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WESTINGHOUSE PHASE I FINAL REPORT
Volume V – COMBINED GAS-STEAM TURBINE CYCLES

by
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WESTINGHOUSE ELECTRIC CORPORATION RESEARCH LABORATORIES

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16. Abstract

Combined cycle gas-steam turbine plants can have efficiencies several points higher than convention steam plants. Induction of low pressure steam into the steam turbine improves the plant efficiency Post firing of the boiler of a high temperature combined cycle plant is found to increase net power but to worsen efficiency. A gas turbine pressure ratio of 12 to 1 was found to be close to optimum at all gas turbine inlet temperatures studied.

The coal using combined cycle plant with an integrated low-Btu gasifier calculated to have a plant efficiency of 43.6%, a capitalization of $497/kW, and a cost of electricity of 6.75 mills/MJ (24.3 mills/kWh). This combined cycle plant should be considered for base load power generation.

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- R. W. Foster-Pegg, who decided upon the parametric points to be evaluated and calculated the efficiencies of plants which used steam turbine inductions and/or throttle condition variations.
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SUMMARY

The combined gas-steam turbine cycles studied typically uses four 1478°K. (2200°F), 12 to 1 gas turbines which exhaust into modular heat recovery steam generators. A single subcritical steam turbine generator bottoms these units. The cycle parametric investigations are based on the use of clean distillate from coal as fuel. Specific arrangements are also evaluated which include the firing of low-Btu gas from an integrated coal gasifier. Both reheat and nonreheat steam cycles are considered. Induction of supplementary steam into the turbine cycle at one or two temperatures below the throttle pressure is also considered, the first into the cold reheat pipe and, if used, the second into the crossover pipe between the IP and LP turbines.* Low pressure steam inductions provides a closer fit between the gas turbine exhaust gas cooling curve and the water-steam heating curve and result in a lower stack gas temperature. Typically, the use of steam induction can add 2 or 3 points to the plant cycle efficiency.

The 16.547 MPa/811°K/811°K (2400 psi/1000°F/1000°F) reheat steam cycle with an unfired boiler and two steam inductions after the throttle is the most efficient cycle investigated. This steam plant with a 1478°K (2200°F) gas turbine burning clean distillate from coal and a 16.7°K (30°F) approach of the exhaust gas to the saturation throttle steam temperature in the boiler achieves a cycle efficiency of about 48%. This is a 20% reduction in heat rate compared to the oil burning all-steam plant with similar design sophistication.

Post firing of the boiler of a combined gas-steam turbine cycle is found to increase the net plant power output but, in general, to worsen efficiency.

* Induction of 206.8 kPa (30 psi) abs steam into the low pressure turbine is assumed most commonly.

Combined cycle efficiency improves significantly as the gas turbine inlet temperature is increased. At a turbine inlet temperature of 1478°K (2200°F), an efficiency improvement of 2 points/55.6°K (100°F) increase in turbine inlet temperature is found. This tapers to about 1 point/55.6°K (100°F) at turbine inlet temperatures of 1700°K (2600°F).

A gas turbine pressure ratio of about 12 to 1 is close to optimum for these combined cycles at all gas turbine inlet temperatures studied.

The 783 MWe combined cycle plant burning low-Btu gas from an integrated coal gasifier is found to have an efficiency of 42.3% compared to 46.2% for the corresponding clean distillate burning plant. The coal using plant has a capitalization of $497/kW, just double that of the distillate burning plant. Nevertheless, the cost of electricity from the coal using plant is 6.75 mills/MJ (24.3 mills/kWh) compared to 7.68 mills/MJ (27.65 mills/kWh) for the distillate burning plant due to the difference in fuel cost [$0.806/MJ ($0.85/10^6 Btu) for coal compared to $2.46/MJ ($2.60/10^6 Btu) for clean distillate from coal]. Coal using combined cycle plants, therefore, have potential for future economic base load power generation systems.

6. COMBINED GAS-STEAM TURBINE CYCLES

6.1 State of the Art

6.1.1 Supercharged Boiler Combined Cycles

The first combined steam and gas turbine power plants were of the supercharged boiler type. About 40 supercharged boiler combined cycles were built in the 1930 to 1940 era by Brown Boveri, with capacities of up to 30 MW (References 6.1, 6.2, and 6.3). The first exhaust boiler combined cycles were constructed about 1950, and their application has progressed at a relatively consistent rate up to the present day.

A supercharged boiler cycle is more efficient than an exhaust boiler cycle when it is advantageous to fire the boiler; an unfired exhaust boiler combined cycle is the more efficient when power from the gas turbine and power generated by recovered heat is obtained at higher efficiency than power produced by firing the boiler (Reference 6.4). Thus, low-temperature, less efficient gas turbines favor fired supercharged boiler cycles; and higher-temperature, more efficient gas turbines favor unfired exhaust boiler cycles. The thermodynamic transition where the more efficient system changes from supercharged to exhaust boiler cycle is at a gas turbine firing temperature of about 1200°K (1700°F).

The thermodynamic superiority of the supercharged boiler cycle with lower-temperature gas turbines resulted in much attention being given to this cycle in the 1950s (References 6.5 through 6.10). The supercharged boiler cycle requires a boiler that is completely different from a conventional boiler and a somewhat special gas turbine. It is impossible to operate the steam and gas turbines of a supercharged combined cycle separately. These disadvantages discouraged development of supercharged boilers in this country, except for a few naval vessels where the size reduction of the boiler offered particular advantages (Reference 6.11).

In Europe, where industrial gas turbine firing temperatures are lower than in the United States, supercharged boilers are still receiving attention. At Lünen, Germany, a supercharged boiler combined cycle of 170 MW is in operation, and a 400 MW plant is being planned by the same company (Reference 6.12). It is reported from Russia that several combined cycles with supercharged boilers have been constructed up to 200 MW in size (References 6.13 and 6.14).

Combustion of coal and residual oil in pressurized fluid beds of limestone and dolomite is being advocated as a means of capturing the sulfur in the fuels. The fluid beds are contained in a form of supercharged boiler supplied with compressed air from a gas turbine compressor driven by an expander. The products of combustion in the boiler exhaust to the atmosphere through the expander, thus driving the compressor and producing useful power. Efficiency improvements possible with this system are small because fluid bed combustor operating temperatures are limited by the desulfurization reaction. The dusty effluent from the bed poses significant problems. Plans currently exist for a demonstration plant project to evaluate this type of system.

6.1.2 Exhaust Boiler Combined Cycles

Up to about 1965, combined cycles were viewed as a means of improving the efficiency of base-load plants and, in this era, gas turbine firing temperatures favored boiler firing.

As stated earlier, the supercharged boiler cycle was the more efficient cycle at the gas turbine temperatures prevailing in the early 1960s. The exhaust boiler cycle, however, has the advantage of using a relatively normal boiler design, and the capability for separate operation of the gas turbine and steam portions of the combined cycle. These advantages of the exhaust boiler cycle outweighed any thermodynamic advantage of the supercharged boiler cycle and confined serious consideration of combined cycles to the exhaust boiler cycle only.

In the early designs, emphasis was on low excess air-fired boiler combined cycles, as examplified by the Horseshoe Lake unit of

Oklahoma Gas and Electric Company (References 6.15 and 6.16) and the San Angelo Station of West Texas Utilities (References 6.17 through 6.21). Plants of this type offer efficiency improvements of 5 to 10%; but at the low cost of natural gas prevailing in the 1960s, savings of this order were generally regarded as insufficient to justify the selective fuel requirements of gas turbines, and few combined cycles were ordered by the utility companies.

The plants referenced above include gas turbines with base-load firing temperatures of 1061 and 1089°K (1450 and 1500°F) and steam conditions of 9.997 and 12.41 MPa (1450 and 1800 psi) gauge, 811°K (1000°F), with reheat of 811°K (1000°F). Both plants operate on natural gas at efficiencies equivalent to about 39% on oil.

The availability and reliability of these and other similar combined cycles have, in some cases, been better than comparable conventional plants.

A need has always existed for small, high-efficiency, economical power plants. Small size is unfavorable to high steam pressure conditions, and low-pressure steam is relatively inefficient. As a result, small-size steam power plants are relatively inefficient and of high specific cost. Gas turbines are relatively low in cost in the required small size and, in combined cycles, offer good efficiency. Firing the boiler of a small combined cycle is unattractive because the plant capacity is increased thereby, and the objective of a small capacity plant is violated. To satisfy these various requirements, designs were evolved for combined cycles of the highest possible efficiency with unfired boilers. With an unfired boiler and single steam pressure, the heat sink for the exhaust gas below saturation temperature is insufficient to absorb all potentially useful heat. This otherwise wasted heat can be employed to raise useful steam at a lower pressure and a lower saturation temperature than the main steam; and, therefore, multipressure steam cycles have become common for combined cycles with unfired or lightly fired boilers (Reference 6.26).

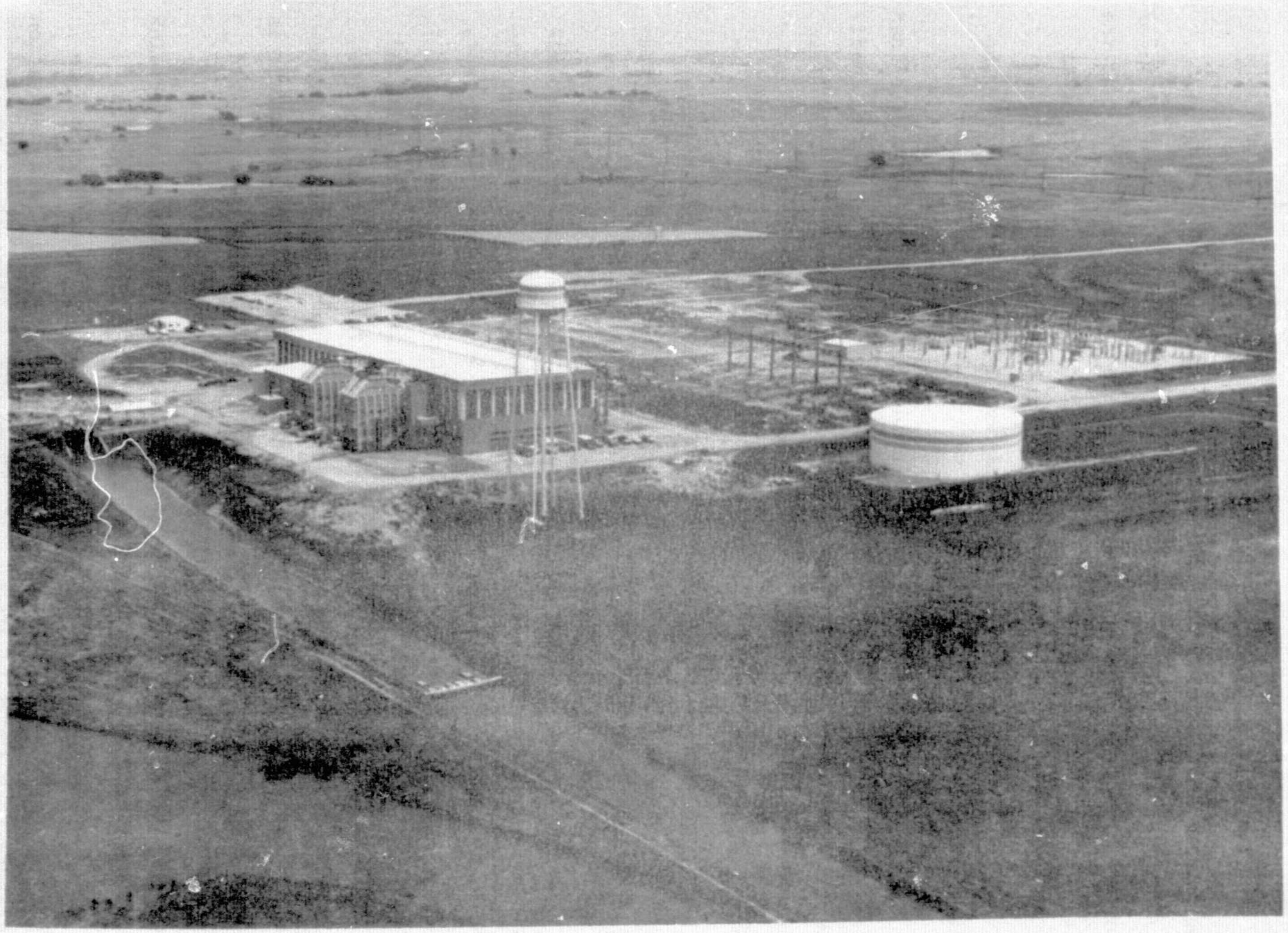

Fig. 6.1—Westinghouse PACE combined cycle power plant

About 1970, a need developed for utility power plants to generate midrange capacity; that is, for power which is required in daytime during midweek but is not required at night or weekends. Plants to supply this power are required to start and stop daily. Steam plants with high-pressure and high-temperature steam conditions have been found unsatisfactory in this service because of high stand-by costs when kept hot, or high start-up costs when started slowly to minimize thermal gradients and cracking of casings.

Nonreheat steam plants with lower pressure and temperature steam are better suited to this cycling service, but efficiency is poor. The combination of gas turbines with nonreheat steam turbines provides an obvious and well-suited midrange power plant with excellent efficiency and good tolerance to cycling.

Many combined cycles of this general type are in service or on order. Oil-fired combined cycles with nonreheat steam turbines and unfired or lightly fired boilers are approaching 39% efficiency, and plants on order with higher-temperature gas turbines are expected to exceed 42% efficiency firing clean distillate oil. Figure 6.1 shows the Westinghouse PACE (Power at Combined Efficiency) plant installed at the Comanche Station of Public Service of Oklahoma. It has been in service since early 1974.

6.1.3 Industrial Combined Cycles

The potential for plant efficiency improvements from the combination of a process steam plant with a gas turbine are most attractive to unregulated industrial companies. Gas turbines have been added to produce both electric power and process steam. Industrial companies were quick to adopt the combined cycle concept. For many years the capacity of combined cycles in the service of the petrochemical industry greatly exceeded electrical utility capacity (Reference 6.22).

6.1.4 Combined-Cycle Boilers

Combined cycles which used gas turbines with firing temperatures lower than about 1144°K (1600°F) provided the highest efficiency with boiler firing. The boilers in these plants were similar to conventional boilers for all steam power plants, with the air preheaters replaced by low-temperature economizers. As in conventional boilers, fuel was fired to use 90% of the oxygen in the combustion air (Reference 6.23).

In conventional boilers, maximum heat transfer rates are limited by steam blanketing inside the tubes and by tube metal temperatures. Tube spacing, gas velocities, and furnace volumes are limited by this consideration. With this situation, there is no advantage to be gained from increasing the gas-side surface area of tubes by using an extended surface; conventional boilers use plain tubes, except in some cases where extended surface tubes are used in the cooler regions of economizers.

About 1960, a need developed in industry for boilers to recover the heat from gas turbine exhaust to raise steam for industrial process use. These heat recovery boilers were required to recover heat from exhaust gas between the gas turbine exhaust of 700 to 811°K (800 to 1000°F) and about 422°K (300°F). If the heat recovery boiler is fired, the top temperature may reach 1089°K (1500°F). Traditional boiler designs with bare tubes resulted in a very large tube footage because of the low heat transfer rate on the gas side and the small available log mean temperature difference. Boilers made with bare tubes for this application were, consequently, both large and extremely costly. As a result, some smaller boiler manufacturers developed special boiler designs for this service, using externally finned tubes. The extended surface increases the heat transfer area on the gas-side surface (outside) of the tubes significantly and permits a substantial reduction in the footage of tube required in the boilers (References 6.24 and 6.25). During the 1960s, heat recovery boilers with extended surface were extensively adopted by the chemical process industry. The larger utility boiler manufacturers subsequently adopted extended surface tubes for the low-temperature economizers of combined-cycle boilers.

By 1970, combined cycles with little or no firing of the boilers were on order for midrange utility applications. The low gas temperatures through the boilers favored finned tubes, which are now used throughout the typical combined-cycle boiler.

6.1.5 Current Status of Combined Cycles

The current emphasis on clean fuel for environmental reasons, and the high cost of fuel in general, has placed a premium on efficient power generation. The situation in combined cycles today is similar to that in the 1960s, with the emphasis still on efficiency but with a much higher efficiency required because of the relatively higher cost of fuel.

The higher inlet and outlet temperatures of present-day gas turbines has shifted the optimum combination of gas and steam turbines from fired to unfired boilers. With respect to the steam system, the reheat cycle is the most efficient and economical cycle today, as it was in 1960. The optimum high-efficiency combined cycles of the future will consist of gas turbines exhausting to unfired boilers producing and reheating steam for a reheat steam turbine. Throttle steam pressures will be comparable to conventional fossil fuel plants at about 13.79 MPa (2000 psi) gauge.

To make full recovery of the heat in the gas turbine exhaust at best efficiency, supplementary steam will be raised at lower than throttle pressure, superheated, and inducted into the steam turbine as has been demonstrated in several existing combined cycles. All facets of combined cycles to the above specification have been demonstrated, although with relatively lower steam conditions and smaller equipment size than those suggested for future designs.

6.2 Description of Parametric Points to Be Evaluated

All of the combined-cycle studies were carried out for the exhaust boiler cycle arrangements with the ranges of parametric point values illustrated in Table 6.1. Over 90 parametric points have been identified for investigation of variations in gas turbine, steam turbine, and heat recovery steam generator parameters. Variations of the fuels

FOLDOUT FRAME

Combined Gas-Steam Open Cycle Parametric Points	Gas Turbine Parameters				Steam Turbine Para	
	Turbine Inlet Temperature, °F	Compressor Pressure Ratio	Gas Turbine Cooling	Fuel	St. Turb. Throttle Pressure, psig	St. Turb. Throttle Temperature[3]
Base Case A	2200	12	(See Note 2)	Low-Btu Gas	2400	1000
Base Case B				Dist. from Coal	1250	950
Steam Turbine Parameter Variations					1450	1000
					1450	1000
					1800	1000
Steam Generator Parameter Variations for Base Case A (Duplicate for Base Case B)						
Gas Turbine Parameter Variations for Base Case A (Duplicate for Base Case B)	1800, 2000, 2200, 2400, 2600	8, 12, 16, 20				
Gas Turbine Parameter Variations for Base Case A		8, 12, 16, 20	1, 2, 3			
				High-Btu Gas		
	1800, 2000, 2400			Low-Btu Gas		
		12, 20		Low-Btu Gas		

NOTES:

1. All blank spaces have same value as Base Case A unless otherwise noted
2. Gas turbine blade cooling configurations
   1. Turbine vanes and blades air cooled
   2. Turbine vanes ceramic, blades air cooled
   3. Turbine vanes ceramic, blades ceramic
3. Or as limited by approach temperature
4. Steam induction utilized low temperature heat
5. Supplementary firing for gas turbine inlet temperature 2000°F

FOLDOUT FRAME 2

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Table 6. 1 — Combined gas-steam turbine cycles

...ne Parameters			Steam Generator Parameters									
...Turb. ...rottle ...rature[3],	St. Turb. Reheat Temperature[3],	Condenser Cooling Means	Supplm. Firing	Boiler Gas Side Press. Drop (ΔP/P), %	Evaporator Approach (Pinch), °F	Sphtr. Approach (Pinch), °F	Reheater Approach (Pinch), °F	Press. Drop Drum to Throttle (ΔP/P), %	Press. Drop Reheater Steam (ΔP/P), %	Press. Drop Economizer Water (ΔP/P), %	F.W. Temp. Entering L.T. Econ., °F	Configuration Special Features
00	1000	Wet Tower		5	30	50	50	10	10	10	250	(See Note 4)
50	----							7		7		
00	----											
00	1000											
00	1000											
					15, 40							
				4.6							220, 280	
												Omit Induction
		Once Thru										
		Dry Tower										
			4 Levels									
			Note 5									

(all coal derived) are considered, with principal emphasis placed on two fuels: low-Btu gas and distillate derived from coal. This distinction forms one basis for the identifying two base cases. Base Case A incorporates an integrated, low-Btu gasification plant; Base Case B is fueled by liquid distillate from coal.

Most Base Case A parameters were selected to investigate a moderate, but distinct, extension beyond current state-of-the-art combined-cycle design practice. The gas turbine parameters selected include an inlet temperature of 1478°K (2200°F) and a compressor pressure ratio of 12 to 1, and utilize advanced convection/impingement air-cooled vanes and blades. The steam plant selected utilizes a reheat cycle with steam conditions of 16.547 MPa/811°K/811°K (2400 psig/1000°F/1000°F) and a single low-pressure steam induction (the admission of low-pressure and low-temperature steam into the steam turbine at an appropriate admission point). The heat recovery steam generator is unfired and utilizes parallel superheater and reheater sections followed by HP evaporator, economizer, and LP evaporator sections. The plant utilizes an integrated low-Btu gasification system operating on Illinois No. 6 bituminous coal. The system, patterned after the on-going ERDA Process Demonstration Unit (PDU) program at the Westinghouse Waltz Mill, Pennsylvania site, utilizes a fluidized bed system with in-bed desulfurization. A schematic of the Base Case A cycle arrangement is shown in Figure 6.2.

The Base Case B power plant cycle arrangement is shown in Figure 6.3. This plant differs principally from the Base Case A plant with regard to fuel and steam cycle arrangements. The fuel selected for this plant is a coal-derived distillate from the H-Coal process, and the steam turbine utilizes an 8.610 MPa/783°K (1250 psig/950°F) nonreheat induction design similar to that used in current commercial combined-cycle plants. The heat recovery steam generator arrangement consists of a superheater, HP evaporator, economizer, and LP evaporator with deaerator feedwater system. The gas turbine parameters, with the exception of the fuel, are identical to those of Base Case A.

