST OF ELEC-OP & MAIN        .0      .60225     .60225     .60225      .60225     .60225
 TOTAL COST OF ELEC            .0    30.01317   33.40229   36.17520    38.94812   41.56699

ACCOUNT                      RATE,               FUEL COST, $/10**6 BTU
                           PERCENT    1.50       2.60       4.00         2.08       3.12
 TOTAL DIRECT COSTS,$          .0   91436418.  91436418.  91436418.   91436418.  91436418.
 INDIRECT COST,$             51.0   10807043.  10807043.  10807043.   10807043.  10807043.
 PROF & OWNER COSTS,$         8.0    7314913.   7314913.   7314913.    7314913.   7314913.
 CONTINGENCY COST,$           8.0    7314913.   7314913.   7314913.    7314913.   7314913.
 SUB TOTAL,$                   .0  116873287. 116873287. 116873287.  116873287. 116873287.
 ESCALATION COST,$            6.5   23961614.  23961614.  23961614.   23961614.  23961614.
 INTREST DURING CONST,$      10.0   27600880.  27600880.  27600880.   27600880.  27600880.
 TOTAL CAPITALIZATION,$        .0  168435780. 168435780. 168435780.  168435780. 168435780.
 COST OF ELEC-CAPITAL        18.0    13.86458   13.86458   13.86458    13.86458   13.86458
 COST OF ELEC-FUEL             .0    12.52406   21.70837   33.39749    17.36670   26.05005
 COST OF ELEC-OP & MAIN        .0      .60225     .60225     .60225      .60225     .60225
 TOTAL COST OF ELEC            .0    26.99089   36.17520   47.86433    31.83353   40.51688

ACCOUNT                      RATE,               CAPACITY FACTOR, PERCENT
                           PERCENT   12.00      45.00      50.00        65.00      80.00
 TOTAL DIRECT COSTS,$          .0   91436418.  91436418.  91436418.   91436418.  91436418.
 INDIRECT COST,$             51.0   10807043.  10807043.  10807043.   10807043.  10807043.
 PROF & OWNER COSTS,$         8.0    7314913.   7314913.   7314913.    7314913.   7314913.
 CONTINGENCY COST,$           8.0    7314913.   7314913.   7314913.    7314913.   7314913.
 SUB TOTAL,$                   .0  116873287. 116873287. 116873287.  116873287. 116873287.
 ESCALATION COST,$            6.5   23961614.  23961614.  23961614.   23961614.  23961614.
 INTREST DURING CONST,$      10.0   27600880.  27600880.  27600880.   27600880.  27600880.
 TOTAL CAPITALIZATION,$        .0  168435780. 168435780. 168435780.  168435780. 168435780.
 COST OF ELEC-CAPITAL        18.0    75.09982   20.02661   18.02396    13.86458   11.26497
 COST OF ELEC-FUEL             .0    21.70837   21.70837   21.70837    21.70837   21.70837
 COST OF ELEC-OP & MAIN        .0     1.85732     .76441     .71357      .60225     .52764
 TOTAL COST OF ELEC            .0    98.66551   42.49939   40.44590    36.17520   33.50098
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combined closed cycles. Each plotted point is numbered according to the parametric point number established in Subsection 7.4.

The COE for the closed-cycle recuperated and closed-cycle combined systems did not compare favorably with conventional steam power plant COE. For no parametric point did the COE fall below 8.2 mills/MJ (30 mills/kWh). In general, both the capitalization and COE were higher for the recuperative systems.

One of the prominent aspects of Figures 7.58 and 7.59 is the great difference in COE and capitalization between distillate and coal fuels. Distillate at the price contemplated would not be competitive with the direct burning of coal for the base-load operation (65% capacity factor) illustrated in the figures.

Various relative effects can be discerned using these two figures. Related points have been connected by lines to assist in the interpretation. Thus, for the recuperated cycles, R1, R2, R3, R4 represents the points on distillate fuel having a pump-up turbine inlet temperature of 1478°K (2200°F) and a helium turbine inlet temperature of 922°K (1200°F). The individual points have different helium cycle pressure ratios of 2, 2.5, 3, and 4 to 1, respectively. The sequences R1, R2, R3, R4; R5, R6, R7, R8; and R9, R10, R11, R12 pertain to helium turbine inlet temperatures of 922°K (1200°F); 1089°K (1500°F) and 1255°K (1800°F), respectively. They clearly reflect the much greater costs associated with the higher temperature heat exchangers. The sequences R13, R15, R17, R19; R5, R6, R7, R8; and R14, R16, R18, R20 depict recuperator effectiveness values of 0.8, 0.9, and 0.95 applied to both the pump-up and helium cycles.

The above mentioned points can be considered to relate to parametric Point R6 as a mean value in the parameter variations. Point R6 is also the most attractive from the standpoint of lowest COE in the family of points.

The next group of points are those in the coal-burning family and relate to Point R25, Base Case A. Points R24, R25, R23 have changing