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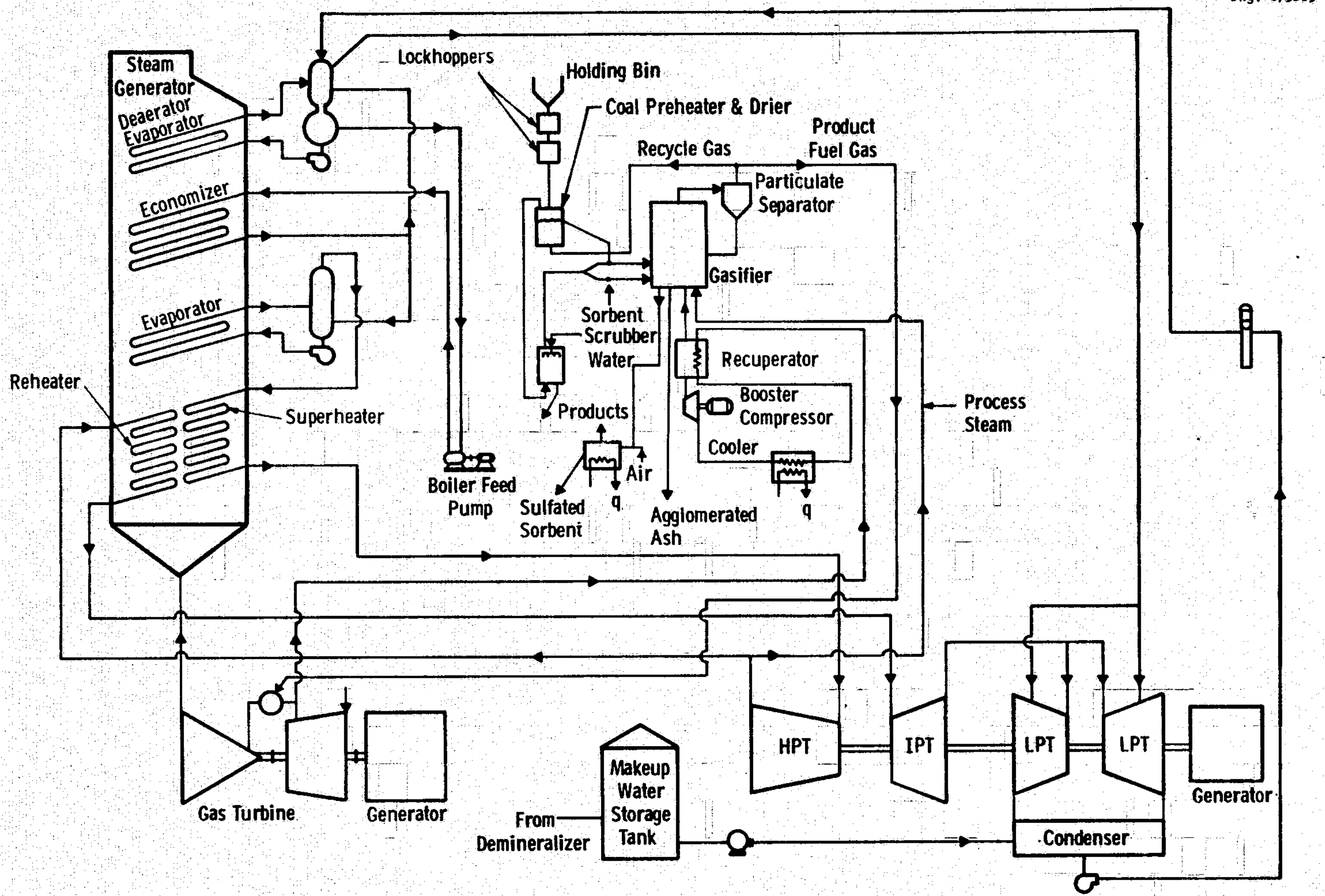

Fig. 6. 2 - Mass and heat balance schematic - Base CaseA - reheat

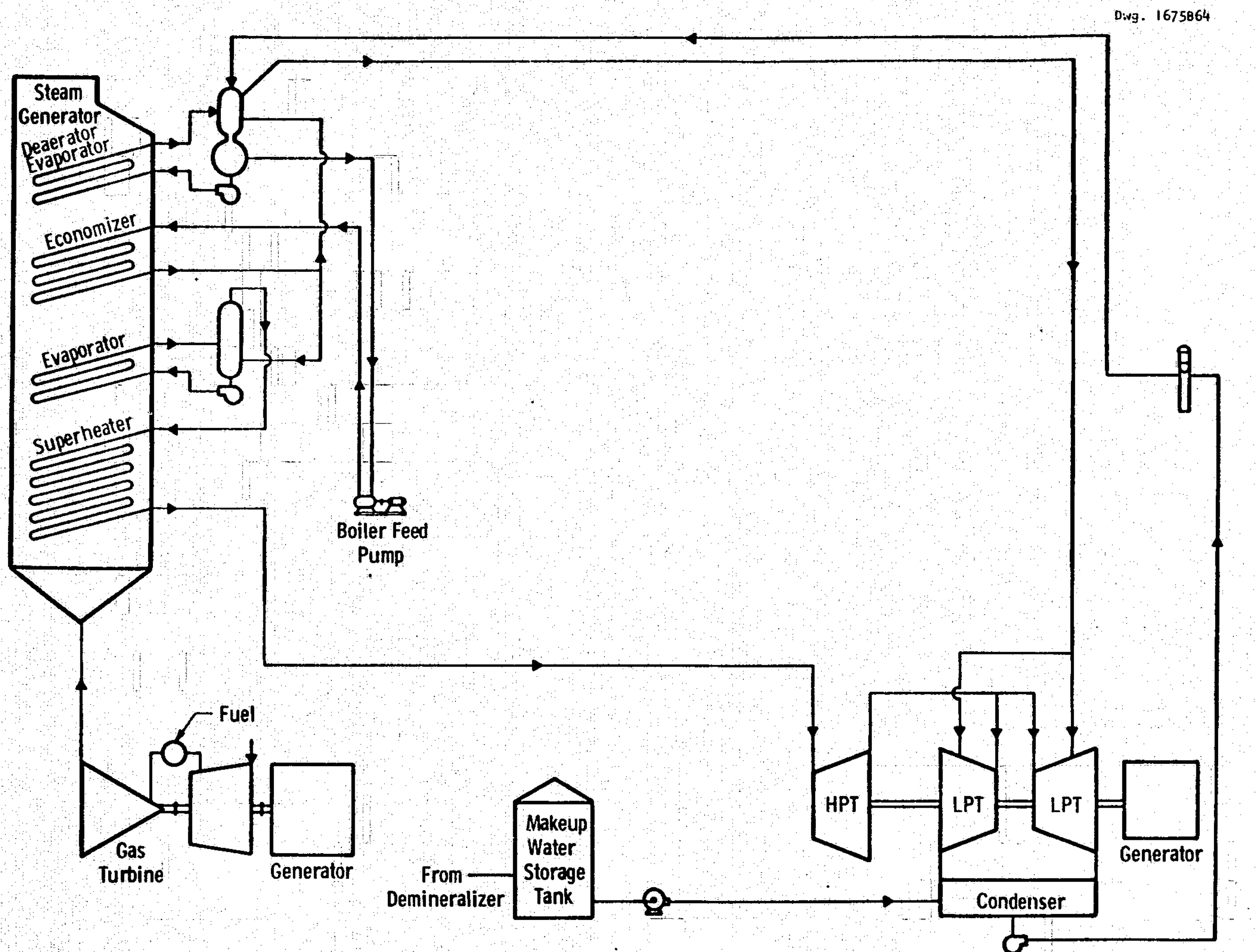

Fig. 6. 3 — Mass and heat balance schematic - Base Case B nonreheat

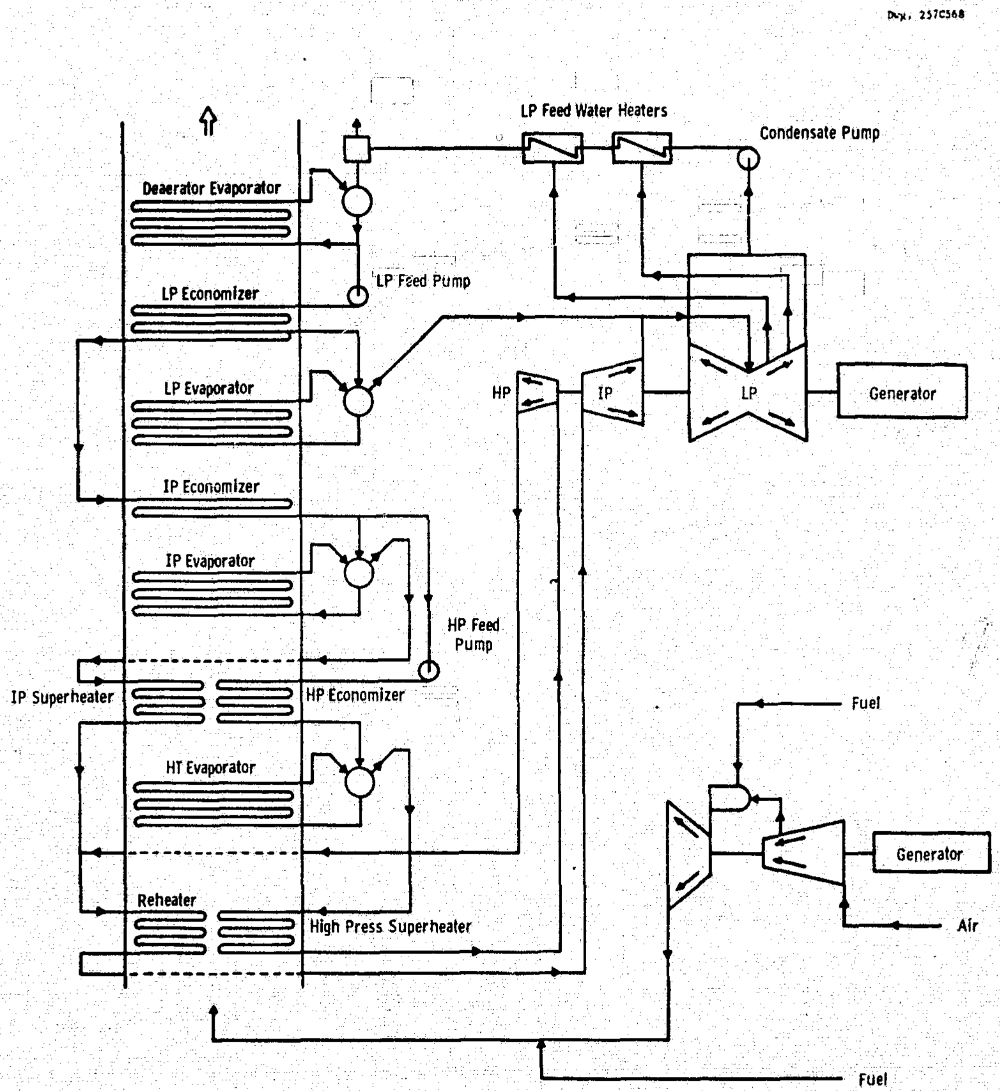

Fig. 6.4—Cycle schematic for generalized steam cycle studies

Additional studies have been identified in the areas of alternative steam turbine throttle conditions, heat recovery steam generator supplementary firing, and steam turbine induction. The general cycle schematic pertaining to these arrangements is given in Figure 6.4. This arrangement is of a general nature and allows for various combinations of feedwater heater arrangements, steam inductions at steam turbine reheat and crossover points, and supplementary firing of the heat recovery steam generator.

As shown in Table 6.1, the parametric point variations have been grouped according to investigations of steam turbine parameter (throttle condition) variations, heat recovery steam generator parameter variations, and gas turbine parameter variations. The alternative steam conditions under consideration, in addition to Base Cases A and B, are 9.997 MPa/811°K (1450 psig/1000°F) nonreheat, and 9.997 MPa/811°K/811°K (1450 psig/1000°F/1000°F) and 12.411 MPa/811°K/811°K (1800 psig/1000°F/1000°F) reheat steam cycle plants.

The steam generator parameter studies have been identified for investigation with both the cycle arrangements of Base Cases A and B. The Base Case A arrangement, however, incorporates an integrated low-Btu gasification system, and the Base Case B arrangement does not. To obtain a uniform basis for comparison, therefore, and to avoid the cumbersome aspect of performing parametric variations with a gasification plant, a modification of Base Case A, designated as Reference Case C, has been defined. This arrangement, shown schematically in Figure 6.5, duplicates the Base Case A arrangement exactly except for omitting the low-Btu gasification system. Using the Reference Case C and Base Case B arrangements, variations of evaporator approach temperature difference have been made from the base case value of 16.7°K (30°F) to 8.3 and 22.2°K (15 and 40°F). Boiler gas-side pressure drop ratios of 4 and 6% have been identified as variations and feedwater temperatures of 378 and 411°K (220 and 280°F) have been set for comparison with the base case value of 394°K (250°F). Heat rejection by means of once-through cooling and dry cooling towers

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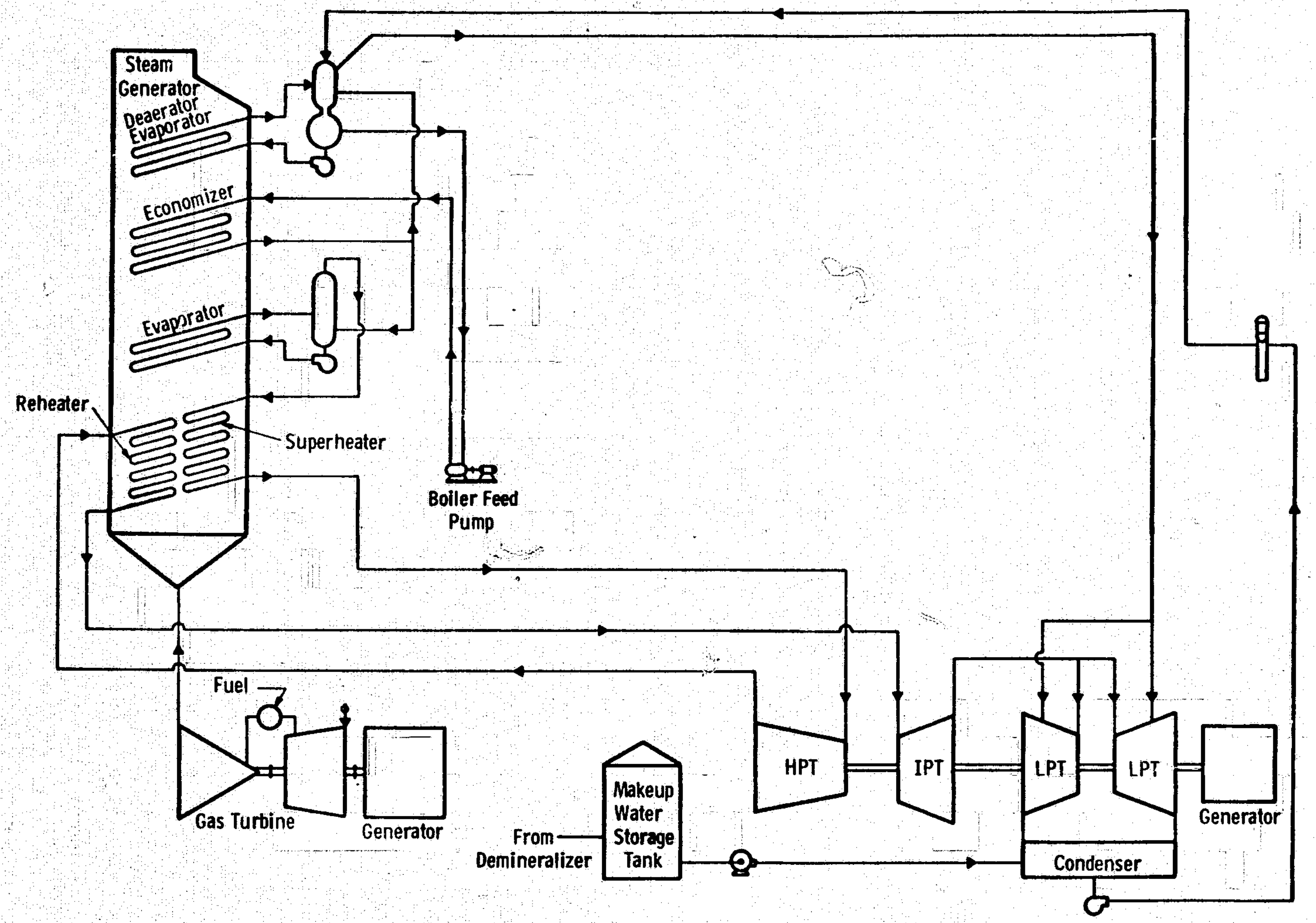

Fig. 6.5 -Mass and heat balance schematic - Reference Case C-reheat

has been selected for comparison with the base case wet tower method. As both Reference Case C and Base Case B include a single, low-pressure steam induction, the omission of this induction for each system has also been set up as a parametric variation.

As mentioned earlier, several additional cases are included (although not shown explicitly on Table 6.1) for a more general study of the use of steam induction. These cases have been set up in conjunction with the cycle model of Figure 6.4. This model has also been identified for use in the investigation of a heat recovery steam generator system with four-level supplementary firing for both the reheat and nonreheat steam cycle arrangements.

The gas turbine parameter variations identified in Table 6.1 for study with both Base Case A (Reference Case C arrangement) and Base Case B include both turbine inlet temperature and compressor pressure ratio. Turbine inlet temperature values of 1255, 1366, 1478, 1589, and 1700°K (1800, 2000, 2200, 2400, and 2600°F) have been identified for study. Compressor pressure ratios of 8, 12, 16, and 20 have been selected. In all cases advanced impingement and convection air-cooled blades and vanes are assumed.

The final category of parametric variations identified in Table 6.1 applies to the variation of gas turbine parameters of Base Case A for the reheat steam cycle only. In this category are included variations of gas turbine blade-cooling systems, including the use of ceramic gas turbine vanes and rotating blades alone and in combination. Parametric variations of these cooling systems have been selected with variations in compressor pressure ratio from 8 to 20 at a constant turbine inlet temperature of 1478°K (2200°F). The use of high-Btu coal-derived fuel gas has been identified for a system calculation in addition to the low-Btu gas and clean distillate from coal-burning systems. Variations of the low-Btu gasification plant have been identified for study with a variation in turbine inlet temperature from 1255 to 1589°K (1800 to 2400°F) at the base case compressor pressure ratio of 12 to 1.

6.3 Approach

As with the recuperated open-cycle system described in Section 5 of this report, most of the parametric point efficiency calculations for the gas-steam combined cycles were performed using the Westinghouse-developed OPTCYC computer program. Essentially, the same assumptions are made regarding calculation of the gas turbine portion of the combined cycle. These include specification of ambient conditions, compressor efficiency, gas turbine section cooling-flow usage, and the coal-derived distillate fuel properties.

Following calculation of the gas turbine performance, the combined-cycle part of the program next performs a mass and energy balance between gas turbine exhaust gas and each heat exchanger in the heat recovery steam generator (refer to Figures 6.2 and 6.3). This system consists of a deaerator, low-pressure boiler, economizer, evaporator, superheater, and reheater (the latter is bypassed for a nonreheat cycle). Boiler feedwater heating is accomplished by the single deaerator receiving heat from the low-pressure boiler as well as from the economizer recirculation. Additional heat is obtained by extracting steam from the low-pressure steam turbine, if necessary. On the other hand, excess low-pressure steam can be inducted into the LP steam turbine to produce power. The program uses expansion lines of actual steam turbines to calculate performance. Thus, moisture content, exhaust loss, and end loading are all properly considered. With the steam flow and enthalpy known, the steam turbine power is computed and added to the gas turbine power. The net output of the combined plant is obtained after deducting mechanical and generator losses as well as plant auxiliary power requirements. The auxiliary power includes such items as boiler feed pump, circulating pumps, lube and fuel pumps, and cooling tower fan power. Based on the higher heating value of the fuel, combined plant efficiency is calculated and displayed against combined plant specific power based on compressor inlet airflow.

When a low-Btu gas fuel is used, the gasification subsystem is integrated by satisfying the specified characteristics of the gasification system. As mentioned earlier, the Westinghouse Advanced Fluidized Bed process, currently being developed under ERDA contract, was assumed for this purpose. Process steam is extracted from cold reheat point after the HP steam turbine, and process air is bled from the combustor shell. It acquires a higher pressure, dictated by the gasification system pressure drop, via a booster compressor. A recuperator is used to alleviate the duties of the cooler and the booster compressor and raise the temperature of the process air before it enters the gasifier. In this case, the auxiliary power further includes the booster compressor power as well as all auxiliaries in the gasification system. Similarly, the heat from the spent sorbent oxidizer and cooler are recovered through the steam turbine and feed heating. Thus, the net combined plant efficiency represents the overall conversion of coal feed to electricity.

As indicated in Section 5.1, although current production dry-type combustors (that is, combustors not utilizing water injection techniques) will pose potential problems with regard to NO_x emissions at high turbine inlet temperature burning conventional fuels, Task I calculations were performed without water injection for NO_x control. There are two reasons for this choice. First, we believe that several advanced combustion concepts (staged, premixed, and catalytic combustion) with proper development effort will yield satisfactory operation on conventional-type fuels without water injection. Second, the principal fuel under consideration (the coal-derived distillate from the H-coal process) has properties very similar to conventional petroleum-based distillate fuel. For combustion of low-Btu gas, calculations have indicated the NO_x problem to be potentially much less severe than with distillate fuels.

For the cases involving steam induction, various assumptions were made regarding induction steam condition and the location of induction into the steam turbine. For the base case steam cycle conditions, induction steam was generated at the deaerator pressure of 207 kPa (30 psi) abs and inducted through a special supply manifold at this pressure. In the cases of induction at the reheater and at the crossover pipe between the IP and LP steam turbines, no special manifold is required.

The quantities of induction steam were obtained by heat balance between the gas-side exits from the induction steam evaporator and the next higher evaporator. For given assumptions of steam conditions and approach temperatures, there is a unique solution for the HP and induction steam quantities.

The feedwater temperature leaving the closed heaters and entering the deaerator is established by a heat balance below the LP evaporator which results in a gas temperature entering the stack of 411°K (280°F) and a water temperature entering the economizer of 394°K (250°F).

Variations of supplementary firing in the heat recovery steam generator covered the range from no firing to the maximum for efficient combustion with the oxygen in the vitiated exhaust of the gas turbine.

Supplementary firing increases the proportion of available heat in the boiler above the saturation temperature of the steam and, therefore, the quantity of high-pressure steam. At a supplementary firing temperature of 1033°K (1400°F), the feedwater for the high-pressure steam absorbs all the heat available below the evaporator and no heat remains to generate induction steam. The first level of boiler firing was selected at the point where no induction steam is generated.

Firing to a higher temperature results in a deficiency of heat in the economizer, which would result in a reduced feedwater temperature rise. This deficiency is corrected by heating a portion of the feedwater in a train of extraction feedwater heaters, as shown in the general calculation model, Figure 6.4. The maximum level of supplementary firing investigated was the case of 10% excess air. In this case, 35% of the feedwater is heated by the stack gas in a low economizer, and 65% of the feedwater is heated in the extraction feedwater heaters. An intermediate level of boiler firing is calculated where the quantities of feedwater heated by extraction steam and flue gas were about equal.

Definitions regarding gas turbine parameters and assumed values are identical to those (with the exception of recuperator and intercooler definitions) described in Section 5.3 of this report. For the additional combined-cycle components, typical component efficiencies, loss values, and auxiliary power requirements consistent with current Westinghouse design practice have been used.

Additional definitions pertaining to the steam section of the combined gas-steam cycle are as follows:

- Steam turbine throttle pressure - nominal steam pressure at the main turbine stop valve
- Steam turbine throttle temperature - nominal steam temperature at the main turbine stop valve
- Steam turbine reheat temperature - nominal steam temperature at the intermediate pressure (IP) turbine inlet section
- Boiler gas-side pressure drop - exhaust gas pressure drop from gas turbine section outlet to heat recovery steam generator exhaust
- Evaporator approach temperature difference - minimum temperature difference between exhaust gas stream and high-pressure steam saturation temperature
- Superheater approach temperature difference - temperature difference between gas turbine exhaust temperature and maximum superheater steam temperature
- Reheater approach temperature difference - temperature difference between gas turbine exhaust temperature and maximum reheated steam temperature
- Pressure drop drum to throttle - pressure drop between heat recovery steam generator high-pressure steam drum and steam turbine throttle pressure

- Pressure drop (feedheater) - pressure drop between condensate pump and deaerator section
- Pressure drop (economizer water) - pressure drop between boiler feed pump and steam drum
- Induction - the process of introducing reduced pressure steam into the steam turbine at a location downstream of the main stop valve.

6.4 Results of the Parametric Study

An expanded form of the parametric point tabulation is given in Table 6.2. In this listing the parametric points are numbered for convenient reference and cover the ranges of values of the parameters identified in the summary Table 6.1.

Point 1 applies to Base Case A, and Point 2 corresponds to Base Case B. In Points 3, 4, and 5 the effects of varying steam throttle conditions are considered. Point 6, originally specified as a supercritical 24.132 MPa/811°K/811°K/811°K (3500 psig/1000°F/1000°F/1000°F), was not calculated. Variations of steam generator and steam turbine parameters, including approach temperature differences, feedwater temperature, and omission of the single low-pressure steam induction, were computed for a Base Case A-type reheat steam cycle in Points 7 through 13. The alternative heat rejection modes of once-through and dry-tower cooling are used in conjunction with the reheat-type steam bottoming plant in Points 14 and 15, respectively. The use of supplementary firing of the heat recovery steam generator has been investigated for Points 16 through 19. These studies apply to the reheat steam bottoming cycle with multiple induction, as was shown in Figure 6.4. The parametric variations of Points 20 through 32 are directly analogous to the Points 7 through 19 variations, with the only distinction being that they apply to the nonreheat-type steam bottoming cycle of Base Case B shown in Figure 6.3.

For Points 33 through 52, attention is again given to the reheat steam bottoming cycle, and parametric variations are performed on the gas

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TABLE 6.2 — GAS STEAM COMBINED CYCLE
Base Case A, Point 1; Base Case B, Point 2

Sheet 1 of 5

Parametric Point	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Power Output, MWe																		
Fuel																		
Distillate		X	X	X	X		X	X	X	X	X	X	X	X	X	X	X	X
High-Btu Gas																		
Low-Btu Gas	X																	
Gas Turbine																		
Inlet Temp., °F	2200	2200	2200	2200	2200		2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200
Pressure Ratio	12	12	12	12	12		12	12	12	12	12	12	12	12	12	12	12	12
Cooling (1)	(a)	(a)	(a)	(a)	(a)		(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)
Steam Turbine																		
Throttle Press., psig	2400	1250	1450	1450	1800		2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400
Throttle Temp., °F (2)	1000	950	1000	1000	1000		1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
First Reheat Temp., °F (2)	1000			1000	1000		1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Second Reheat Temp., °F (2)																		
Heat Rejection						Not Calculated												
Wet Tower	X	X	X	X	X		X	X	X	X	X	X	X			X	X	X
Dry Tower															X			
Once Through														X				
Supplementary Firing (level) (3)	No	No	No	No	No		No	No	No	No	No	No	No	No	No	No	2nd	3 rd
Steam Generator																		
Pressure Drop ΔP/P, %																		
Gas Side	5	5	5	5	5		5	5	4	6	5	5	5	5	5	5	5	5
Drum to Throttle	10	7	7	10	10		10	10	10	10	10	10	10	10	10	10	10	10
Reheater	10			10	10		10	10	10	10	10	10	10	10	10	10	10	10
Economizer	10	7	7	10	10		10	10	10	10	10	10	10	10	10	10	10	10
Pinch Point ΔT, °F																		
Evaporator	30	30	30	30	30		15	40	30	30	30	30	30	30	30	30	30	30
Superheater	50	50	50	50	50		50	50	50	50	50	50	50	50	50	50	50	50
Reheater	50			50	50		50	50	50	50	50	50	50	50	50	50	50	50
Feed Water Temp., °F	250	250	250	250	250		250	250	250	250	220	280	250	250	250	250	250	250
Special Features	(4)	(4)	(5)	(6)	(6)		(4)	(4)	(4)	(4)	(4)	(4)		(4)	(4)	(6)		(7)

Notes:

(1) Gas Turbine Blade Cooling Configurations
- (a) Turbine Vanes & Blades Air Cooled
- (b) Vanes Ceramic, Blades Air Cooled
- (c) Vanes Ceramic, Blades Ceramic
- (d) Vanes Ceramic, Blades Water Cooled

(2) Or as Limited by Approach Temp.

(3) Supplementary Firing Level
- 2nd Level 1430°F
- 3rd Level 2410°F
- 4th Level 3260°F

(4) Steam Induction Utilizes Low Temp. Heat, 30psia Steam Induction into LP Turbine

(5) Steam Induction into Crossover Pipe

(6) Steam Induction into Cold Reheat Pipe and Crossover Pipe

(7) Extraction Feedwater Heating

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TABLE 6.2 – GAS STEAM COMBINED CYCLE (CONT'D.)

Sheet 2 of 5

Parametric Point	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
Power Output, MWe																		
Fuel																		
Distillate	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
High-Btu Gas																		
Low-Btu Gas																		
Gas Turbine																		
Inlet Temp., °F	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	1800	1800	1800	1800
Pressure Ratio	12	12	12	12	12	12	12	12	12	12	12	12	12	12	8	12	16	20
Cooling ①	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ
Steam Turbine																		
Throttle Press., psig	2400	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	2400	2400	2400	2400
Throttle Temp., °F ②	1000	950	950	950	950	950	950	950	950	950	950	950	950	950	1000	1000	1000	1000
First Reheat Temp., °F ②	1000														1000	1000	1000	1000
Second Reheat Temp., °F ②																		
Heat Rejection																		
Wet Tower	X	X	X	X	X	X	X	X			X	X	X	X	X	X	X	X
Dry Tower										X								
Once Through									X									
Supplementary Firing (level) ③	4th	No	No	No	No	No	No	No	No	No	No	2nd	3rd	4th	No	No	No	No
Steam Generator																		
Pressure Drop ΔP/P, %																		
Gas Side	5	5	5	4	6	5	5	5	5	5	5	5	5	5	5	5	5	5
Drum to Throttle	10	7	7	7	7	7	7	7	7	7	7	7	7	7	10	10	10	10
Reheater	10														10	10	10	10
Economizer	10	7	7	7	7	7	7	7	7	7	7	7	7	7	10	10	10	10
Pinch Point ΔT, °F																		
Evaporator	30	15	40	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Superheater	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Reheater	50														50	50	50	50
Feed Water Temp., °F	250	250	250	250	250	220	280	250	250	250	250	250	250	250	250	250	250	250
Special Features	⑦	④	④	④	④	④	④		④	④	⑤				④	④	④	④

Notes:

① Gas Turbine Blade Cooling Configurations
- ⓐ Turbine Vanes & Blades Air Cooled
- ⓑ Vanes Ceramic, Blades Air Cooled
- ⓒ Vanes Ceramic, Blades Ceramic
- ⓓ Vanes Ceramic, Blades Water Cooled

② Or as Limited by Approach Temp.

③ Supplementary Firing Level
- 2nd Level 1430°F
- 3rd Level 2410°F
- 4th Level 3260°F

④ Steam Induction Utilizes Low Temp. Heat, 30psia Steam Induction into LP Turbine

⑤ Steam Induction into Crossover Pipe

⑦ Extraction Feedwater Heating

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TABLE 6.2 – GAS STEAM COMBINED CYCLE (CONT'D.)
Reference Case C, Point 42

Sheet 3 of 5

Parametric Point	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
Power Output, MWe																		
Fuel																		
Distillate	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
High-Btu Gas																		
Low-Btu Gas																		
Gas Turbine																		
Inlet Temp., °F	2000	2000	2000	2000	2200	2200	2200	2200	2400	2400	2400	2400	2600	2600	2600	2600	1800	1800
Pressure Ratio	8	12	16	20	8	12	16	20	8	12	16	20	8	12	16	20	8	12
Cooling ①	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ
Steam Turbine																		
Throttle Press., psig	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	1250	1250
Throttle Temp., °F ②	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	950	950
First Reheat Temp., °F ②	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000		
Second Reheat Temp., °F ②																		
Heat Rejection																		
Wet Tower	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Dry Tower																		
Once Through																		
Supplementary Firing (level)	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Steam Generator																		
Pressure Drop $\Delta P/P$, %																		
Gas Side	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Drum to Throttle	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	7	7
Reheater	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10		
Economizer	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	7	7
Pinch Point ΔT, °F																		
Evaporator	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Superheater	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Reheater	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50		
Feed Water Temp., °F	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Special Features	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④

Notes:

① Gas Turbine Blade Cooling Configurations
- ⓐ Turbine Vanes & Blades Air Cooled
- ⓑ Vanes Ceramic, Blades Air Cooled
- ⓒ Vanes Ceramic, Blades Ceramic
- ⓓ Vanes Ceramic, Blades Water Cooled

② Or as Limited by Approach Temp.

④ Steam Induction Utilizes Low Temp. Heat, 30psia Steam Induction into LP Turbine

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TABLE 6.2 – GAS STEAM COMBINED CYCLE (CONT' D.)

Sheet 4 of 5

Parametric Point	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72
Power Output, MWe																		
Fuel																		
Distillate	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
High-Btu Gas																		
Low-Btu Gas																		
Gas Turbine																		
Inlet Temp., °F	1800	1800	2000	2000	2000	2000	2200	2200	2200	2400	2400	2400	2400	2600	2600	2600	2600	2200
Pressure Ratio	16	20	8	12	16	20	8	16	20	8	16	16	20	8	12	16	20	8
Cooling ①	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓐ	ⓑ
Steam Turbine																		
Throttle Press., psig	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	2400
Throttle Temp., °F ②	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950	1000
First Reheat Temp., °F ②																		1000
Second Reheat Temp., °F ②																		
Heat Rejection																		
Wet Tower	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Dry Tower																		
Once Through																		
Supplementary Firing (level)	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Steam Generator																		
Pressure Drop ΔP/P, %																		
Gas Side	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Drum to Throttle	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	10
Reheater																		10
Economizer	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	10
Pinch Point ΔT, °F																		
Evaporator	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Superheater	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Reheater																		50
Feed Water Temp., °F	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Special Features	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④	④

Notes:

① Gas Turbine Blade Cooling Configurations
- ⓐ Turbine Vanes & Blades Air Cooled
- ⓑ Vanes Ceramic, Blades Air Cooled
- ⓒ Vanes Ceramic, Blades Ceramic
- ⓓ Vanes Ceramic, Blades Water Cooled

② Or as Limited by Appraoch Temp.

④ Steam Induction Utilizes Low Temp. Heat, 30psia Steam Induction into LP Turbine

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TABLE 6.2 – GAS STEAM COMBINED CYCLE* (CONT' D.)

* Points 85, 86 and 87 were not costed

Sheet 5 of 5

Parametric Point	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91
Power Output, MWe																			
Fuel																			
Distillate	X	X	X	X	X	X	X										X	X	X
High-Btu Gas												X							
Low-Btu Gas													X	X	X				
Gas Turbine																			
Inlet Temp., °F	2200	2200	2200	2200	2200	2200	2200					2200	2000	2400	1800		2200	2200	2200
Pressure Ratio	12	16	20	8	12	16	20					12	12	12	12		12	12	12
Cooling ①	ⓑ	ⓑ	ⓑ	ⓒ	ⓒ	ⓒ	ⓒ					ⓐ	ⓐ	ⓐ	ⓐ		ⓐ	ⓐ	ⓐ
Steam Turbine																			
Throttle Press., psig	2400	2400	2400	2400	2400	2400	2400					2400	2400	2400	2400		2400	2400	2400
Throttle Temp., °F ②	1000	1000	1000	1000	1000	1000	1000					1000	1000	1000	1000		1000	1000	1000
First Reheat Temp., °F ②	1000	1000	1000	1000	1000	1000	1000					1000	1000	1000	1000		1000	1000	1000
Second Reheat Temp., °F ②																			
Heat Rejection									Not Calculated										
Wet Tower	X	X	X	X	X	X	X					X	X	X	X		X	X	X
Dry Tower																			
Once Through																			
Supplementary Firing (level)	No	No	No	No	No	No	No					No	No	No	No		No	No	No
Steam Generator																			
Pressure Drop ΔP/P, %																			
Gas Side	5	5	5	5	5	5	5					5	5	5	5		5	5	5
Drum to Throttle	10	10	10	10	10	10	10					10	10	10	10		10	10	10
Reheater	10	10	10	10	10	10	10					10	10	10	10		10	10	10
Economizer	10	10	10	10	10	10	10					10	10	10	10		10	10	10
Pinch Point ΔT, °F																			
Evaporator	30	30	30	30	30	30	30					30	30	30	30		30	30	30
Superheater	50	50	50	50	50	50	50					50	50	50	50		50	50	50
Reheater	50	50	50	50	50	50	50					50	50	50	50		50	50	50
Feed Water Temp., °F	250	250	250	250	250	250	250					250	250	250	250		250	250	250
Special Features	④	④	④	④	④	④	④					④	④	④	④		⑧	⑥	

Notes:

① Gas Turbine Blade Cooling Configurations
- ⓐ Turbine Vanes & Blades Air Cooled
- ⓑ Vanes Ceramic, Blades Air Cooled
- ⓒ Vanes Ceramic, Baldes Ceramic
- ⓓ Vanes Ceramic, Blades Water Cooled

④ Steam Induction Utilizes Low Temp. Heat, 30psia Steam Induction into LP Turbine

⑥ Induction into the Crossover Pipe

⑧ Induction into Cold Reheat Pipe

turbine parameters of turbine inlet temperature and compressor pressure ratio. For these calculations, turbine inlet temperature has been varied from 1255 to 1700°K (1800 to 2600°F), and compressor pressure ratio variations span the range of 8 through 20 to 1. Distillate fuel from coal and impingement, convection cooling for gas turbine vanes and blades are specified for these calculations. The same combinations of turbine inlet temperature, compressor pressure ratios, fuel, and cooling are investigated in Points 53 through 71 with the Base Case B-type nonreheat steam bottoming cycle.

Several calculations have been identified next for investigating the effects of variation in the type of gas turbine blade-cooling systems. These calculations have been identified for use with the reheat-type steam bottoming cycle and assume the coal-derived distillate as fuel. Points 72 through 75 are calculated at a gas turbine inlet temperature 1478°K (2200°F) with compressor pressure ratios varying from 8 through 20. For these calculations, ceramic vanes and air-cooled rotor blades are assumed. Points 76 through 79 are identical, with the exception that both ceramic vanes and ceramic rotating blades are specified. The combination of ceramic vanes and water-cooled blades, originally identified for Points 80 through 83, were not calculated. Coal-derived high-Btu gas has been substituted for the liquid coal-derived distillate as the fuel in Point 84.

Points 85 through 88 were originally specified for a parametric investigation of integrated low-Btu gasification cycles, with variations in both gas turbine compressor pressure ratio and turbine inlet temperature. These cases were later simplified, and the calculations of efficiency only were performed by modifying Base Case A solely to reflect the effect of alternative turbine inlet temperatures of 1255, 1366, and 1589°K (1800, 2000, and 2400°F).

Variations in the use of steam induction were investigated in Points 89, 90, and 91. These studies were based on the general cycle arrangement shown in Figure 6.4. A single steam induction was utilized at the steam turbine reheat point for Point 89, while Point 90 utilized a single steam induction at the crossover line between the intermediate-pressure (IP) and low-pressure (LP) steam turbine elements. Point 91 utilizes neither of these steam inductions.

6.4.1 Selected Case Results

A summary of calculated performance data for Base Case A is presented as Figure 6.6, where the data point station numbers refer to the cycle schematic (Figure 6.2) which is repeated here for the convenience of the reader. The overall efficiency (coal to bus bar) for this plant has been calculated to be well in excess of 40%, including the gasification process. A turbine inlet temperature of 1478°K (2200°F) and a compressor pressure ratio of 12 to 1 were used in the calculation, and the fuel was Illinois No. 6 bituminous coal.

Figure 6.7 summarizes the calculated cycle data and plant performance for Base Case B, as defined in Point 2. As in Base Case A, this plant utilizes gas turbine parameters of a 1478°K (2200°F) turbine inlet temperature and a compressor pressure ratio of 12 to 1. This plant, however, is fired with coal-derived distillate fuel. The calculated thermodynamic efficiency for the Base Case B power plant is greater than 45%.

The Reference Case C (Point 42) plant arrangement is, with the exception of the substitution of coal-derived distillate fuel for the gasification process, the same as Base Case A. Summary thermodynamic results for this case are given on Figure 6.8.

Special studies were made of the effect of steam turbine induction on the overall plant performance. A representative example of this analysis is given by Point 16 which incorporates steam induction at both the steam turbine reheat and crossover points. Summary cycle calculation results are given on Figure 6.9. The calculated thermodynamic efficiency for this case is approximately 48%.