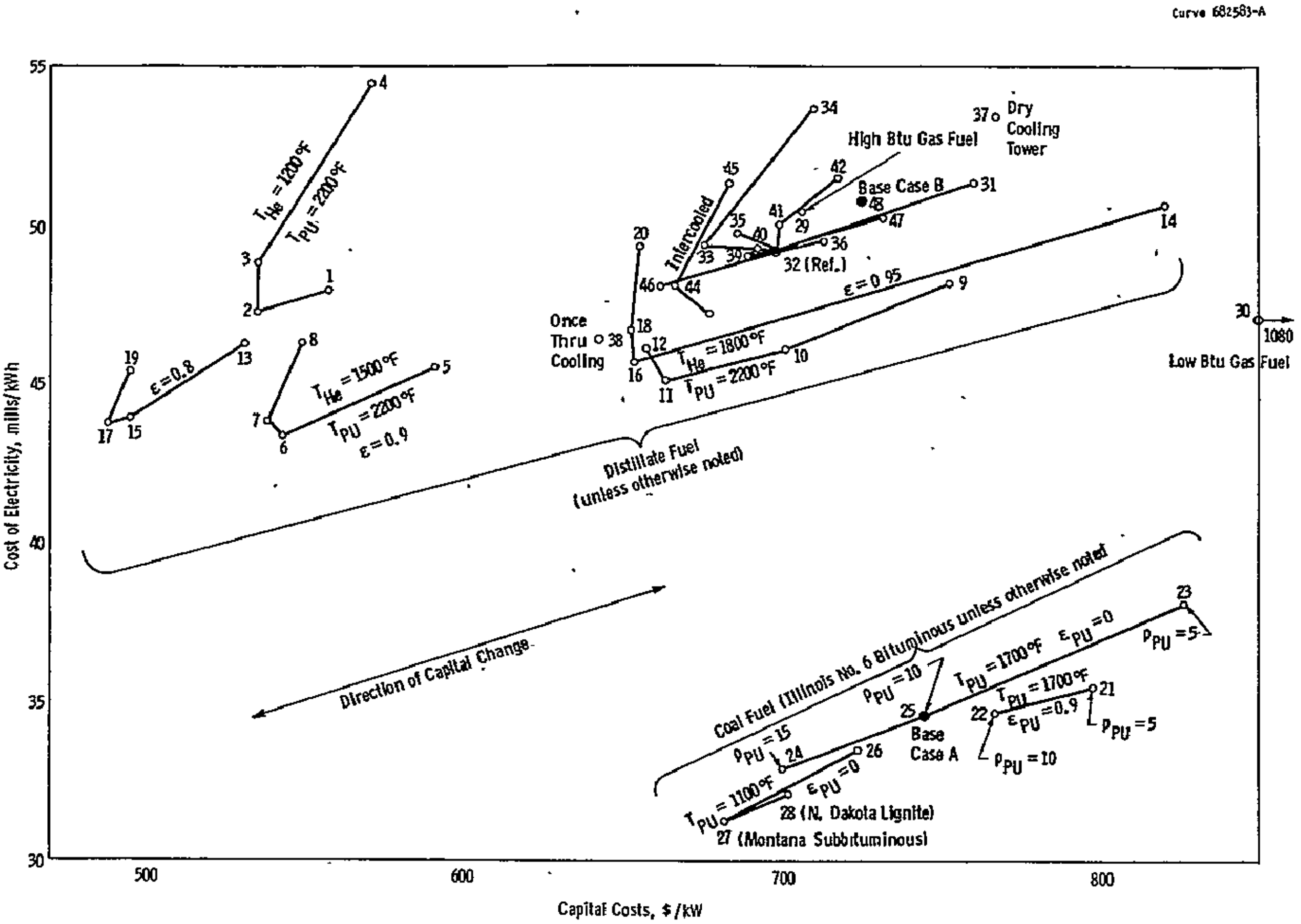

Fig. 7.58 —Cost of electricity vs capital cost for a recuperated closed-cycle gas turbine system

pump-up pressure ratio and mainly reflect increasing capitalization for lower pressure level combustion. The COE for Point R25 is 9.61 mills/MJ (34.6 mills/kWh). Points R21, R22 are similar but with added recuperation (0.9 effectiveness) for the pump-up set. At a pressure ratio of 10 to 1, Point R22 has a performance improvement over Point R25 which is almost exactly countered by the added capitalization for no net change in COE. At a pressure ratio of 5 to 1 much more heat can be recovered, and Point R21 is considerably improved in both capitalization and COE over Point R23. Points R26, R27, R28 have the different specified types of coal but with the pump-up turbine inlet temperature brought down to 866°K (1100°F). Point R26 reflects an improvement over Point R25, Base Case A.

There is some difference in COE associated with various coal fuels [about 0.55 mill/MJ (2 mills/kWh)], Montana subbituminous being the best.

Point R32 using distillate at 866°K (1100°F) for the pump-up turbine inlet temperature is a reference for most of the remaining points. Point R48, Base Case B, in itself has a COE of 14.11 mills/MJ (50.8 mills/kWh) burning distillate fuel. By switching to coal fuel, a considerable reduction in COE would be expected. Such a plant would resemble a typical steam power plant except that the conventional steam turbine generator would be replaced by a closed-cycle recuperated helium gas turbine. Point R30, burning low-Btu gas, has a 13.08 mills/MJ (47.1 mills/kWh) COE and is off-scale for capitalization. It appears to have no redeeming attributes. At a COE of 14 mills/MJ (50.4/kWh) the high-Btu gas fuel point, R29, also, is not an attractive option.

The combined closed cycles shown on Figure 7.59 generally had lower capitalization and better performance than did the recuperated cycles. The coal-fueled points of both types of system appear to be similar. Point C41 burning Illinois No. 6 bituminous coal is closely related with respect to cycle configuration to Point R26. Point C41 has a COE of 8.75 mills/MJ (31.5 mills/kWh) and a capitalization of $701/kW. compared to corresponding values of 9.03 mills/MJ (32.5 mills/kWh) and