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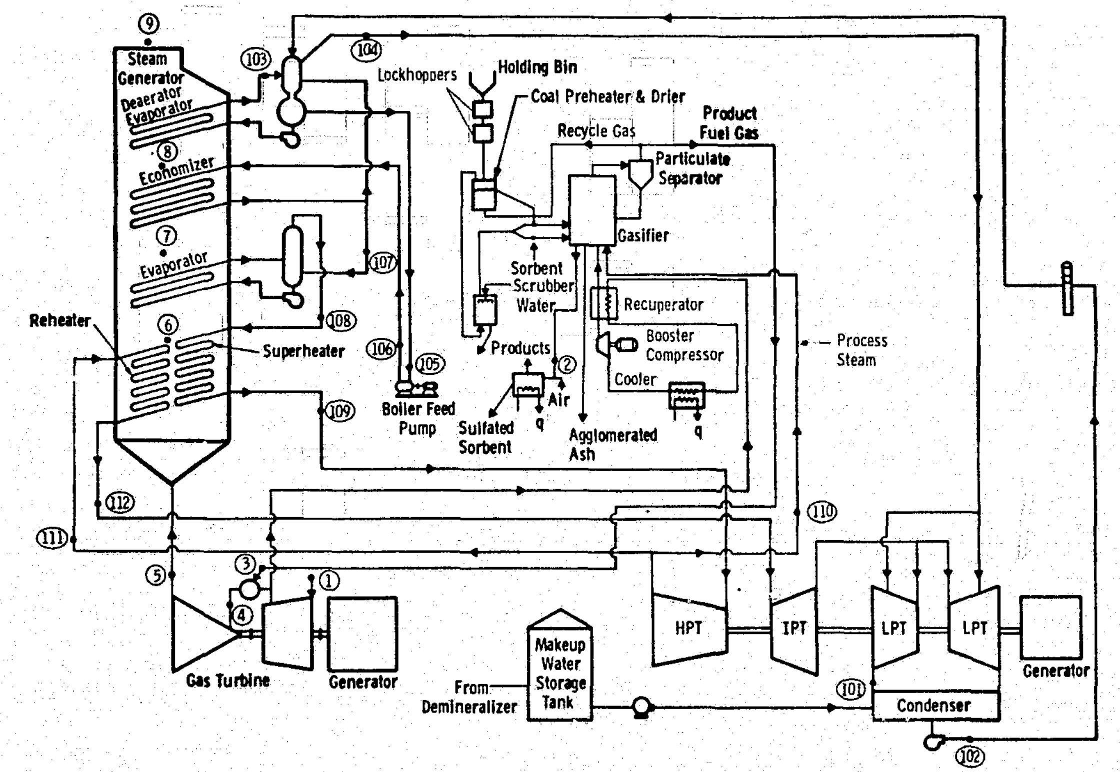

Station	Pressure, psia	Temperature, °F	Enthalpy, Btu/lb	Flow, lb/s
Gas Turbine, Gasifier, and HRSG				
1	14.696	59		936.4
2		600		103.4
3		1600		153.5
4	165.4	2200		
5	15.4	1057	288.7	1014.0
6		839	228.9	
7		709	194.0	
8		472	132.5	
9	14.696	290	86.4	
Steam Cycle				
101	2 in Hg Abs		1009.5	
102		101	69.1	139.1
103				48.6
104	30	250		32.8
105	30	250		106.3
106	2980			
107	2683	673	742.0	106.3
108		678	1070.0	
109	2415	1000	1461.2	106.3
110				18.6
111	556	630	1321.7	87.7
112	500	1000	1519.6	87.7

Fig. 6.6—Base Case A cycle data summary (Point 1)

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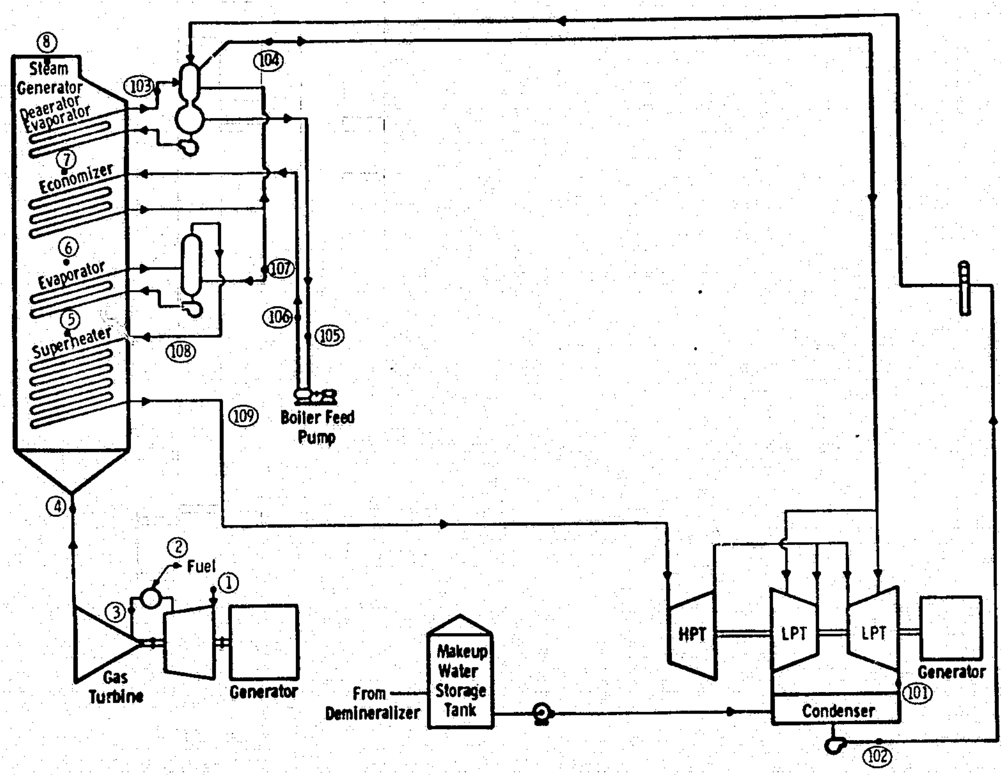
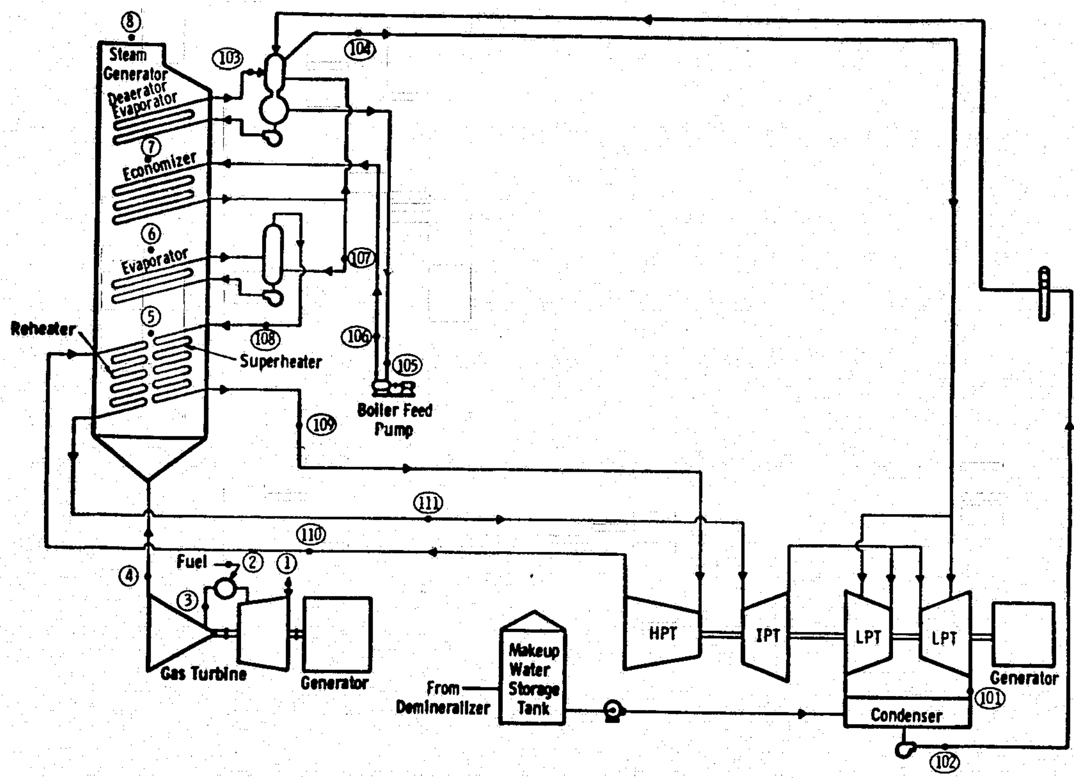


Station	Pressure, psia	Temperature, °F	Enthalpy, Btu/lb	Flow, lb/s
Gas Turbine and HRSG				
1	14.696	59		963.40
2				21.30
3	165.4	2200		
4		1042	281.7	984.70
5		903	243.9	
6		608	166.1	
7		405	114.1	
8		290	85.7	
Steam Cycle				
101	2 in Hg Abs			
102		101	69.1	138.50
103				29.48
104	30	250		12.64
105	30	250		138.50
106	1385			
107	1304	573	578.8	125.90
108		578	1178.3	
109	1213	950	1469.9	125.90

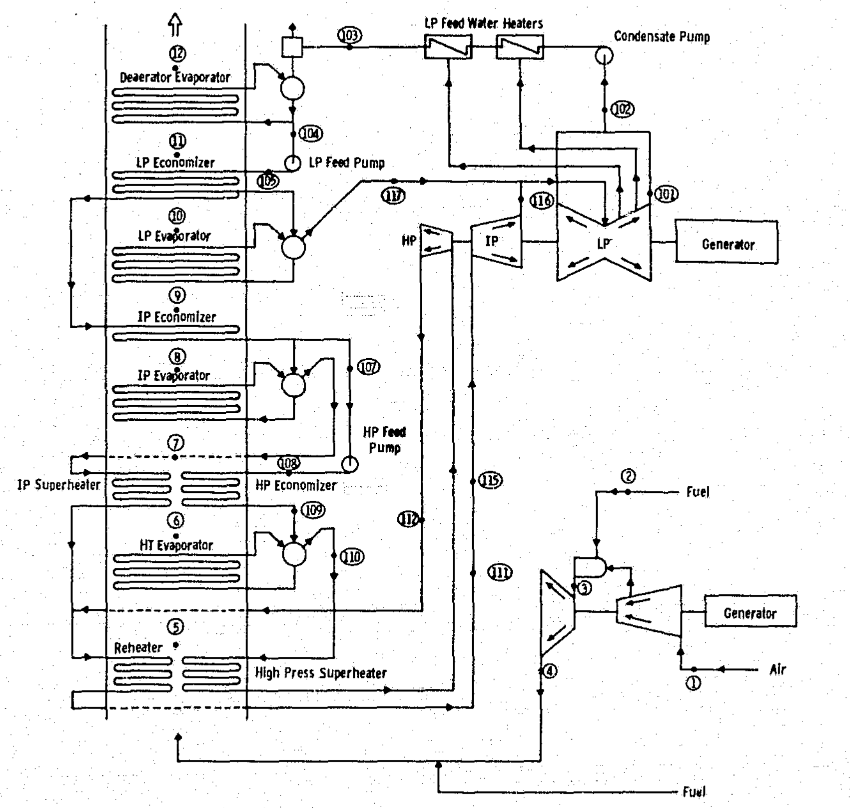
Fig 6.7—Base Case B cycle data summary (Point 2)

Dwg. 257C565



Station	Pressure, psia	Temperature, °F	Enthalpy, Btu/lb	Flow, lb/s
Gas Turbine and HRSG				
1	14.696	59		963.40
2				21.30
3	165.4	2200		
4		1042	281.7	984.70
5		832	225.0	
6		705	191.2	
7		489	135.8	
8	14.696	290	85.7	
Steam Cycle				
101	2 in Hg Abs			
102		101	69.1	130.70
103				51.30
104	30	250		36.10
105	30	250		104.10
106	2900			
107	2610	670	733.5	94.60
108		675	1079.0	
109	2350	992	1458.2	94.60
110	556	630	1312.8	
111	500	992	1515.4	94.60

Fig. 6.8 – Reference Case C cycle data summary (Point 42)



Station	Pressure, psia	Temperature, °F	Enthalpy, Btu/lb	Flow, lb/s
<u>Gas Turbine and HRSG</u>				
1	14.696	59		963.40
2				21.30
3	165.700	2200		984.70
4	15.700	1042	375.7	
5		820	316.3	
6		709	287.1	
7		600	259.4	
8		522	239.0	
9		447	220.9	
10		387	205.6	
11		337	193.0	
12	14.696	278	178.1	
<u>Steam Cycle</u>				
101	2 In Hg Abs	101	1014.0	134.90
102		101	69.0	135.80
103	35	159	127.0	135.80
104	29	248	216.0	135.80
105	707	250	220.0	135.80
106	147	357	329.0	135.80
107	636	492	480.0	118.50
108	2981	503	491.2	90.63
109	2683	679	755.0	90.63
110	2683	679	1072.0	90.63
111	2500	1000	1460.4	90.63
112	604	647	1320.0	89.72
113	636	492	1203.0	27.85
114	604	647	1320.0	27.85
115	543	1000	1518.0	117.60
116	140	667	1360.0	117.60
117	147	357	1164.0	17.34

Fig. 6.9 —Induction study: Induction at steam turbine reheat & crossover points

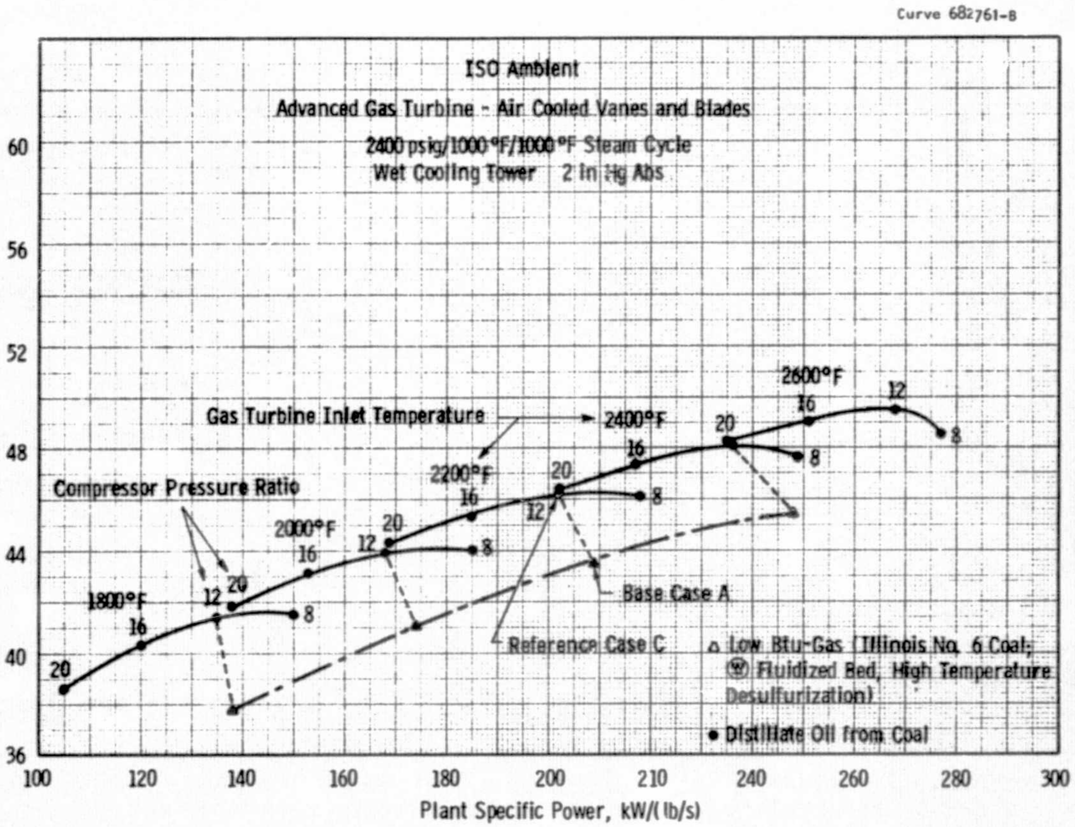


Fig. 6.10—Combined cycle plant performance

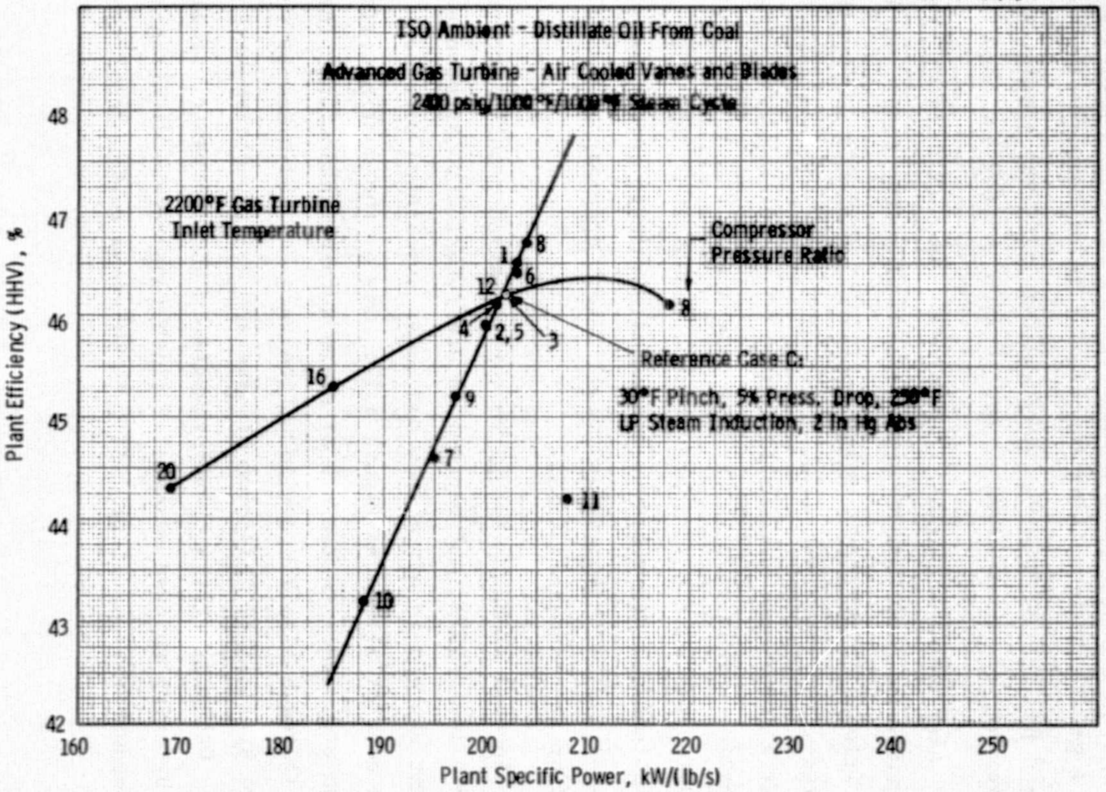
6.4.2 Results of Parametric Variations

Figure 6.10 displays the results of turbine inlet temperature and compressor pressure ratio variation on the basic reheat steam cycle, Reference Case C. Curves of plant efficiency versus specific power are plotted at constant inlet temperature. These results show the general improvement in performance with increasing the turbine inlet temperature and, further, that the optimum (maximum efficiency) pressure ratio is a gradually increasing function of inlet temperature. At 1255°K (1800°F), a peak efficiency of approximately 41.6% was obtained, while a peak efficiency of about 49.6% occurs at 1700°K (2600°F).

Also shown in Figure 6.10 are the plant efficiency results corresponding to the gasification combined-cycle Base Case A and three additional integrated low-Btu gasification plants calculated for gas turbine inlet temperatures of 1589, 1366, and 1255°K (2400, 2000, and 1800°F) at a compressor pressure ratio of 12 to 1. Comparing the gasification combined-cycle results of Base Case A with the distillate fuel-burning Reference Case C indicates that although the combined plant efficiency is decreased by approximately 5% in going from distillate fuel to coal gasification, the combined plant specific power is increased by approximately 4.5%.

Several steam system parameter variation results are reported in Figure 6.11. Again, all variations are referred to Reference Case C. The percent changes in efficiency and power associated with each variation have been displayed in Figure 6.12. One of the most powerful single effects on efficiency is the use of steam turbine induction. (Reference Case C utilized a single steam induction into the low-pressure turbine. Other more specialized induction studies are described elsewhere in this section.) Other significant improvements in thermodynamic efficiency are obtained by using reduced evaporator pinch temperature difference, increased feedwater temperature, and reduced steam turbine condenser pressure.

Curve 682763-B



1 – Evaporator Pinch = 15°F
2 – Evaporator Pinch = 40°F
3 – Boiler Exhaust Press. Drop = 4%
4 – Boiler Exhaust Press. Drop = 6%
5 – FW Temperature = 220°F
6 – FW Temperature = 280°F
7 – Omit Induction
8 – Condenser Pressure = 1.5 in Hg Abs
9 – Condenser Pressure = 3.5 in Hg Abs
10 – Condenser Pressure = 9 in Hg Abs
11 – High-Btu Gas Fuel

Fig. 6.11 – Effect of various parameter changes on plant performance

Curve 679890-B

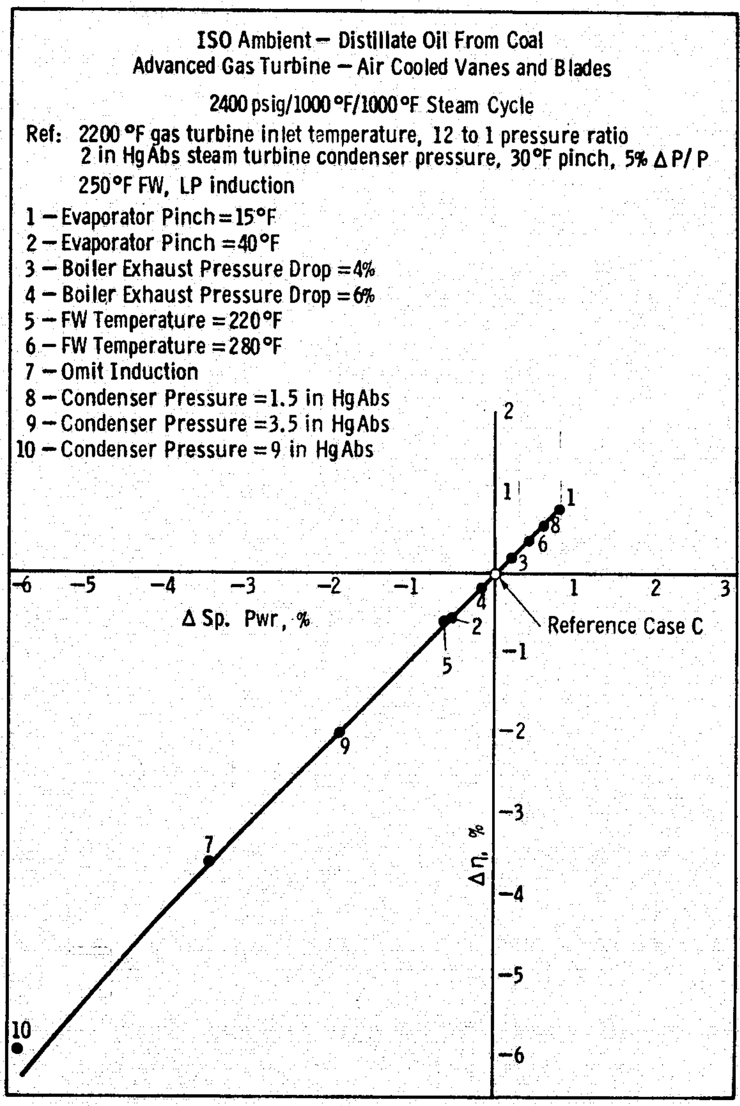


Fig. 6. 12–Effect of various parameter changes on combined plant performance

Curve 679889-B

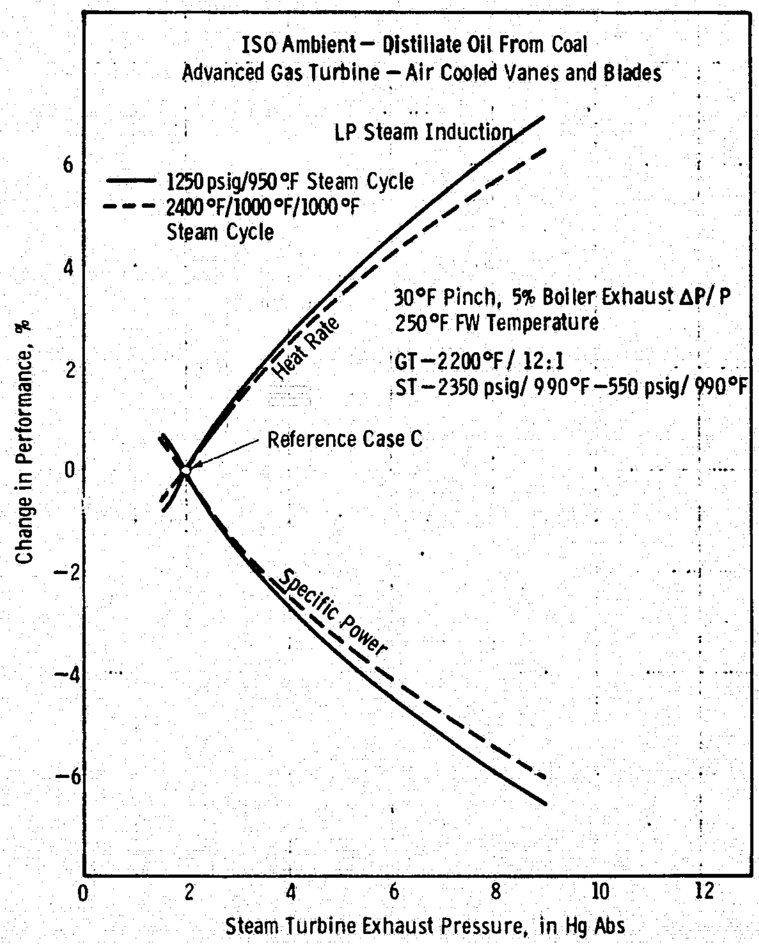


Fig.6. 13 —Effect of steam turbine condenser pressure on combined plant performance

Special attention was given the subject of the effect of steam turbine exhaust pressure on overall power plant performance. The curves in Figure 6.13 summarize the results of varying this quantity from its nominal value as used in the Reference Case C configuration. In going from the nominal 6.77 kPa (2 in Hg) abs back pressure associated with the use of wet cooling towers to the 5.08 kPa (1.5 in Hg) abs value, achievable using once-through cooling, the combined plant heat rate and specific power are improved by approximately 0.6% each.

The use of ceramic gas turbine vanes and blades has been investigated as a means of improving combined-cycle performance as a consequence of the minimization of cooling air expenditure. Two levels of implementation have been considered: the use of ceramic stationary vanes in conjunction with air-cooled rotating blades, and the use of both ceramic stationary vanes and ceramic rotating blades. The results of the study are shown in Figure 6.14. In comparison with Reference Case C, the parametric point using both ceramic vanes and ceramic blades at a compressor pressure ratio of 12 to 1 showed an improvement of nearly 6% in heat rate and an increase of nearly 19% in combined plant output.

The results shown on Figures 6.15 through 6.17 are based on variations of the nonreheat steam cycle, Base Case B (Point 2). They compare directly with the parametric variations reported in Figures 6.10 through 6.12 described above, which were based on the reheat steam cycle Reference Case C.

Direct comparisons between the results of calculations with reheat bottoming cycles and nonreheat bottoming cycles are presented in Figures 6.18 and 6.19. The first comparison at 1478°K (2200°F) shows the reheat cycle with superior efficiency for compressor pressures of 8 to 16 and the nonreheat cycle efficiency slightly higher for higher pressure ratios. Figure 6.19 shows the reheat steam cycle to have a higher efficiency over the entire compressor pressure ratio range investigated at a turbine inlet temperature of 1700°K (2600°F).