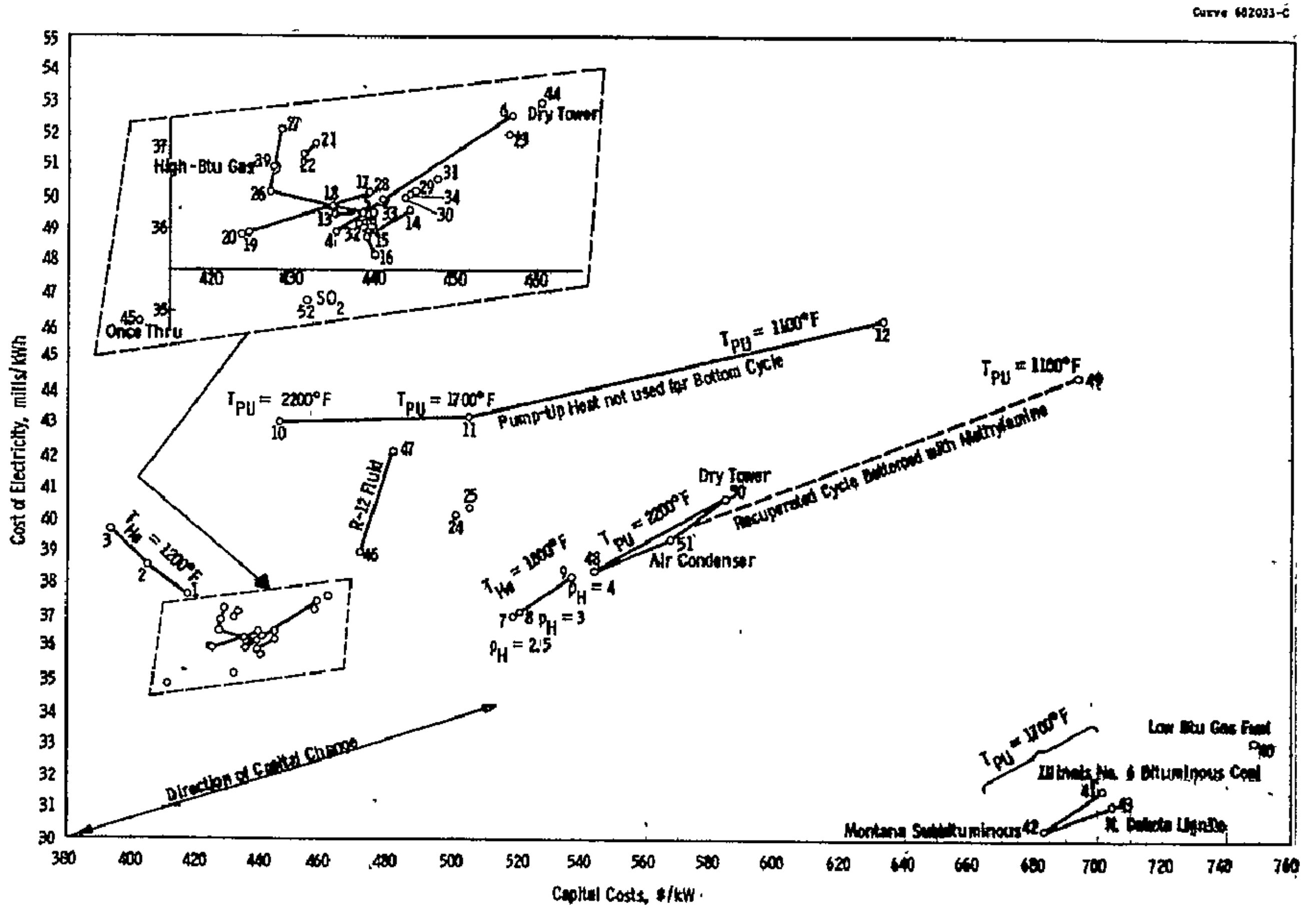

Fig. 7.59—Closed combined cycles cost of electricity vs capitalization (Number points refer to the parametric point number)

$692/kW for Point R26. The lowest COE, Point C42 burning Montana subbituminous coal has a value of 8.42 mills/MJ (30.3 mills/kWh) for COE 0.278 mill/MJ (1 mill/kWh) lower than the corresponding, and best, recuperated Point R27.

The higher turbine inlet temperature pump-up points using distillate fuel are definitely better with combined rather than recuperated, cycles. The higher cost of distillate fuel, however, eliminates it from competition with the coal-fueled points.

On Figure 7.59, the congestion of points about the base case, Point C5, requires the use of an inset at larger scale to differentiate them. Points C1, C2, C3; C4, C5, C6; C7, C8, C9 are a sequence with varying helium temperatures of 922, 1089, and 1255°K (1200, 1500, and 1800°F), respectively. For Points C10, C11, C12, the exhaust heat of the pump-up set is not utilized for heating the vapor of the bottom cycle. Of course, this is wasteful, and the COE values of 11.94 mills/MJ (43 mills/kWh) and higher reflect this fact.

Although the COE levels for the closed combined cycles would appear to be too high to be competitive relative to some of the other ECAS energy conversion concepts, certain effects have been identified which can be valid in other applications, such as open combined cycles or nonfossil fuel closed cycles for gas-cooled nuclear reactors. These effects relate to the base case, Point C5. Points C13, C14, C15, C16 show an advantage in cycle performance as the helium compressor inlet temperature is allowed to rise. The maximum advantage is about 0.11 mill/MJ (0.4 mill/kWh) for Point C16 compared to Point C5 for a compressor inlet temperature of 450°K (350°F) compared to 366°K (200°F). Points C17, C18, C19, C20 are similar in that the helium temperature from the vapor generators is allowed to rise, producing the same improvement in bottom cycle fit as did Points C13, C14, C15, C16. Here, however, a precooler was intentionally added to bring the compressor inlet temperature down to 309°K (96.5°F). The improvement in COE over Point C5 was only 0.05 mil/MJ (0.2 mil/kWh) compared to the 0.11 mill/MJ (0.4 mill/kWh) improvement when the precooler was not applied.

Points C46, C47 use dichloridifluorimethane (R-12) as a bottoming fluid. The poorer thermodynamic fit due to the stability limit resulted in a fall-off in performance such that the COE for Point C46 is 10.78 mills/MJ (38.8 mills/kWh), 0.75 mill/MJ (2.7 mills/kWh) poorer than for Point C5. Point C47 had an added loss from the rejected heat of the superheated R-12 turbine and has a COE value of 11.69 mills/MJ (42.1 mills/kWh), 1.64 mills/MJ (5.9 mills/kWh) poorer than has Point C5.

Points C48, C50, C51 . . . C49 utilize methylamine bottoming fluid and are subposed below recuperated cycles; C48, C50, C51 below a 1478°K (2200°F) pump-up cycle, and C49 below an 866°K (1100°F) pump-up cycle. All have 1089°K (1500°F) turbine inlet temperature helium cycles. The large amount of heat exchange equipment required for these cycles results in a high capitalization so that the lowest COE (Point C48) is 0.61 mill/MJ (2.2 mills/kWh) poorer than Point C5. The 866°K (1100°F) case, Point C49, is especially unfavorable in this respect and has a COE 2.36 mills/MJ (8.5 mills/kWh) poorer than Point C5.