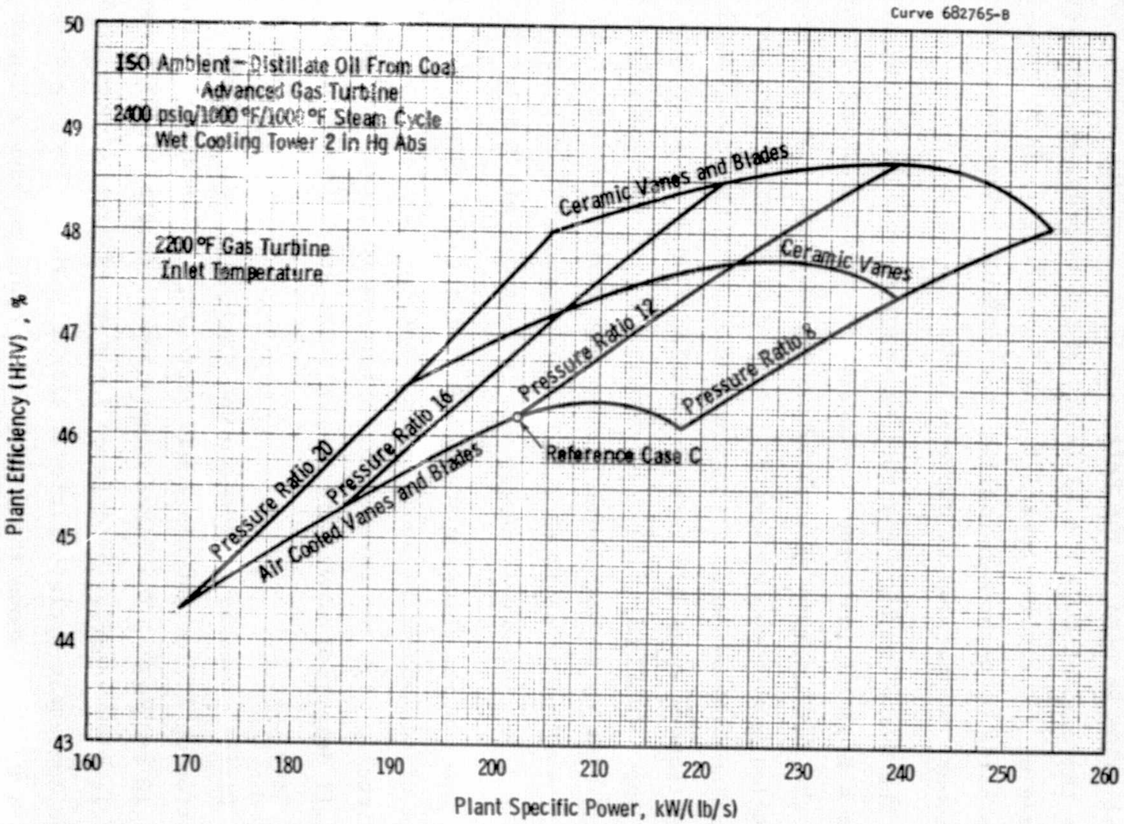


Fig. 6.14—Effect of gas turbine blading material on plant performance

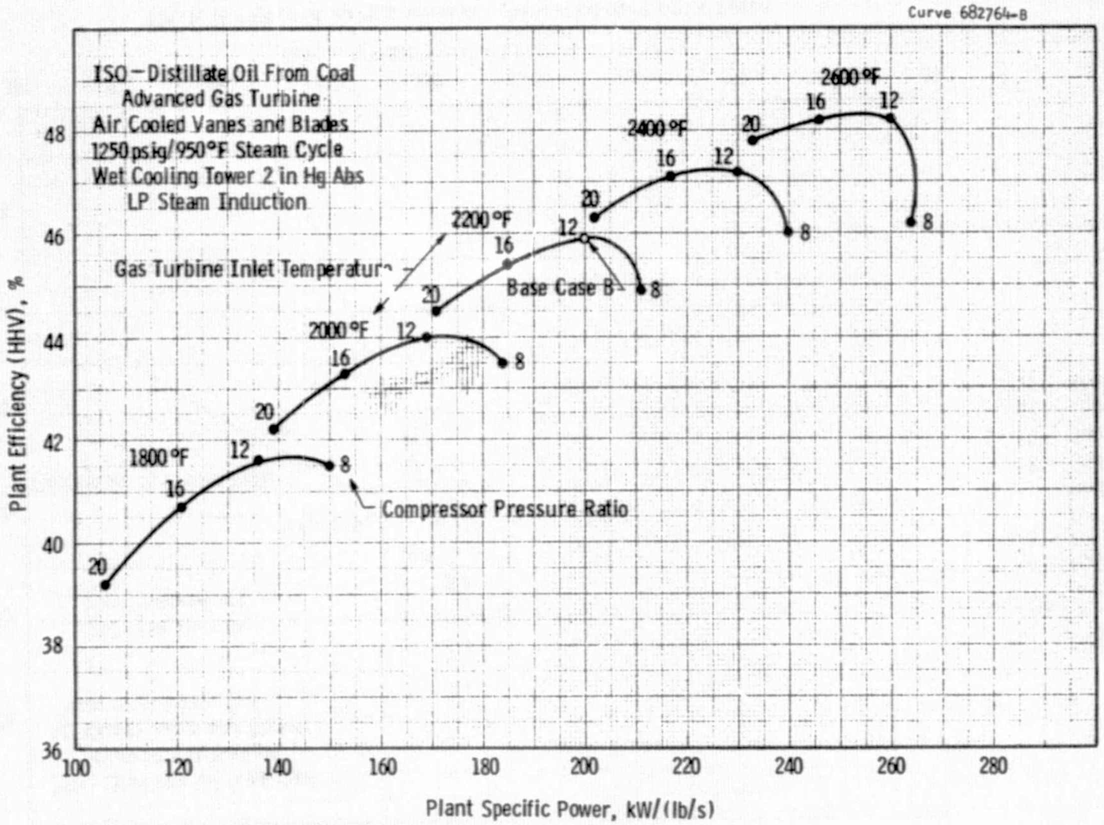


Fig. 6.15—Combined plant performance

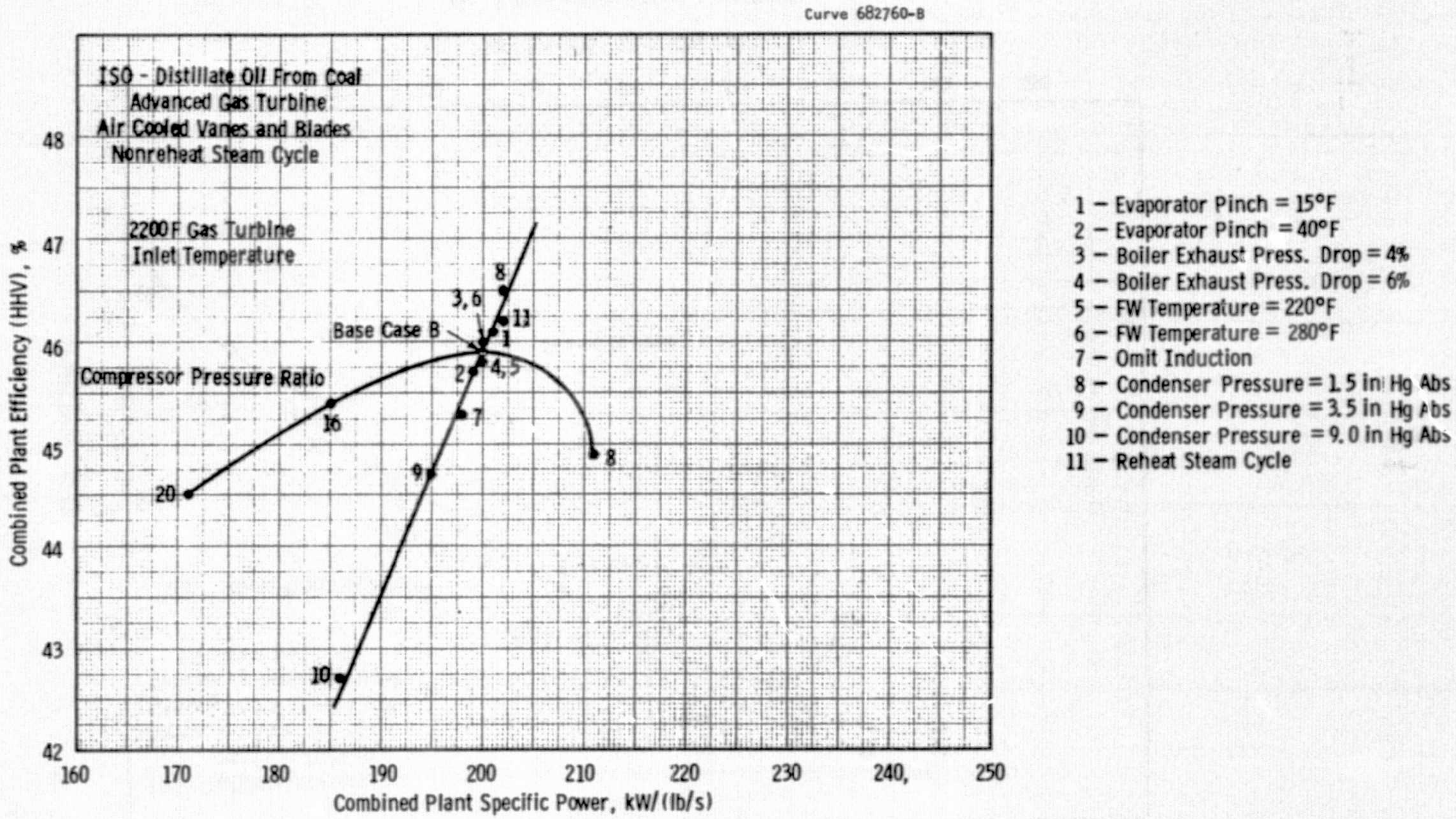


Fig. 6.16 – Effect of various parameter changes on plant performance

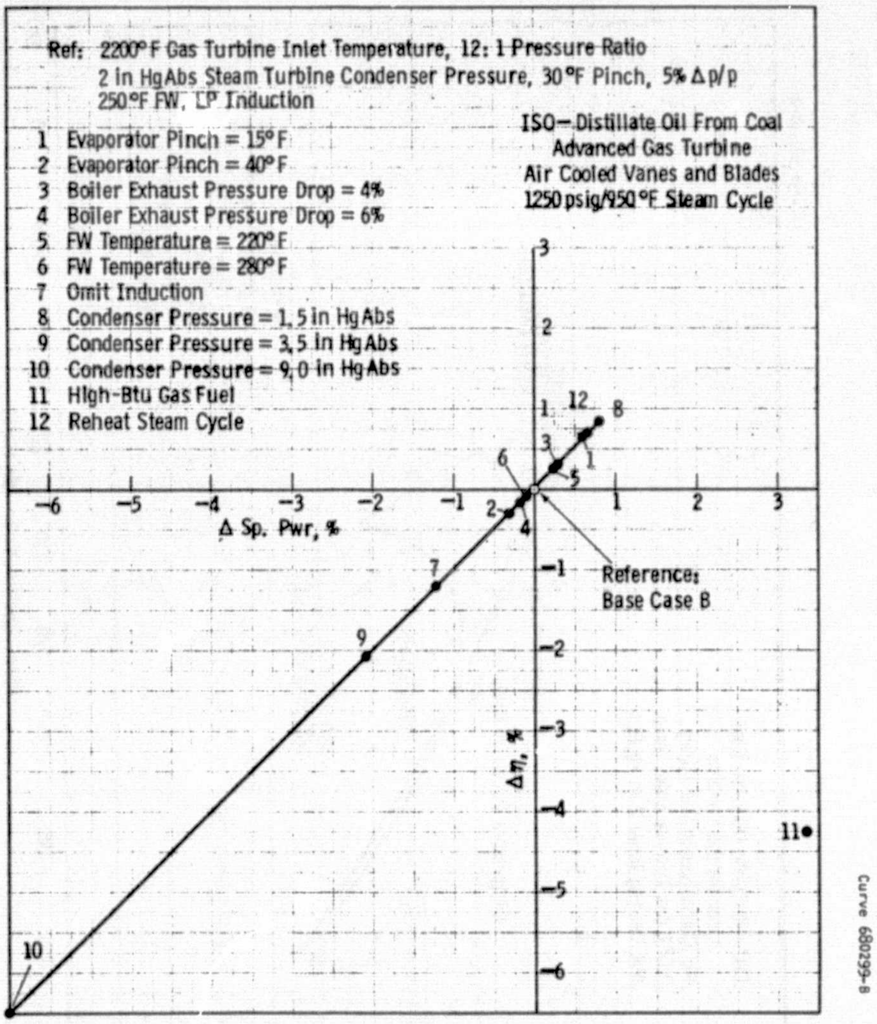


Fig. 6. 17— Effect of various parameter changes on combined plant performance

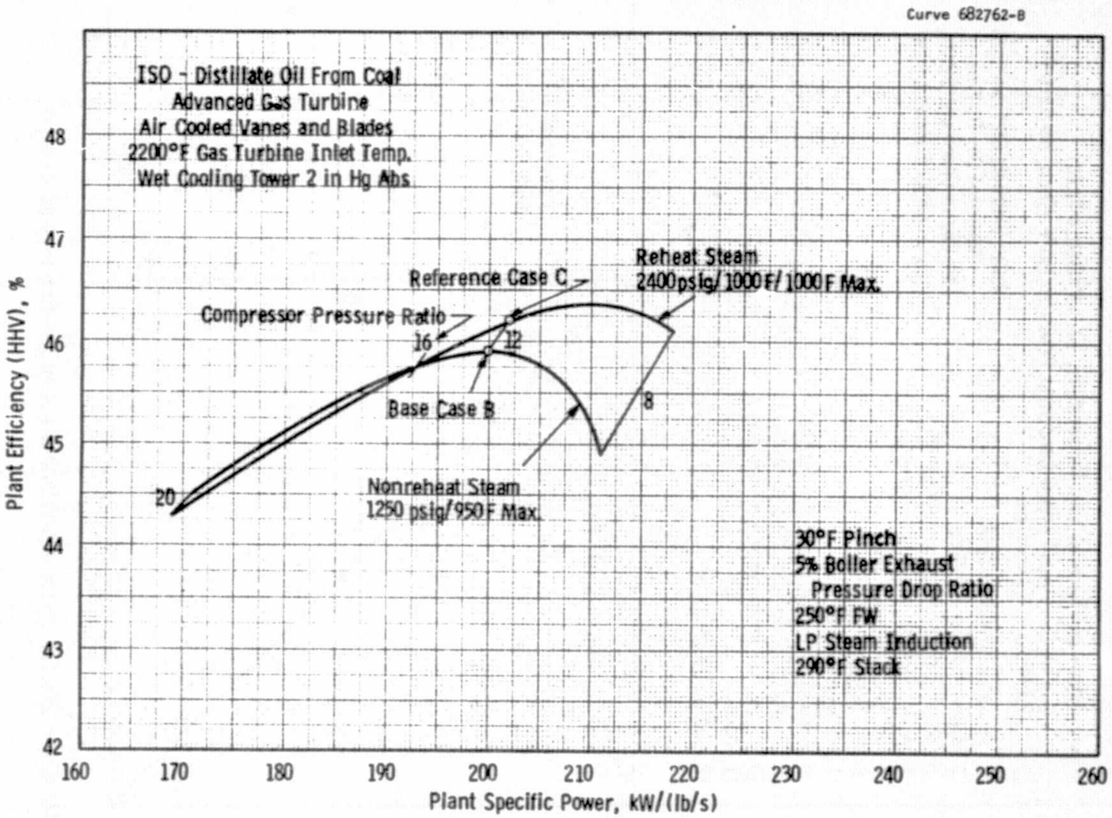


Fig. 6.18 —Effect of reheat steam cycle on plant performance

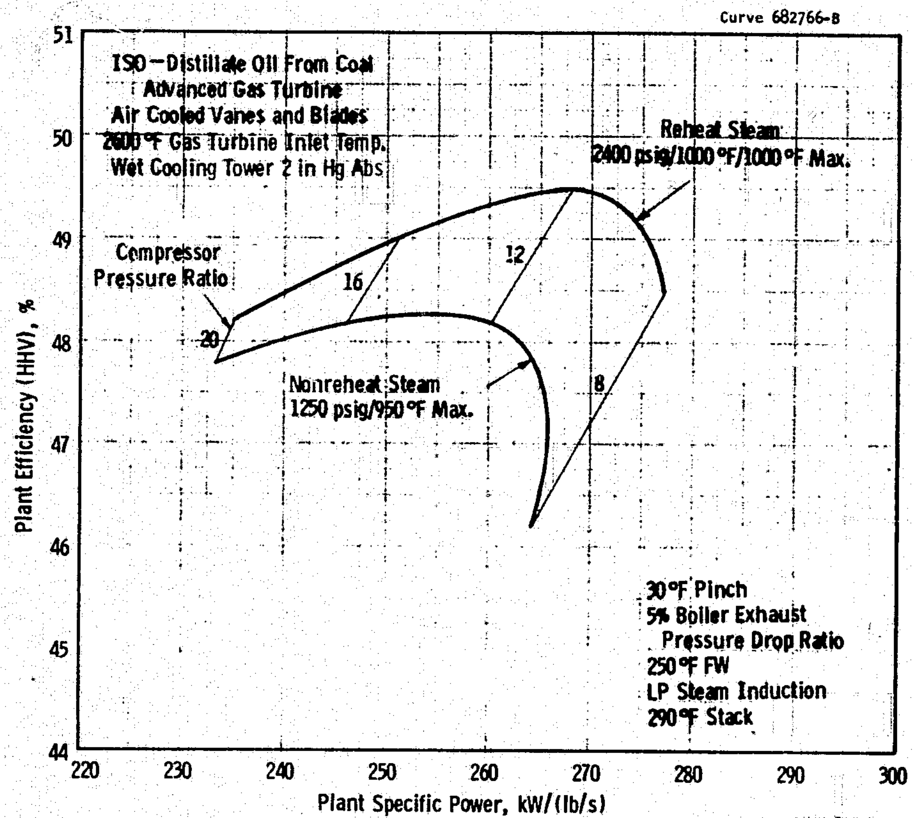


Fig. 6.19 – Effect of reheat steam cycle on plant performance

Curve 680294-B

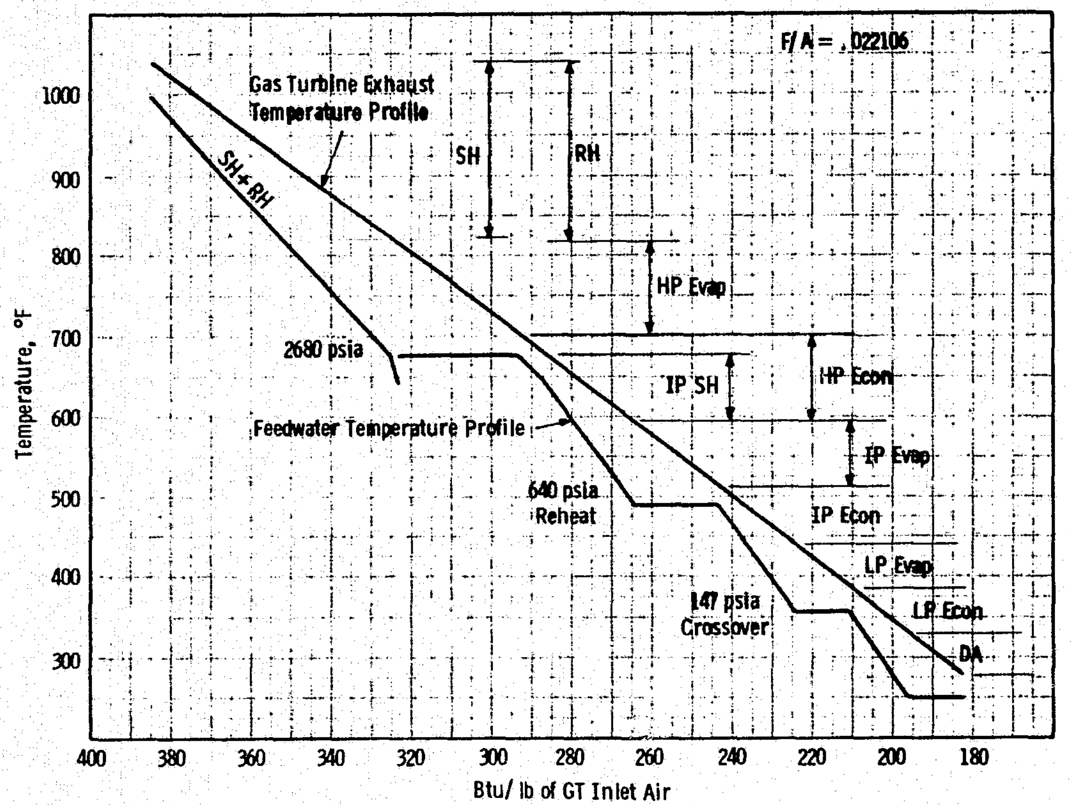


Fig. 6. 20 — 2400/ 1000/ 1000 Boiler temperature profile with reheat crossover induction

The parametric cycle study work described heretofore was performed in accordance with the base case cycle schematic models given in Figures 6.2, 6.3, and 6.5. These cycles incorporate the induction of steam at low pressures into the steam turbine LP element, and they incorporate both reheat and nonreheat steam turbine bottoming cycles. The special studies performed to consider the application of supplementary fired steam boilers, alternative steam pressure levels, and additional variations on the use of steam induction were based on the generalized cycle model shown in Figure 6.4. One of the principal objectives of incorporating steam induction was to improve the thermodynamic fit between the gas turbine exhaust heat rejection line and the steam cycle heat acceptance line. (The concept of thermodynamic fit is discussed more fully in Section 7 of this report.) Figure 6.20 displays the fit resulting from the analysis of Point 16, which incorporates steam induction at both the reheat and crossover points. The efficiency for this cycle, as compared to the others incorporating no inductions, and one or two inductions at various steam cycle throttle conditions is illustrated in Figure 6.21. For the general arrangement of Point 16 [16.547 MPa/811°K/811°K (2400 psig/1000°F/1000°F) Unfired Boiler], power plant efficiency can be increased from approximately 45% to nearly 48% by adding two steam inductions.

6.5 Capital and Installation Cost of Plant Components

6.5.1 Description of Base Case Power Plants

Development of plant capital costs for the gas-steam combined cycle concept was based upon detailed examination of the base case plants with appropriate variations for the remaining parametric points.

Base Case A consists of an integrated low-Btu gasification combined-cycle plant with four gas turbines whose waste heat is used to generate steam for a single reheat steam turbine. The Base Case B arrangement is made up of two distillate fuel-fired gas turbines exhausting into waste heat recovery boilers, whose output is used to drive a single nonreheat steam turbine.

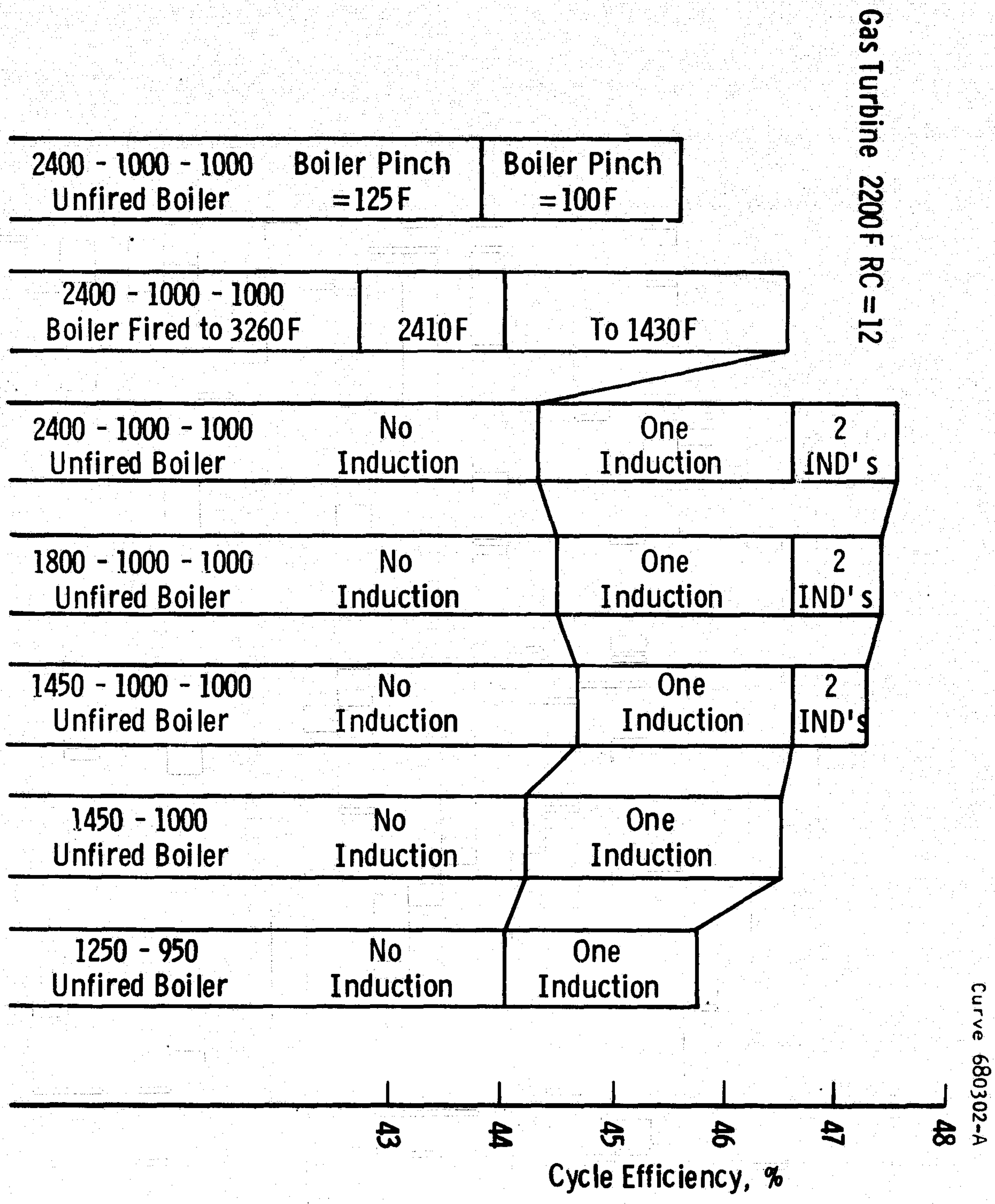


Fig. 6.21 – Combined cycle efficiencies

The plant island arrangement for Base Case A is illustrated in Figure 6.22. The overall site arrangement is shown in Figure 6.23. Four nominal 130 MWe gas turbines individually exhaust into unfired heat recovery steam generators which provide steam for a nominal 16.547 MPa/811°K/811°K (2400 psig/1000°F/1000°F) steam turbine. The gas turbines receive fuel gas from a pressurized fluid bed gasification system utilizing in-bed fuel gas desulfurization.

Figure 6.24 illustrates the gas turbine concept design selected for the Base Case A application. The single-shaft design passes 440 kg/s (970 lb/s) at 60 rps (3600 rpm). A multiple-can burner system capable of firing either low-Btu gas fuel or liquid distillate-type fuel is included in this design. The three-stage turbine uses conventional metal blading with vanes and blades cooled by impingement, convection, and film-cooling techniques using air as the coolant medium. Two tilting pad film-type journal bearings support the shaft, with thrust loads taken up by a tilting pad segmented thrust bearing at the compressor end of the shaft. The generator drive is at the cold compressor end of the shaft, which facilitates the use of a low-loss axial-flow turbine exhaust diffuser and the positioning of in-line heat recovery equipment. The casing features horizontal joint construction for easy access, and can be shipped by rail fully assembled. The exciter and hydrogen-cooled generator are directly coupled to the gas turbine shaft. The starting package, which is electrically operated, drives through the exciter and generator shafting to provide rotation and acceleration to self-sustaining speed. Gas turbine auxiliary support services are provided by individual skid-mounted assemblies, shown in place on Figure 6.22. The mechanical skid assembly includes lubricating oil pumps, filters, and reservoir; an air system pressure switch and gauge cabinet; and seal oil system. Included in the electrical and control skid is the battery equipment, motor control center, voltage regulator, generator relay panel, and certain control equipment. The fuel skid includes fuel pumps, filters, and related equipment.

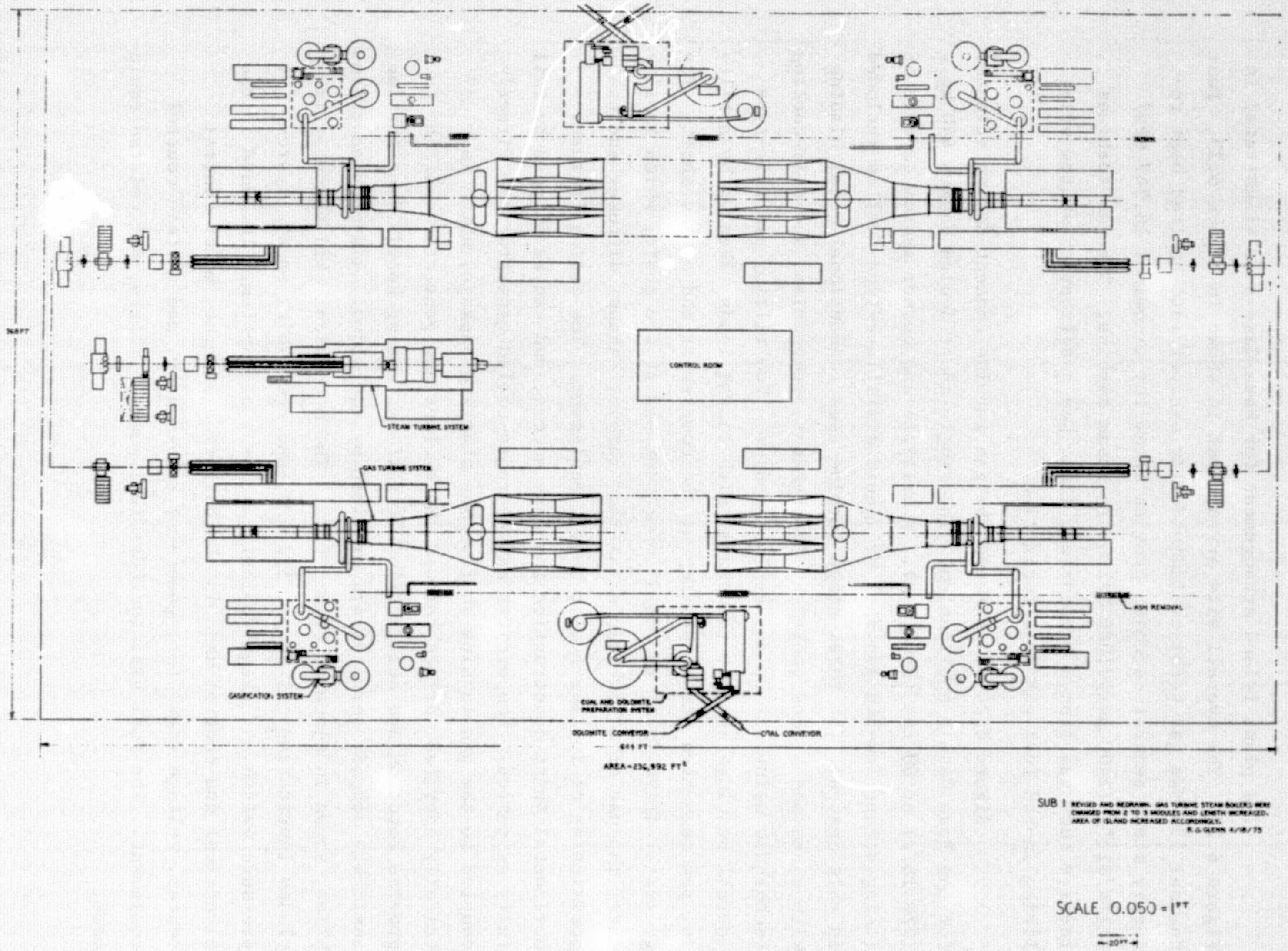


Fig. 6.22—Combined-cycle power plant island - Base Case A

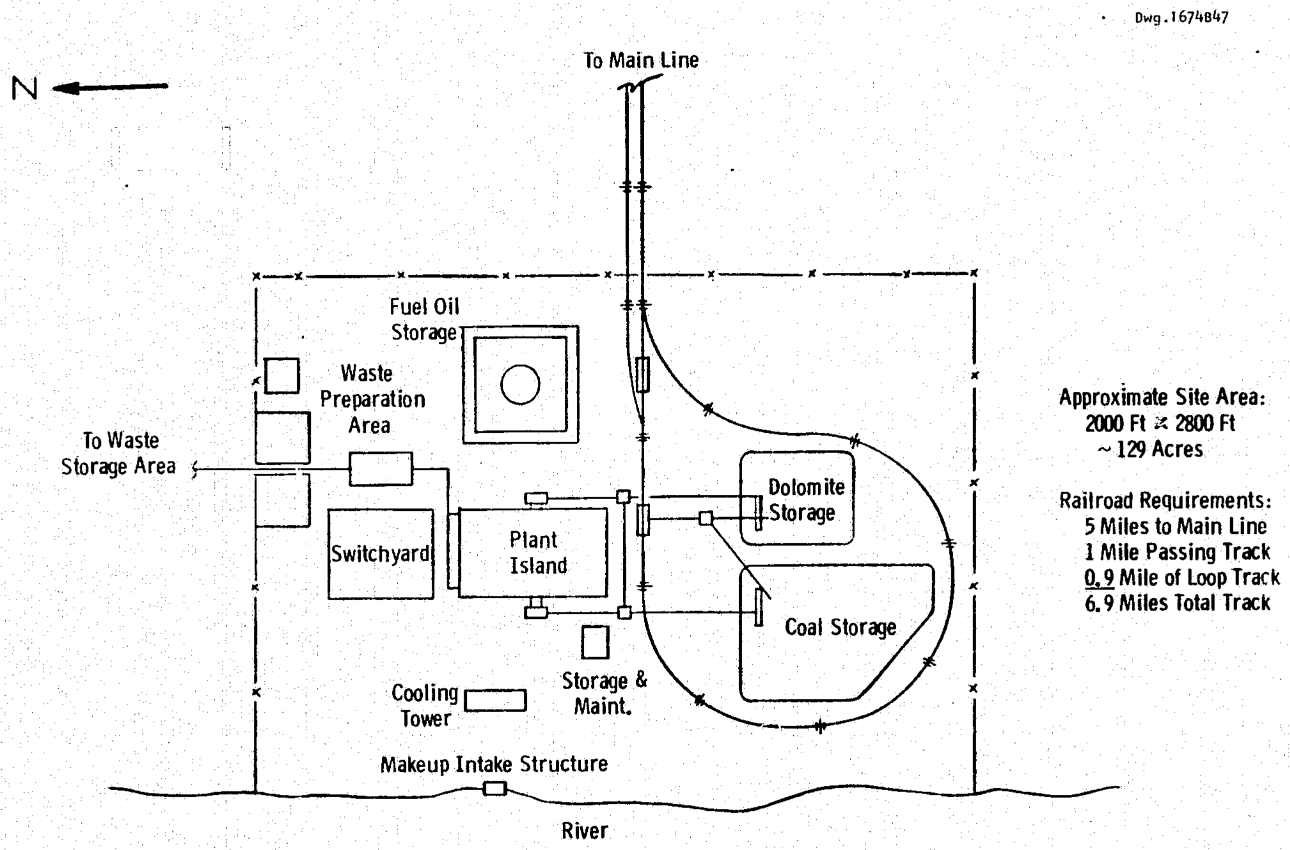


Fig. 6.23—Gas-steam combined cycle plant Base Case A

Scale:
0 100 300 500

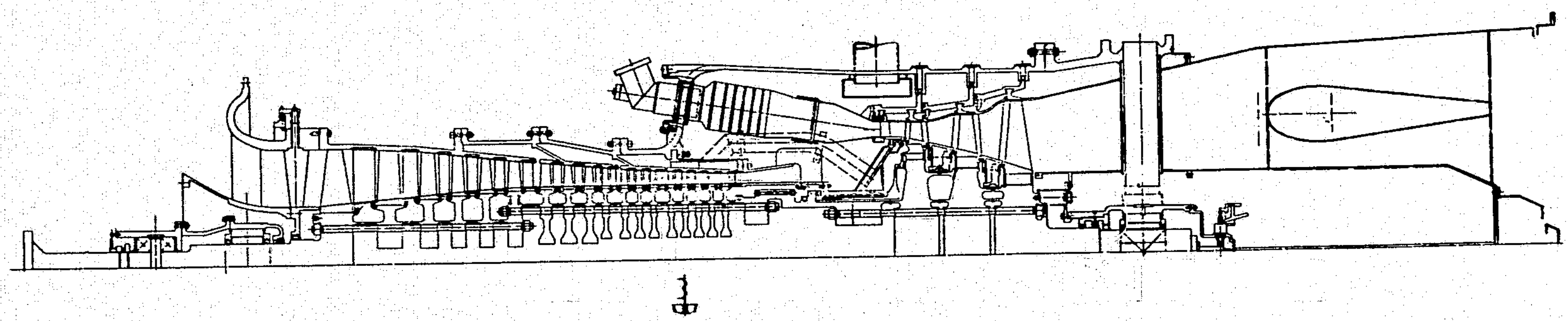


Fig. 6.24—Cross section of gas turbine design concept (Base Case A, Point 1)

The integrated low-Btu gasification plant included in the Base Case A arrangement is patterned after the Westinghouse Advanced Fluidized Bed Gasification process being developed under contract to ERDA. The gasification plant consists of two major elements: the coal and dolomite preparation subsystem and the gasification subsystem. The coal and dolomite preparation equipment is sized so that one subsystem has the capacity to service two gasification subsystems. Each gasification system in turn has the capacity to serve one gas turbine. Coal and dolomite crushing, drying, and silo storing are performed within the coal and dolomite preparation system.

The gasification process, shown schematically in Figure 6.25, operates with two distinct fluidized bed stages—a devolatilization/desulfurization and a gasification/combustion stage. Dry coal is fed to the first stage, where it is devolatilized and converted to char by hot fuel gas from the second stage, the gasifier combustor. In the devolatilizer/desulfurizer, the fuel gas is enriched by the volatile products of the coal and is also desulfurized by dolomite added to the bed. Dolomite is continuously withdrawn and delivered to the spent sorbent oxidizer, where waste heat is recovered. Char from the devolatilizer/desulfurizer is fed continuously to the gasifier/combustor, together with air and steam which react with carbon to produce the hot fuel gas. A second function of the gasifier/combustor is to remove the ash. This is accomplished by regulating the temperature in the combustion zone so that ash particles partially melt and agglomerate to form larger particles which drop out of the fluidized bed. Fuel gas is passed through a particulate separator system and delivered at 1144°K (1600°F) to the gas turbine fuel gas manifold.