In addition to their relation to Point C5, Points C48, C50, C51 relate to each other as to the method of heat rejection. Point C48 rejects heat to a wet cooling tower by means of a cooling-water loop. Point C51, however, rejects its cycle heat to a dry tower by condensing the methylamine directly in an air condenser. Point C50 has poorer performance and greater capitalization than Point C48 so that the COE is 0.61 mill/MJ (2.2 mills/kWh) higher. This is analogous to the relation between Point C44 (dry tower) and Point C5 (wet tower) with steam which has a COE difference of 0.39 mill/MJ (1.4 mills/kWh). The difference between 0.61 and 0.39 mill/MJ (2.2 and 1.4 mills/kWh) is primarily due to differences in capitalization which, due to the novelty of some of the special bottoming fluid apparatus, is somewhat uncertain. Point C51 has better performance and lower capitalization than Point C50 so that its CCE is 0.36 mill/MJ (1.3 mills/kWh) lower. There is no counterpart for the steam bottomed cycles.

The direct condensing for Point C51 is made possible because the volumetric flow from the bottom turbine is low enough to deploy it directly to air condensers. Actually, the pipe size required for the methylamine vapor is of the same magnitude as that required for a cooling-water loop. The pipe size for collecting the condensed methylamine is much less than that required for cooling water. Since the heat transfer to air for the condenser and that for cooling water for a loop are both dominated by the air-side heat transfer coefficient, both types of surface would be highly finned and be comparable in cost. This same effect should be applicable for a low-boiling fluid such as R-12, sulfur dioxide, or any other fluid of this type.

Point C52 utilizes sulfur dioxide as a bottom fluid under a 1478°K (2200°F) turbine inlet temperature pump-up cycle and 1089°K (1500°F) turbine inlet temperature helium cycle. The high stability limits for sulfur dioxide permit its operation to levels of 811°K (1000°F). This bottoming cycle using supercritical pressure levels was carefully fitted to the heat available lines, and the superheated sulfur dioxide exhaust energy was utilized by regenerative feed heating. The resulting high efficiency and small turbine size resulted in a COE of 0.306 mill/MJ (1.1 mills/kWh) lower than that of the base case (Point C5). It should be possible to realize this same effect in other related types of cycles, such as open combined cycles, and in nuclear applications.

In addition to the overall descriptions provided by the composite plots of mills per kilowatt hour versus capitalization, the effect of specific parameter variations upon COE has been investigated.

Figure 7.60 illustrates the effect of helium cycle pressure ratio and recuperator effectiveness upon the COE for the recuperated closed cycle. Pump-up turbine inlet temperature is 1478°K (2200°F) and compressor ratio is 10 to 1. The fuel is distillate from coal. Helium turbine inlet temperature is 1089°K (1500°F). The optimum COE occurs at a compressor pressure ratio of 2.5 to 1 and with a recuperator effectiveness of 0.9. Although for higher recuperator effectiveness efficiency

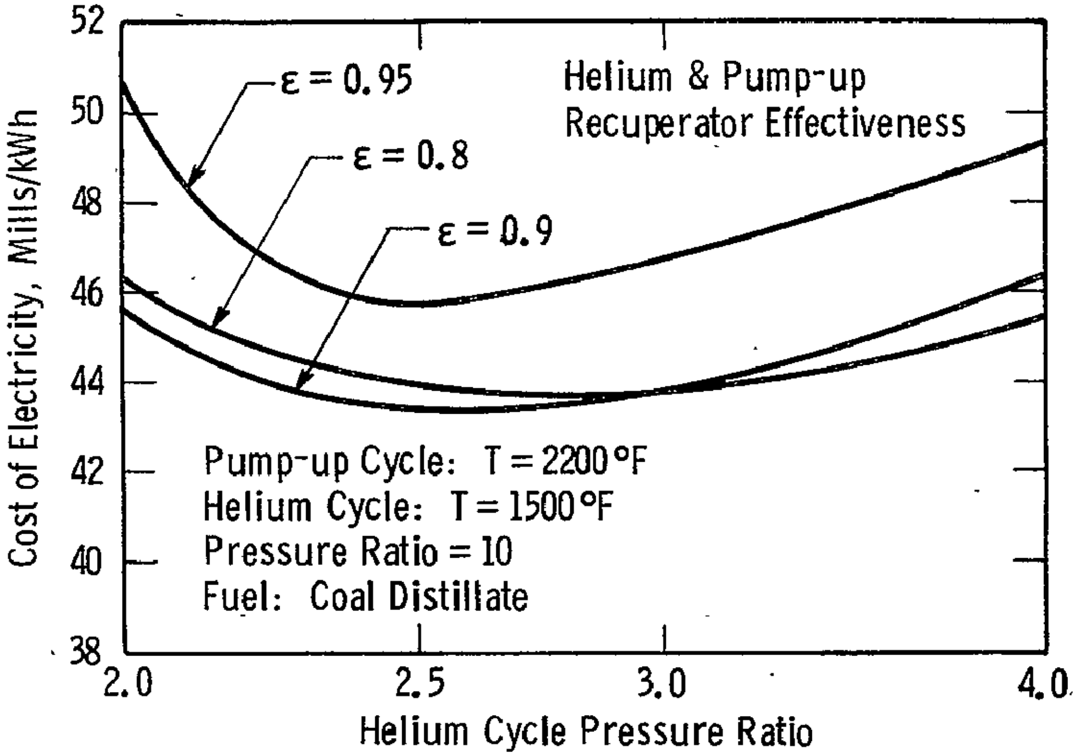

Fig. 7.60—Influence of recuperator effectiveness on cost of electricity (Recuperated closed-cycle)

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can be improved, additional capital costs outweigh the gains and the result is a net degrading of the COE advantage.

Table 7.24 principally illustrates the impact of the higher distillate fuel prices on COE for four closed recuperated cycle cases.

Points R25 and R26 are each fixed on coal fuel. Point R25 corresponds to Base Case A, and Point R26 is similar, except that the pump-up turbine inlet temperature is reduced by transferring more primary heat to the helium cycle. This change resulted in a net reduction in COE. Point R6 has the added effect of recuperation in the pump-up cycle, and overall efficiency consequently reflects an improvement. Distillate fuel was used, however, and the higher COE reflects the added fuel costs. Point R48, Base Case B, utilizes an atmospheric pressure furnace as a substitute for the pump-up cycle and reflects a decrease in efficiency relative to Point R6.

Figure 7.61 applies to the combined closed cycles and illustrates the effect of helium cycle turbine inlet temperature and compressor pressure ratio on COE. The optimum combination of these parameters appears at 1089°K (1500°F) and 2 to 1, respectively.

Similar to the above described recuperated cycle tabulation, Table 7.25 illustrates the effects of fuel type and cycle arrangement on COE for selected combined closed cycles.

A comparison of recuperated and combined closed cycles with respect to fuel price sensitivity is presented in Table 7.26. In each case, the cost of fuel has been arbitrarily escalated from 0.806 to \$1.42/GJ (0.85 to \$1.50/10^6 Btu), an increase of 76%.* The combined closed cycle is preferred here, with its overall COE escalating 18%, as compared with 20% for the recuperated cycle example.

The natural resource requirements consisting of coal, sorbent (for gasification systems), water for heat rejection, gasification process, etc., and land usage have been estimated and are given for the recuperated and combined closed-cycle systems in Tables 7.27 and 7.28, respectively.

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* Indicated by number in parentheses in Table 7.26.

Dwg. 6363A79

TABLE 7.24 — RECUPERATED CLOSED-CYCLE RESULTS

Fuel Type	Coal	Coal	Dist. →	→
Fuel Cost, $/10^6 Btu	0.85	.85	2.60 →	→
Cost of Elec., mills/kWh	33.7	32.5	42.6	45.9
Capital Cost, $/kW	719	692	519	573
Efficiency, %	32.0	33.3	34.6	32.5
Power Output, MW				
Pump-up	86	38	112	
Helium	231	316	217	360
Total	317	354	429	360
Helium Cycle				
Temp., °F	1500 →	→	→	→
P. R.	2.5 →	→	→	→
Recup. Eff.	.90 →	→	→	→
Pump Up Cycle				
Temp., °F	1700	1100	2200	No
P. R.	10	10	10	Pump
Recup. Eff., %	--	--	90	Up
Capacity Factor	0.65 →	→	→	→
Parametric Point	25	26	6	48

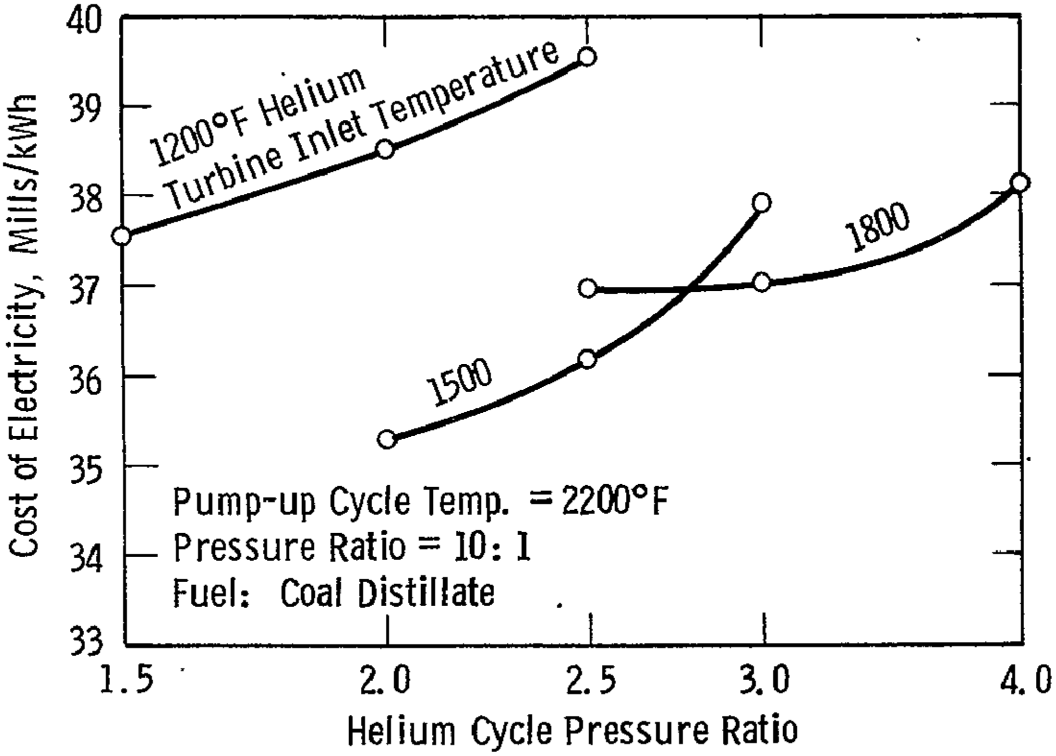

Fig. 7.61 —Influence of helium temperature and pressure ratio on cost of electricity for a closed combined cycle

Dwg. 6363A80

TABLE 7.25 — COMBINED CLOSED-CYCLE RESULTS

Fuel Type	Coal	Dist. →	→	→	→
Fuel Cost, $\$/10^6$ Btu	0.85	2.60 →	→	→	→
Cost of Elec., mills/kWh	31.5	36.2	38.9	38.4	35.1
Capital Cost, \$/kW	701	439	470	544	431
Efficiency, %	38.2	40.9	37.8	43.1	42.5
Power Output, MW					
Pump-up	84	113	113	110	113
Helium	117	86	86	198	86
Bottom	179	191	165	105	209
Total	380	390	364	413	408
Helium Cycle					
Temp., °F	1500 →	→	→	→	→
P. R.	2.5 →	→	→	→	→
Pump Up Cycle					
Temp., °F	1700	2200 →	→	→	→
P. R.	10				
Bottom Cycle Fluid	Steam	Steam	R-12	Methyl-amine	SO_2
Capacity Factor	0.65 →	→	→	→	→
Parametric Point	41	5	46	48	52