Both Base Cases A and B utilize a modular design heat recovery steam generator similar in design to that shown in Figure 6.26. Tube modules, shippable as fully assembled packages, are positioned in each of the parallel gas paths. As the heat recovery steam generators are able to operate for modest periods in a dry and vented mode, gas turbine bypass

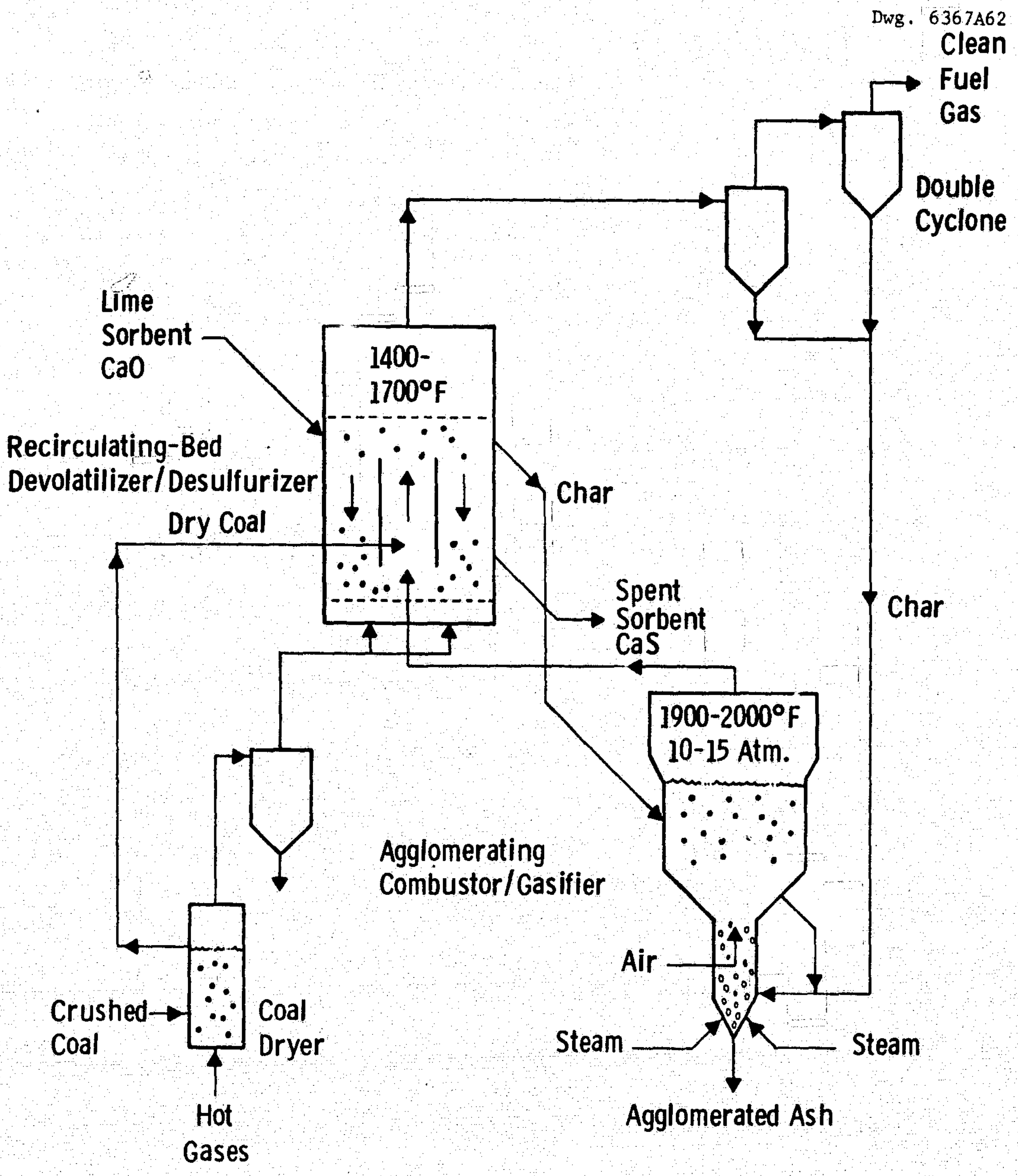
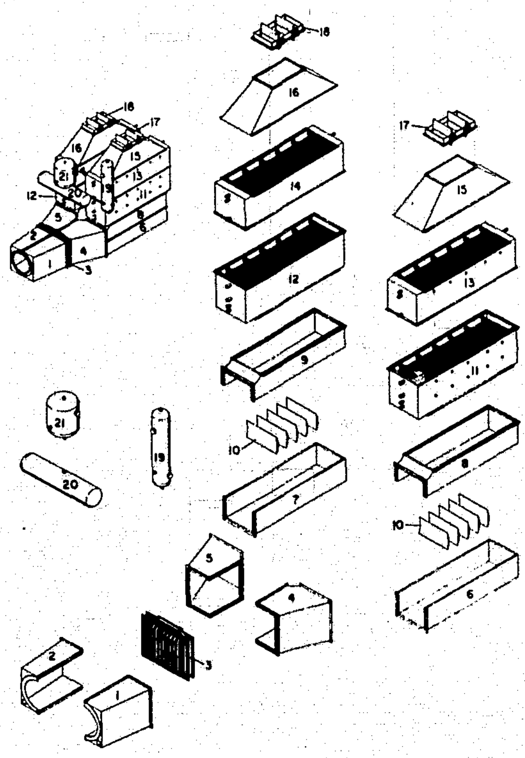
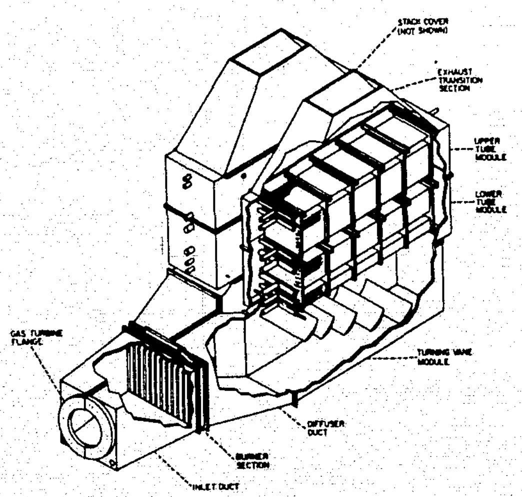


Fig. 6.25—Westinghouse multi-stage fluidized-bed process for the total gasification of coal with desulfurization for an electric power plant



Modularized Construction



Heat Recovery Steam Generator

Fig. 6.26—Sectional view of PACE 260 heat recovery steam generator showing heat recovery steam generator modularized construction

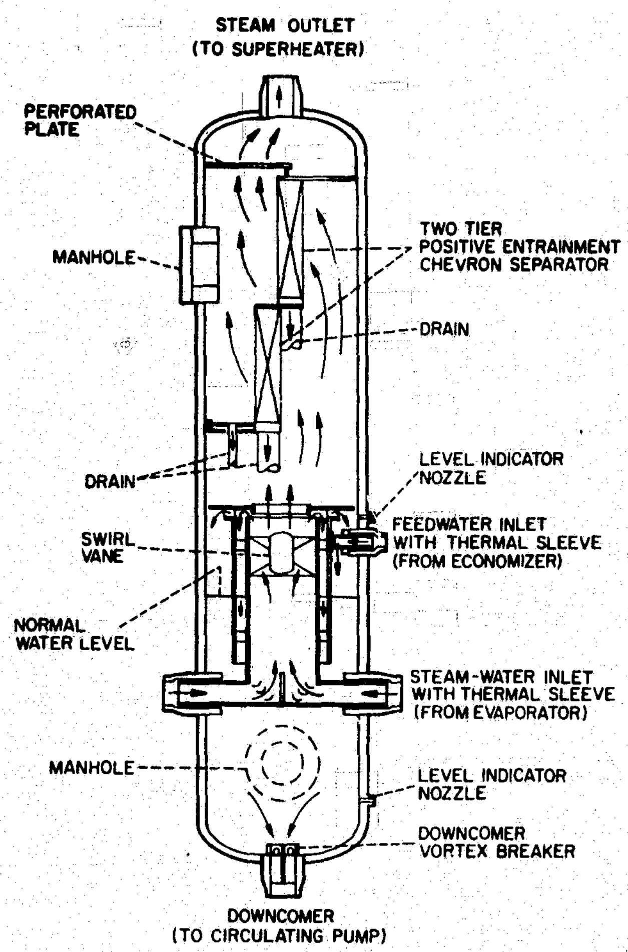


Fig. 6.27 — Vertical steam drum and moisture separator

stacks are not required. The vertical steam drum is shown in Figure 6.27. It utilizes two stages of steam-water separation, a primary centrifugal stage, and a secondary chevron stage. Feedwater heating is accomplished by means of a deaerating feedwater heating system.

The steam turbine is made up of currently available basic components with special modifications to accommodate steam induction. The steam turbine generator is of hydrogen-cooled design featuring a brushless excitation system. The steam turbine condenser is located beneath the LP element and is typical of modern steam station design practice.

The Base Case B power plant island is illustrated by Figure 6.28, and the overall site arrangement is given in Figure 6.29. The design consists of two nominal 130 MW gas turbines of the same design as those considered for Base Case A. The gas turbine exhaust heat is recovered by means of unfired heat recovery steam generators which provide steam for a nominal 8.618 MPa/783°K (1250 psig/950°F) nonreheat steam turbine generator. The gas turbines are fueled by distillate derived from coal.

6.5.2 Approximate Sizes and Weight of Major Components

There are four major components utilized in the combined-cycle energy conversion systems:

- Gas turbine engine
- Heat recovery steam generator
- Steam turbine generator
- Gasification system.

For each base case, the relative plan view sizes of these components is indicated by the plant island arrangements, Figures 6.22 and 6.28. The concept design gas turbine engine is common to both base cases; a cross-sectional view for this major component has been provided in Figure 6.24. Outline views of the Base Cases A and B heat recovery steam generators are shown without steam drums and the interconnecting piping in Figures 6.30

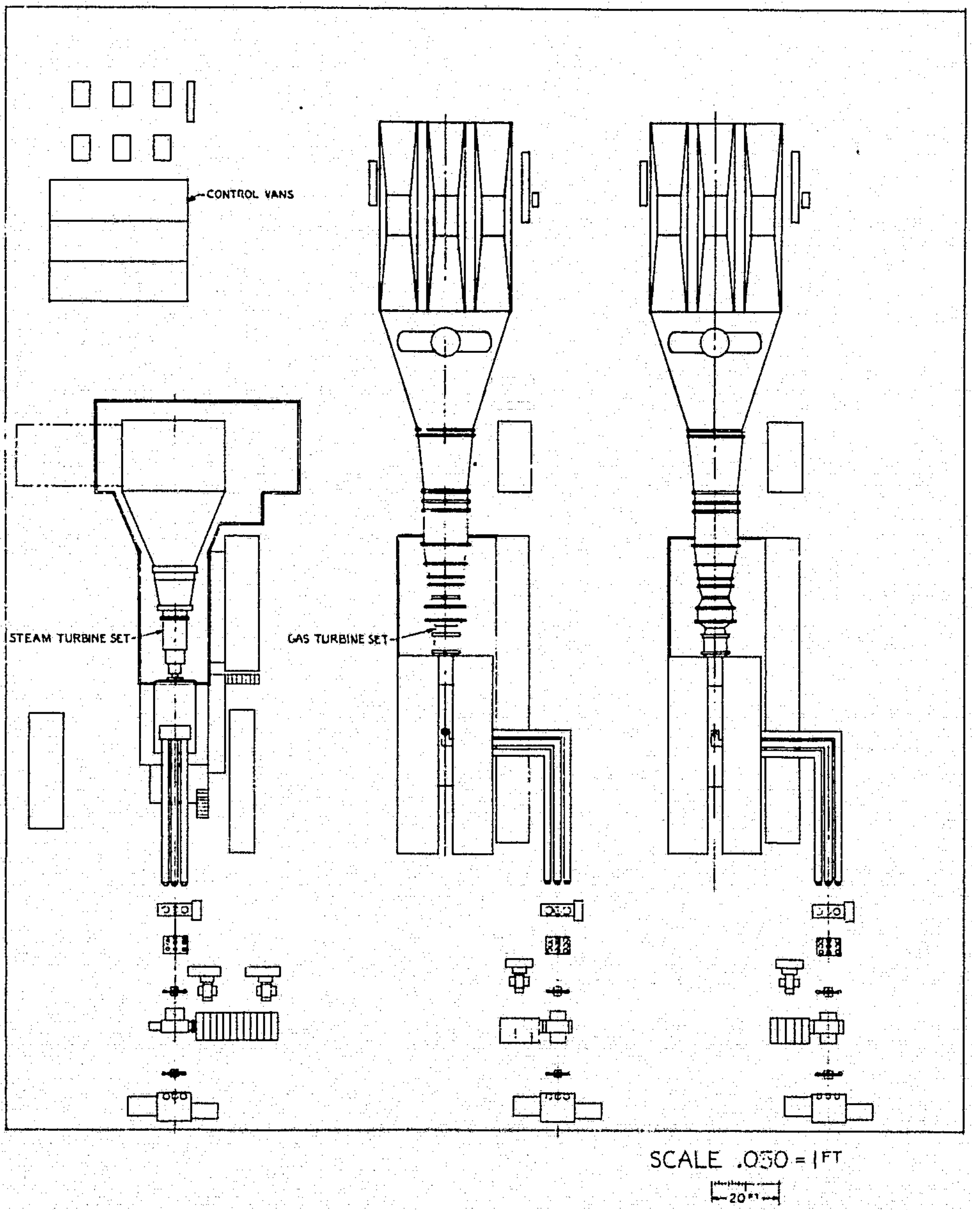
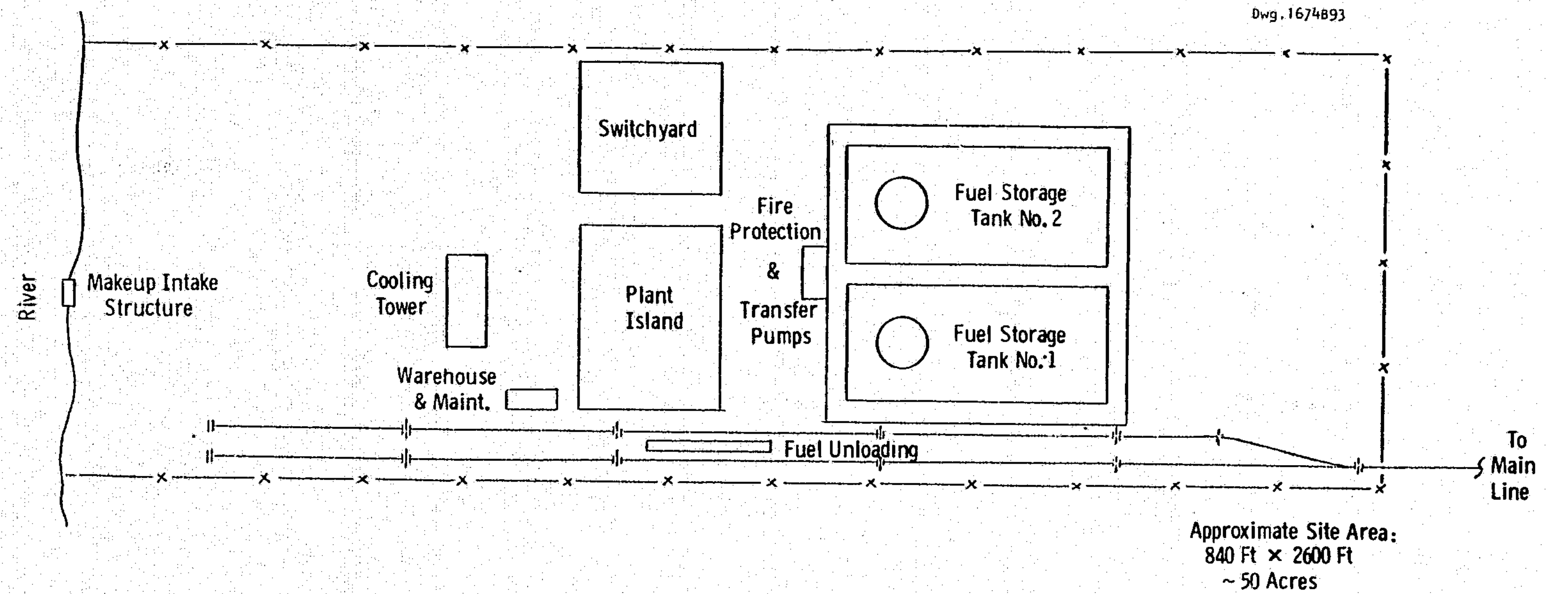


Fig. 6.28—Plant arrangement combined cycle gas-steam turbine - Base Case B



Approximate Site Area:
840 Ft × 2600 Ft
~ 50 Acres

Railroad Requirements:
0.9 Mile Spurs
5.0 Miles to Main Line
5.9 Miles Total Track

Fig. 6.29 — Gas-steam combined cycle Base Case B

N

Scale:
0 50 100 200

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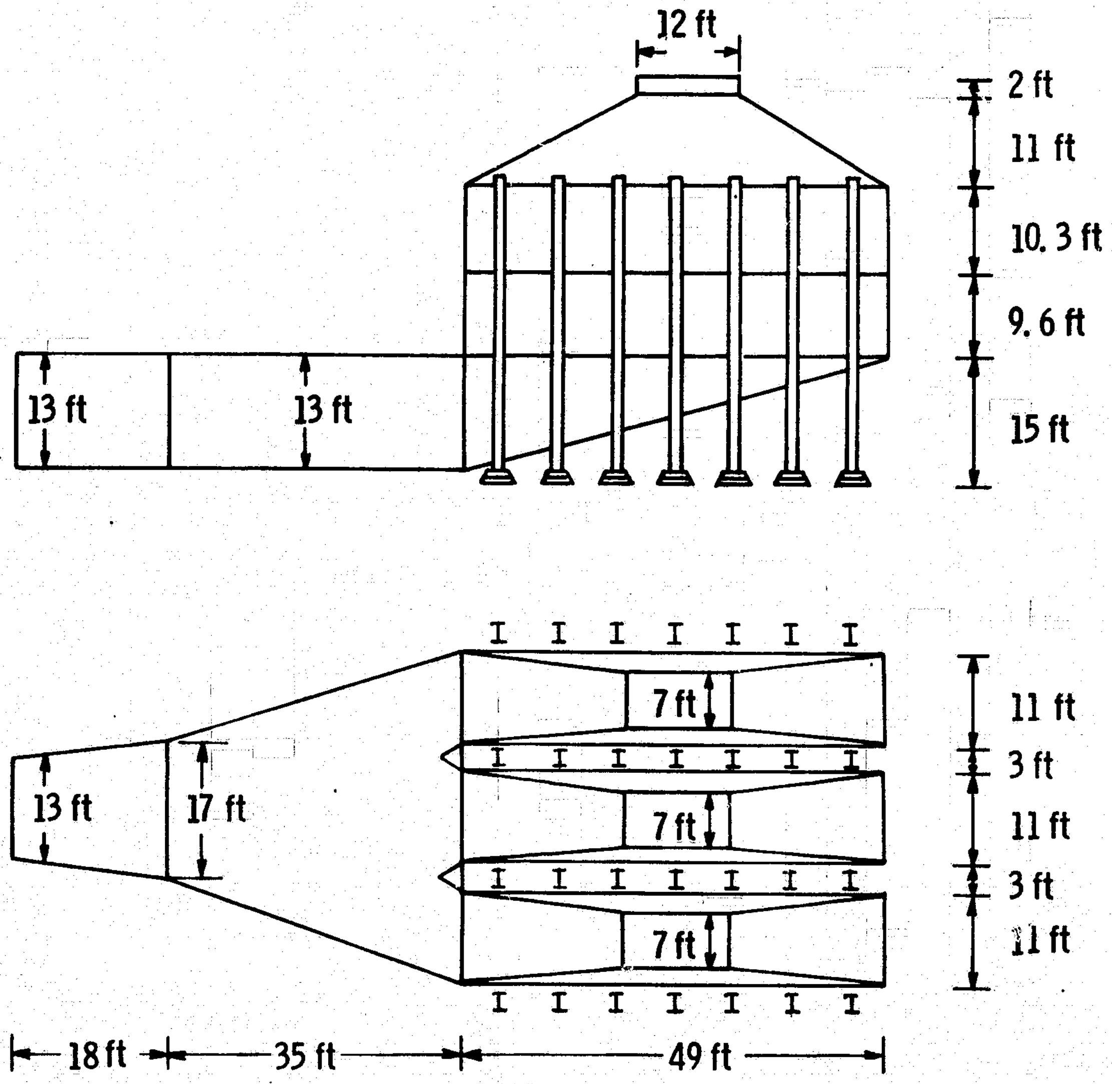

Fig. 6.30—Heat recovery steam generator outline (Base Case B)

and 6.31 illustrates the modular nature of construction utilized for these units. The sizes and masses of the first three major components are listed in Table 6.3.

6.5.3 Price Determination Procedure

For the purpose of establishing power plant cost estimates for parametric analysis, equipment prices were estimated for each of the four major plant components described above. The pricing procedure used for the gas turbine portion of the plant has already been described in Section 5.5.

The pricing of heat recovery steam generators was first approached by developing a number of concept designs. These designs, including the Base Cases A and B models, were formulated by the Westinghouse Heat Transfer Division, using computerized design approaches evolved in the design and development of the PACE combined-cycle modular heat recovery steam generators. The designs were developed sufficiently to determine heat exchange surface requirements, module arrangements and weights, and approximate outline dimensions. Equipment and installation prices were developed for each concept design. The price results were then segregated into price of heat exchanger surface, balance of heat recovery steam generator, and erection price. Heat exchange surface prices were correlated against heat transfer duty, Q/LMTD, and prices for balance of heat recovery steam generator and erection were correlated against steam flow. These price relationships, with suitable modifications for supplementary firing and steam induction, were utilized to determine prices for each parametric point.

The steam turbines were priced from Westinghouse published price lists, using current market level multipliers. The published lists arrive at a price based on the exhaust end size and configuration, power output, generator capacity, steam pressure and temperature, and the scope and extent of features and accessories.