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Table 7.26 Comparison of Closed Cycle Coal Fired Gas Turbine Plants

	Recuperative			Combined		
Cost of Fuel, $\$/10^6$ Btu	0.85	1.50	(1.76)	0.85	1.50	(1.76)
Cost of Elec., Mills/kWh	33.50	40.10	(1.20)	31.50	37.30	(1.18)
Cost of Fuel, Mills/kWh	8.70	15.40		7.60	13.40	
Capital Cost, $/kW	692.00			701.00		
Efficiency, %	33.30			38.20		
Capacity Factor	0.65			0.65		
Parametric Point	26.00			41.00		

Table 7.27 –RECUPERATED HELIUM CLOSED CYCLE C T SYSTEM NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
COAL, LB/KW-HR	2.06983	2.10860	2.21610	2.53596	1.85967	1.81229	1.85715	2.00738
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.000	.000	.000	.000	.000	.000	.000	.000
COOLING WATER	.000	.000	.000	.000	.000	.000	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	94.23	95.24	100.35	121.60	78.09	77.72	79.50	85.38
MAIN PLANT	17.57	17.76	18.30	19.86	16.26	16.21	16.45	17.24
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	76.56	78.03	82.05	101.74	61.83	61.51	63.05	68.14

PARAMETRIC POINT	9	10	11	12	13	14	15	16
COAL, LB/KW-HR	1.68006	1.64929	1.65717	1.75100	2.04515	1.70092	1.96360	1.73319
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.000	.000	.000	.000	.000	.000	.000	.000
COOLING WATER	.000	.000	.000	.000	.000	.000	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	67.33	66.22	66.86	69.91	86.84	68.10	83.66	69.26
MAIN PLANT	15.49	15.32	15.41	15.89	17.43	15.60	17.01	15.78
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	51.84	50.90	51.45	54.04	69.41	52.50	66.64	53.48

PARAMETRIC POINT	17	18	19	20	21	22	23	24
COAL, LB/KW-HR	1.96666	1.80141	2.06561	1.87685	.91364	.92921	1.07741	.96124
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.48340	.49164	.57006	.50859
TOTAL WATER, GAL/KW-HR	.000	.000	.000	.000	.155	.158	.183	.163
COOLING WATER	.000	.000	.000	.000	.000	.000	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.1001	.1013	.1190	.1053
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.05482	.05575	.06454	.05767
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	83.79	77.30	87.70	90.37	169.82	167.09	179.69	172.59
MAIN PLANT	17.03	16.15	17.55	17.10	19.37	19.57	21.40	19.97
DISPOSAL LAND	.00	.00	.00	.00	80.08	81.44	94.43	84.25
LAND FOR ACCESS RR	66.76	61.15	70.16	73.28	70.37	66.09	63.96	68.37

PARAMETRIC POINT	25	26	27	28	29	30	31	32
COAL, LB/KW-HR	.98976	.94902	1.17910	1.02211	1.45517	1.02058	1.68592	1.27088
SORBANT OR SEED,LB/KW-HR	.52358	.50212	.13167	.14575	.00000	1.07997	.00000	.00000
TOTAL WATER, GAL/KW-HR	.168	.161	.085	.088	.000	.344	.000	.000
COOLING WATER	.000	.000	.000	.000	.000	.000	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.05879	.00000	.00000
CONDENSATE MAKE UP ,	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
WASTE HANDLING SLURRY	.1084	.1039	.0273	.0302	.0000	.2236	.0000	.0000
SCRUBBER WASTE WATER	.05939	.05694	.05739	.05807	.00000	.06123	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	171.51	131.13	131.59	131.35	89.79	257.38	95.04	94.43
MAIN PLANT	20.33	19.05	19.09	19.33	14.61	19.37	15.15	15.09
DISPOSAL LAND	96.75	33.19	33.27	36.60	.00	153.72	.00	.00
LAND FOR ACCESS RR.	54.53	78.90	79.22	75.42	75.18	84.29	79.89	79.34

Table 7.27 - RECUPERATED HELIUM CLOSED CYCLE G T SYSTEM NATURAL RESOURCE REQUIREMENTS
Continued

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  PARAMETRIC POINT              33       34       35       36       37       38       39       40
  COAL, LB/KW-HR             1.94103  2.16342  1.94553  1.85433  2.02146  1.90602  1.88353  1.89332
  SORBANT OR SEED,LB/KW-HR    .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
  TOTAL WATER, GAL/KW-HR        .000     .000     .000     .000     .000     .000     .000     .000
     COOLING WATER              .000     .000     .000     .000     .000     .000     .000     .000
     GASIFIER PROCESS H2O     .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     CONDENSATE MAKE UP  ,    .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     WASTE HANDLING SLURRY     .0000    .0000    .0000    .0000    .0000    .0000    .0000    .0000
     SCRUBBER WASTE WATER     .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     NOX SUPPRESSION          .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
  TOTAL LAND ACRES/100MWE      97.44   113.70    92.51    98.79   256.29    14.71    94.89    95.39
     MAIN PLANT                15.40    16.45    15.42    15.04    15.97    14.71    15.14    15.19
     DISPOSAL LAND               .00      .00      .00      .00      .00      .00      .00      .00
     LAND FOR ACCESS RR        82.04    97.25    77.09    83.75   240.32      .00    79.75    80.19


  PARAMETRIC POINT              41       42       43       44       45       46       47       48
  COAL, LB/KW-HR             1.93152  1.99351  1.75468  1.86632  2.05863  1.87688  1.87688  1.92924
  SORBANT OR SEED,LB/KW-HR    .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
  TOTAL WATER, GAL/KW-HR        .000     .000     .000     .000     .000     .000     .000     .000
     COOLING WATER              .000     .000     .000     .000     .000     .000     .000     .000
     GASIFIER PROCESS H2O     .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     CONDENSATE MAKE UP  ,    .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     WASTE HANDLING SLURRY     .0000    .0000    .0000    .0000    .0000    .0000    .0000    .0000
     SCRUBBER WASTE WATER     .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     NOX SUPPRESSION          .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
  TOTAL LAND ACRES/100MWE      97.00   105.17    85.36    93.93   108.43    94.43    94.43    97.37
     MAIN PLANT                15.35    15.65    14.64    15.04    15.96    15.09    15.09    11.89
     DISPOSAL LAND               .00      .00      .00      .00      .00      .00      .00      .00
     LAND FOR ACCESS RR        81.65    89.52    70.72    78.89    92.47    79.34    79.34    85.48


  PARAMETRIC POINT              49       50       51       52       53       54       55       56
  COAL, LB/KW-HR              .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
  SORBANT OR SEED,LB/KW-HR    .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
  TOTAL WATER, GAL/KW-HR        .000     .000     .000     .000     .000     .000     .000     .000
     COOLING WATER              .000     .000     .000     .000     .000     .000     .000     .000
     GASIFIER PROCESS H2O     .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     CONDENSATE MAKE UP  ,    .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     WASTE HANDLING SLURRY     .0000    .0000    .0000    .0000    .0000    .0000    .0000    .0000
     SCRUBBER WASTE WATER     .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
     NOX SUPPRESSION          .00000   .00000   .00000   .00000   .00000   .00000   .00000   .00000
  TOTAL LAND ACRES/100MWE        .00      .00      .00      .00      .00      .00      .00      .00
     MAIN PLANT                  .00      .00      .00      .00      .00      .00      .00      .00
     DISPOSAL LAND               .00      .00      .00      .00      .00      .00      .00      .00
     LAND FOR ACCESS RR          .00      .00      .00      .00      .00      .00      .00      .00

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Table 7.28 COMBINED AIR-HELIUM-STEAM TURB CYCLE NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
COAL, LB/KW-HR	1.57977	1.77530	1.97888	1.52580	1.53433	1.57369	1.40824	1.41182
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.597	.508	.546	.615	.577	.547	.584	.549
COOLING WATER	.691	.603	.541	.610	.572	.543	.579	.544
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00577	.00480	.00411	.00527	.00478	.00433	.00501	.00466
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	47.07	43.87	46.04	43.32	43.51	39.74	40.42	40.50
MAIN PLANT	15.96	16.49	17.05	15.06	15.10	15.36	14.35	14.36
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	31.11	27.39	28.99	28.26	28.41	24.37	26.07	26.14

PARAMETRIC POINT	9	10	11	12	13	14	15	16
COAL, LB/KW-HR	1.45359	2.00152	1.88382	1.80982	1.54138	1.52451	1.51380	1.50184
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.493	.401	.488	.590	.559	.597	.621	.650
COOLING WATER	.489	.398	.485	.585	.555	.592	.616	.644
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00409	.00317	.00386	.00465	.00463	.00495	.00515	.00539
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	37.04	36.22	42.85	43.88	43.69	43.27	43.01	47.36
MAIN PLANT	14.61	17.69	16.21	15.19	15.15	15.05	14.99	14.92
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	22.43	18.53	26.65	28.69	28.55	28.23	28.03	32.44

PARAMETRIC POINT	17	18	19	20	21	22	23	24
COAL, LB/KW-HR	1.55091	1.55031	1.55391	1.55091	1.60839	1.50243	1.56385	1.67091
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.549	.549	.549	.549	.611	.643	.573	.604
COOLING WATER	.544	.544	.544	.544	.607	.639	.568	.599
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00455	.00455	.00455	.00455	.00454	.00456	.00452	.00501
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	43.92	43.92	43.92	43.92	45.32	45.18	44.23	43.45
MAIN PLANT	15.20	15.20	15.20	15.20	15.54	15.51	15.28	15.09
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	28.72	28.72	28.72	28.72	29.78	29.67	28.96	28.36

PARAMETRIC POINT	25	26	27	28	29	30	31	32
COAL, LB/KW-HR	1.67891	1.57967	1.63076	1.53909	1.54016	1.53910	1.54433	1.52721
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.608	.559	.538	.590	.604	.590	.608	.571
COOLING WATER	.503	.554	.533	.585	.599	.585	.603	.567
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00459	.00463	.00446	.00489	.00500	.00489	.00497	.00473
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	43.63	44.62	40.83	43.63	43.76	43.64	44.05	43.34
MAIN PLANT	15.13	15.37	15.66	15.13	15.16	15.14	15.24	15.06
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	28.50	29.25	25.17	28.50	28.59	28.51	28.82	28.28

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Table 7.28    COMBINED AIR-HELIUM-STEAM TURB CYCLE   NATURAL RESOURCE REQUIREMENTS
Continued

PARAMETRIC POINT              33      34      35      36      37      38      39      40
COAL, LB/KW-HR             1.53535 1.53840 1.53238 1.53519 1.53430 1.53430 1.19858  .82726
SORBANT OR SEED,LB/KW-HR    .00000  .00000  .00000  .00000  .00000  .00000  .00000  .43771
TOTAL WATER, GAL/KW-HR       .584    .592    .572    .582    .574    .574    .563    .780
   COOLING WATER             .579    .587    .567    .577    .570    .570    .558    .587
   GASIFIER PROCESS H2O     .00000  .00000  .00000  .00000  .00000  .00000  .00000  .14765
   CONDENSATE MAKE UP  ,    .00484  .00491  .00474  .00482  .00480  .00480  .00467  .00491
   WASTE HANDLING SLURRY     .0000   .0000   .0000   .0000   .0000   .0000   .0000   .0906
   SCRUBBER WASTE WATER     .00000  .00000  .00000  .00000  .00000  .00000  .00000  .04964
   NOX SUPPRESSION          .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
TOTAL LAND ACRES/100MWE      43.56   43.61   43.46   43.54   43.36   43.36   39.71  127.02
   MAIN PLANT                15.12   15.13   15.09   15.11   15.07   15.07   12.65   27.39
   DISPOSAL LAND               .00     .00     .00     .00     .00     .00     .00   69.54
   LAND FOR ACCESS RR        28.45   28.49   28.37   28.43   28.30   28.30   27.07   30.08


PARAMETRIC POINT              41      42      43      44      45      46      47      48
COAL, LB/KW-HR              .82728 1.02841 1.35436 1.58620 1.50600 1.65701 1.85399 1.45439
SORBANT OR SEED,LB/KW-HR    .43771  .11693  .12918  .00000  .00000  .00000  .00000  .00000
TOTAL WATER, GAL/KW-HR       .756    .681    .675    .005    .005    .810   1.038    .679
   COOLING WATER             .611    .631    .593    .000    .000    .810   1.038    .679
   GASIFIER PROCESS H2O     .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
   CONDENSATE MAKE UP  ,    .00454  .00457  .00450  .00468  .00480  .00000  .00000  .00000
   WASTE HANDLING SLURRY     .0906   .0242   .0267   .0000   .0000   .0000   .0000   .0000
   SCRUBBER WASTE WATER     .04954  .05091  .05147  .00000  .00000  .00000  .00000  .00000
   NOX SUPPRESSION          .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
TOTAL LAND ACRES/100MWE      62.35   60.56   62.56   93.77   14.89   61.88   74.20   55.05
   MAIN PLANT                15.48   15.68   15.84   15.45   14.89   15.87   17.00   14.65
   DISPOSAL LAND             17.45   14.83   15.19     .00     .00     .00     .00     .00
   LAND FOR ACCESS RR        29.41   30.05   30.53   78.32     .00   46.01   57.20   40.40


PARAMETRIC POINT              49      50      51      52      53      54      55      56
COAL, LB/KW-HR             1.56552 1.52738 1.47313 1.47545  .00000  .00000  .00000  .00000
SORBANT OR SEED,LB/KW-HR    .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
TOTAL WATER, GAL/KW-HR       .806    .000    .000    .677    .000    .000    .000    .000
   COOLING WATER             .806    .000    .000    .677    .000    .000    .000    .000
   GASIFIER PROCESS H2O     .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
   CONDENSATE MAKE UP  ,    .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
   WASTE HANDLING SLURRY     .0000   .0000   .0000   .0000   .0000   .0000   .0000   .0000
   SCRUBBER WASTE WATER     .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
   NOX SUPPRESSION          .00000  .00000  .00000  .00000  .00000  .00000  .00000  .00000
TOTAL LAND ACRES/100MWE      59.45  156.59  137.57   55.75     .00     .00     .00     .00
   MAIN PLANT                13.96   15.19   14.84   14.73     .00     .00     .00     .00
   DISPOSAL LAND               .00     .00     .00     .00     .00     .00     .00     .00
   LAND FOR ACCESS RR        45.49  141.41  122.73   40.97     .00     .00     .00     .00

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7.7 Conclusions and Recommendations

7.7.1 Conclusions

In comparison with other ECAS energy conversion systems, both the closed recuperated and combined-cycle systems are not generally attractive for base-load (or lower) capacity factor operation.

The combined closed-cycle systems, in general, have a lower COE and better performance than the recuperated closed-cycle systems, although for operation on coal fuel the results for both types of cycle are nearly alike. Substitution of a sulfur dioxide bottoming fluid system for the steam system results in reduction of the overall base-load COE because of higher efficiency and reduced capital costs.

Firing of the coal-derived distillate fuel is not competitive with direct burning of coal for base-load operation in this type of plant. Further, of the types of coals investigated for direct burning, the Montana subbituminous results in the lowest COE. Firing high-Btu gas, as well as using integrated low-Btu gasification, are not attractive options because of high capital cost.

As with open-cycle gas turbine systems, increasing the closed-cycle turbine inlet temperature results in improved cycle efficiency for both the recuperated and combined closed-cycle systems. Also, the closed-cycle compressor pressure ratio for optimum efficiency increases gradually with higher turbine inlet temperatures. For example, the nonintercooled recuperated and combined closed cycle systems, at a turbine inlet temperature of 922°K (1200°F), show optimum therodynamic efficiency at a compressor pressure ratio of approximately 2 to 1; while at 1255°K (1800°F) turbine inlet temperature the optimum occurs at a value of nearly 2.5 to 1.

In contrast with the open-cycle gas turbine systems, however, the COE is not a continually decreasing function of higher turbine inlet temperature. For both the recuperated and combined cycles, the minimum COE was determined to occur at a turbine inlet temperature of 1089°K

(1500°F). This result follows from the greatly increasing heat exchanger cost at the higher turbine inlet temperatures.

The influence of recuperator effectiveness for the recuperated closed-cycle systems is similar to the above described effect of turbine inlet temperature. Although increasing the nominal recuperator effectiveness results in a steady improvement in thermodynamic efficiency, the optimum value for a minimum COE is approximately 0.9.

Results of alternative methods of heat rejection, including wet cooling tower, dry cooling tower, and once-through cooling, are similar to the results determined in the gas-steam combined-cycle section of this study. That is, minimum COE obtained with once-through cooling, maximum COE with dry tower heat rejection. Also, the difference in COE between wet and dry tower rejection is larger than that between once-through and wet tower cooling.

The use of compressor intercooling in conjunction with the recuperated-cycle configuration results in a reduced COE with the optimum compressor pressure ratio at a value of approximately 5 to 1 at the 1089°K (1500°F) turbine inlet temperature level.

7.7.2 Recommendations

Certain features of the closed-cycle system merit further investigation.

- Due to the high leverage of the helium heater costs on the plant cost and the overall COE further work on this cycle should begin with more detailed technical and economic evaluation of the helium heater system.
- The use of closed helium cycle with bottoming cycle should be further studied for other heat source applications, such as in a high-temperature gas-cooled nuclear reactor.
- The feature of bottoming with a low-boiling, high-temperature stable fluid, such as sulfur dioxide or ammonia, should be studied further.

- The feature of deploying a low-boiling fluid for direct condensing in an air condenser should receive additional investigation.

7.8 References

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