Gasification system description and pricing information are described in Section 4 of this report.

Table 6.3 - Approximate Size and Mass of Base Case Combined-Cycle Major Components

Component	Basic Dimensions, m (ft)			Mass, kg (lb)
Gas Turbine	Length	Diameter		
Turbine section	3.6 (11.7)	4.1 (13.3)		59,000 (130,000)
Compressor section[a]	7.4 (24.2)	3.4 (11.3)		72,500 (160,000)
Heat Recovery Steam Generator	Length	Width	Height	
Base Case A	33.2 (109)	11.9 (39)	16.0 (52.4)	1,200,000 (2,640,000)[b]
Base Case B	31.1 (102)	11.9 (39)	14.6 (47.9)	810,000 (1,782,000)
Steam Turbine-Generator	Length	Diameter		
Overall with generator				
Base Case A	26.2 (86)	5.2 (17)		570,000 (1,250,000)
Base Case B[c]	8.5 (28)	4.0 (13)		109,000 (240,000)

[a] Includes combustion section.

[b] Does not include drums and interconnecting piping.

[c] Does not include generator.

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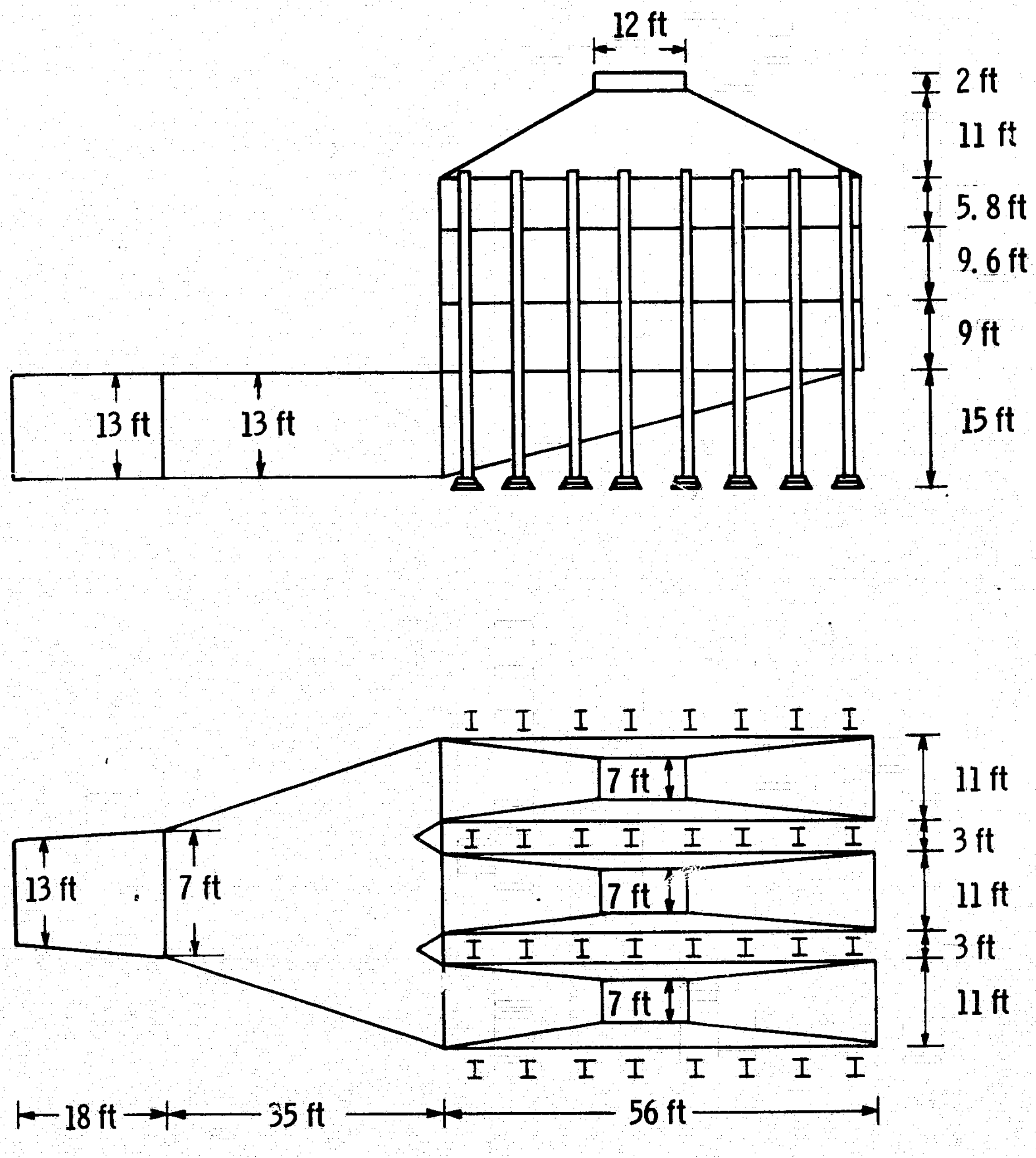

Fig. 6.31 -Heat recovery steam generator outline (Base Case A)

Table 6.4 COMBINED GAS-STEAM TURBINE CYCLE

ACCOUNT NO	AUX POWER,MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	4.77110	12.05576	25.55056	7.70351
7	4.24930	10.73708	824.09284	.00000
8	8.59743	21.72144	2.59304	.00000
14	.00000	.00000	45.36389	.00000
18	5.73360	14.45117	.00000	.00000
20	16.22420	40.99205	5.10167	.00000
TOTALS	39.57563	5.05375	903.99199	7.70351

COMBINED GAS-STEAM TURBINE CYCLE BASE CASE INPUT

NOMINAL POWER, MWE	823.2000	NET POWER, MWE	783.5243
NOM HEAT RATE, BTU/KW-HR	7672.5494	NET HEAT RATE, BTU/KW-HR	8061.0677
ST TURB HEAT RATE CHANGE	.9853		
CONDENSER			
DESIGN PRESSURE, IN HG A	2.0000	NUMBER OF SHELLS	2.0000
NUMBER OF TUBES/SHELL	5072.6807	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	23.0000	OFF DESIGN TEMP, F	77.0000
OFF DESIGN PRES, IN HG A	2.9678	LP TURBINE BLADE LEN, IN	25.0000

1	138.400	2	.000	3	.445	4	.000	5	4.000
6	67.400	7	2.000	8	408100000.000	9	2.000	10	1.000
11	1.000	12	.000	13	1.000	14	4.000	15	1.000
16	1.000	17	129.000	18	3.000	19	5.000	20	2.000
21	.000	22	12700.000	23	.000	24	1250.000	25	.000
26	3510000.000	27	.000	28	10000.000	29	4350000.000	30	.450
31	.650	32	200.000	33	.000	34	.450	35	.450
36	1650000.000	37	350.000	38	1.000	39	1.000	40	644000.000
41	154000.000	42	440000.000	43	10000.000	44	250000.000	45	150000.000
46	1.000	47	.000	48	3.000	49	1.000	50	.000
51	.000	52	5.350						
1	1.000	2	1.000	3	1.000	4	1.000	5	1.000
6	1.000	7	1.000	8	1.000	9	1206800.000	10	.050
11	395500.000	12	.050	13	2541900.000	14	.050	15	1468400.000
16	.140	17	269120C.000	18	.050	19	1221600.000	20	.100
21	571800.000	22	.350	23	2022000.000	24	.080	25	1.000
26	6050000.000	27	.300	28	539900.000	29	.140	30	252600.000
31	.140	32	.000	33	.000	34	.000	35	.000
36	.000	37	.000	38	.000	39	.000	40	.000
41	.000	42	.000	43	.500	44	.000	45	220.000
46	1500.000	47	200.000	48	.000	49	4.000	50	1.000

Steam condenser and power transformer prices have been based upon appropriate published price lists.

The balance of plant pricing has been handled by the architect and engineering firm, Chas. T. Main, Inc., and details of the methods used are described in Section 2 of this report.

6.5.4 Tabulation of Overall Plant Material and Installation Costs

With the exception of heat rejection equipment (steam turbine condensers and cooling towers), the prices of materials and installation were determined, tabulated, and entered into the cost of electricity (COE) calculation computer program. Condenser and cooling tower prices were calculated by means of price correlations preprogrammed into the COE program. Input for both condenser and cooling tower calculations, as well as major equipment cost input for Base Case A, are given in Table 6.4. (Due to an error regarding power for Base Case A the net output and net heat rate shown in Table 6.4 and subsequent tables are incorrect. Corrected values have been used for plotting result curves.) The corresponding output material and installation costs for Base Case A are listed in Table 6.5. This tabulation for each account code item gives the unit measure, amount, material and installation cost per unit, and total material and installation costs.

Similar input and output cost tabulations are given for Base Case B in Tables 6.6 and 6.7.

Material and installation costs for the remaining combined-cycle parametric points have been summarized on Table 6.8. Under the heading "Total Major Component Cost" are included the total direct material costs for the major components (gas turbine auxiliaries, gas turbine generator, steam turbine-generator, and heat recovery steam generator). These and additional cost items for each parametric point are then presented on a \$/kW basis. Included are: total direct major component material costs, balance of plant direct material cost, site-labor, indirect costs, professional services and ownership, contingency and escalation, and interest during construction costs.

Table 6.5 COMBINED GAS-STEAM TURBINE CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 1

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	129.0	1000.00	.00	129000.00	.00
1. 2 CLEARING LAND	ACRE	43.0	.00	600.00	.00	25797.42
1. 3 GRADING LAND	ACRE	129.0	.00	3000.00	.00	387000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.0	120000.00	70000.00	240000.00	140000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	284697.92	284697.92
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 = 1.159				ACCOUNT TOTAL,$	1228697.91	1387495.31
EXCAVATION & PILINGS						
2. 1 COMMON EXCAVATION	YD3	38100.0	.00	3.00	.00	114300.00
2. 2 PILING	FT	101600.0	6.50	8.50	660400.00	863600.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 = .726				ACCOUNT TOTAL,$	660400.00	977900.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	12700.0	70.00	80.00	889000.00	1016000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 = .844				ACCOUNT TOTAL,$	889000.00	1016000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	9.0	.00	.00	1381500.00	688500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	547615.03	734282.55
4. 3 SURFACE CONDENSER	FT2	205702.2	.00	.00	1002961.72	143991.51
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 = 1.994				ACCOUNT TOTAL,$	2932076.75	1566774.05
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	1250.0	650.00	175.00	812500.00	218750.00
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	544000.00	154000.00	544000.00	154000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 5 = .811				ACCOUNT TOTAL,$	1356500.00	372750.00
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	3510000.0	.16	.16	561600.00	561600.00
6. 2 ADMINSTRATION	FT2	.0	16.00	14.00	.00	.00
6. 3 WAREHOUSE & SHOP	FT2	10000.0	12.00	8.00	120000.00	80000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 = .586				ACCOUNT TOTAL,$	681600.00	641600.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	291.1	.00	.00	4205527.25	1877342.64
7. 2 DOLOMITE HAND. SYS	TPH	154.0	.00	.00	1421693.75	688604.93
7. 3 FUEL OIL HAND. SYS	GAL	4350000.0	.00	.00	441488.69	344024.12
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 = 3.979				ACCOUNT TOTAL,$	6068809.69	2909971.69
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	291.1	.00	.00	50770876.00	28558617.75
PERCENT TOTAL DIRECT COST IN ACCOUNT 8 =35.157				ACCOUNT TOTAL,$	50770876.00	28558617.75

Table 6.5 Continued

COMBINED GAS-STEAM TURBINE CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 1

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
FIRING SYSTEM						
9. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 9 = .000 ACCOUNT TOTAL,$					.00	.00
VAPOR GENERATOR (FIRED)						
10. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 = .000 ACCOUNT TOTAL,$					.00	.00
ENERGY CONVERTER						
11. 1 GAS TURB COMP SECT	EA	4.0	1206800.00	60340.00	4827200.00	241360.00
11. 2 GAS TURB COMB SECT	EA	4.0	396500.00	19825.00	1586000.00	79300.00
11. 3 GAS TURB TURB SECT	EA	4.0	2541900.00	127095.00	10167600.00	508380.00
11. 4 GAS TURB ENG AUX	EA	4.0	1468400.00	205576.00	5873600.00	822304.00
11. 5 GAS TURB GENERATOR	EA	4.0	2691200.00	242208.00	10764800.00	968231.99
11. 6 G T MUFFLER & COOLERS	EA	4.0	1221600.00	122160.00	4886400.00	488640.00
11. 7 GAS TURB ENG MISC	EA	4.0	671800.00	235130.00	2687200.00	940520.00
11. 8 STEAM TURBINE-GENER	EA	1.0	10074526.37	836578.39	10074526.37	836578.39
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =24.708 ACCOUNT TOTAL,$					50867326.00	4885914.31
COUPLING HEAT EXCHANGER						
12. 1 HEAT REC STEAM GEN	EA	4.0	6050000.00	1815000.00	24200000.00	7260000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 =13.342 ACCOUNT TOTAL,$					24200000.00	7260000.00
HEAT RECOVERY HEAT EXCH.						
13. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = .000 ACCOUNT TOTAL,$					.00	.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	602.1	2000.00	560.00	1204205.09	337177.43
14. 2 CONDENSATE POLISHING	KWE	.0	1.25	.30	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .683 ACCOUNT TOTAL,$					1204205.09	337177.43
POWER CONDITIONING						
15. 1 STD TRANSFORMER	KVA	1006133.3	.00	.00	3860721.22	77214.42
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.745 ACCOUNT TOTAL,$					3860721.22	77214.42
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	265954.7	.55	.04	146275.07	10638.19
16. 2 OTHER PUMPS	KWE	355431.2	.90	.12	321579.46	43851.74
16. 3 MISC SERVICE SYS	KWE	527845.1	1.17	.73	617578.73	385326.96
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = .676 ACCOUNT TOTAL,$					1085433.25	439816.83
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	800.0	3000.00	1800.00	2400000.00	1440000.00
17. 2 HOT GAS PIPING	FT	220.0	1500.00	200.00	330000.00	44000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 1.868 ACCOUNT TOTAL,$					2730000.00	1484000.00

Table 6.5 COMBINED GAS-STEAM TURBINE CYCLE ACCOUNT LISTING
Continued PARAMETRIC POINT NO. 1

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTORS,ETC		365431.2	1.40	.17	511603.63	62123.30
18. 2 SWITCHGEAR & MCC PAN	KWE	365431.2	1.95	.45	2872190.84	164444.04
18. 3 CONDUIT,CABLES,TRAYS	FT	1650000.0	1.32	1.36	2177999.97	2243999.97
18. 4 ISOLATED PHASE BUS	FT	360.0	510.00	450.00	183600.00	162000.00
18. 5 LIGHTING & COMMUN	KWE	812059.4	.35	.43	284224.27	349189.82
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 3.994				ACCOUNT TOTAL,$	6029618.75	2981757.12
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	440000.00	10000.00	1450400.00	10000.00
19. 2 OTHER CONTROLS	EACH	1.0	250000.00	150000.00	250000.00	150000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = .824				ACCOUNT TOTAL,$	1700400.00	160000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	27.9	1763254.89	440813.72	1763254.89	440813.72
20. 3 WET SLURRY	TPH	154.0	3909804.47	977451.12	3909804.47	977451.12
20. 4 ONSITE DISPOSAL	ACRE	489.5	5798.15	8773.93	2838080.91	4294664.25
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 6.304				ACCOUNT TOTAL,$	8511140.12	5712929.06
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	5765474.81	3747553.53	.00	.00
21. 2 SCRUBBER	KWE	.0	29.81	11.38	.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,$					164276800.00	60769916.00

Table 6.6 COMBINED GAS-STEAM TURBINE CYCLE

ACCOUNT NO	AUX POWER, MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	2.66342	49.11691	14.90890	4.26646
14	.00000	.00000	1.61775	.00000
18	2.75920	50.88318	.00000	.00000
TOTALS	5.42262	1.40729	15.52666	4.26646

COMBINED GAS-STEAM TURBINE CYCLE BASE CASE INPUT

NOMINAL POWER, MWE	390.3000	NET POWER, MWE	395.3774
NOM HEAT RATE, BTU/KW-HR	7336.0919	NET HEAT RATE, BTU/KW-HR	7439.3174
ST TURB HEAT RATE CHANGE	.9854		
CONDENSER			
DESIGN PRESSURE, IN HG A	2.0000	NUMBER OF SHELLS	1.0000
NUMBER OF TUBES/SHELL	5675.5355	TUBE LENGTH, FT	77.4467
U, BTU/HR-FT2-F	591.4577	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	51.4030	APPROACH, F	21.6744
RANGE, F	23.0000	OFF DESIGN TEMP, F	77.0000
OFF DESIGN PRES, IN HG A	2.8718	LP TURBINE BLADE LEN, IN	25.0000

1	120.300	2	.000	3	.465	4	.000	5	3.000
6	57.100	7	2.000	8	456600000.000	9	1.000	10	1.000
11	1.000	12	.000	13	1.000	14	1.000	15	.000
16	1.000	17	50.000	18	3.000	19	5.000	20	.000
21	1.000	22	6600.000	23	.000	24	700.000	25	.000
26	2210000.000	27	2500.000	28	5000.000	29	7250000.000	30	.500
31	.800	32	300.000	33	.000	34	.500	35	.500
36	670000.000	37	300.000	38	1.000	39	1.000	40	322000.000
41	77000.000	42	.000	43	.000	44	60000.000	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	1.000	3	1.000	4	1.000	5	1.000
6	1.000	7	1.000	8	1.000	9	1206800.000	10	.050
11	341500.000	12	.050	13	2475400.000	14	.050	15	1388500.000
16	.140	17	2528700.000	18	.090	19	1148200.000	20	.100
21	333500.000	22	.350	23	2550000.000	24	.080	25	1.000
26	4570000.000	27	.300	28	500400.000	29	.140	30	246200.000
31	.140	32	.000	33	.000	34	.000	35	.000
36	.000	37	.000	38	.000	39	.000	40	.000
41	.000	42	.000	43	.000	44	.000	45	.000
46	.000	47	.000	48	.000	49	2.000	50	1.000

Table 6.7 COMBINED GAS-STEAM TURBINE CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 2

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	50.0	1000.00	.00	50000.00	.00
1. 2 CLEARING LAND	ACRE	16.7	.00	600.00	.00	9995.00
1. 3 GRADING LAND	ACRE	50.0	.00	3000.00	.00	150000.00
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	118248.90	118248.90
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 = 3.051 ACCOUNT TOTAL,$					868248.89	903247.93
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	17800.0	.00	3.00	.00	53400.00
2. 2 PILING	FT	52800.0	6.50	8.50	343200.00	448800.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 = 1.462 ACCOUNT TOTAL,$					343200.00	508200.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	6600.0	70.00	80.00	462000.00	528000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 = 1.700 ACCOUNT TOTAL,$					462000.00	528000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	5.0	.00	.00	757500.00	382500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	306347.74	410773.60
4. 3 SURFACE CONDENSER	FT2	115074.3	.00	.00	543937.39	80551.98
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 = 4.279 ACCOUNT TOTAL,$					1617785.12	873825.57
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	700.0	650.00	175.00	455000.00	122500.00
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 = 1.677 ACCOUNT TOTAL,$					777000.00	199500.00
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	2210000.0	.16	.16	353600.00	353600.00
6. 2 ADMINSTRATION	FT2	2500.0	16.00	14.00	40000.00	35000.00
6. 3 WAREHOUSE & SHOP	FT2	5000.0	12.00	8.00	60000.00	40000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 = 1.515 ACCOUNT TOTAL,$					453600.00	428600.00
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	7250000.0	.00	.00	668096.07	517891.43
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 = 2.037 ACCOUNT TOTAL,$					668096.07	517891.43
FUEL PROCESSING						
8. 1 COAL DRYER & CRUSHER	TPH	.0	.00	.00	.00	.00
8. 2 CARBONIZERS	TPH	.0	.00	.00	.00	.00
8. 3 GASIFIERS	TPH	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 8 = .000 ACCOUNT TOTAL,$					.00	.00

Table 6.7 Continued

COMBINED GAS-STEAM TURBINE CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 2

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		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 = .000 ACCOUNT TOTAL,$					.00	.00
ENERGY CONVERTER						
11. 1 GAS TURB COMP SECT	EA	2.0	1206800.00	60340.00	2413600.00	120680.00
11. 2 GAS TURB COMP SECT	EA	2.0	341500.00	17075.00	683000.00	34150.00
11. 3 GAS TURB TURB SECT	EA	2.0	2475400.00	123770.00	4950800.00	247540.00
11. 4 GAS TURB ENG AUX	EA	2.0	1388500.00	194390.00	2777000.00	388780.00
11. 5 GAS TURB GENERATOR	EA	2.0	2528700.00	227583.00	5057400.00	455165.00
11. 6 G T MUFFLER & COOLERS	EA	2.0	1148200.00	114820.00	2296400.00	229640.00
11. 7 GAS TURB ENG MISC	EA	2.0	333500.00	116725.00	667000.00	233450.00
11. 8 STEAM TURBINE-GENER	EA	1.0	6352631.62	636658.57	6352631.62	636658.57
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =47.307 ACCOUNT TOTAL,$					25197831.50	2346364.53
COUPLING HEAT EXCHANGER						
12. 1 HEAT REC STEAM GEN	EA	2.0	4570000.00	1371000.00	9140000.00	2742000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 =20.408 ACCOUNT TOTAL,$					9140000.00	2742000.00
HEAT RECOVERY HEAT EXCH.						
13. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = .000 ACCOUNT TOTAL,$					.00	.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	21.5	2500.00	700.00	53680.00	15030.40
14. 2 CONDENSATE POLISHING	KWE	.0	1.25	.30	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .118 ACCOUNT TOTAL,$					53680.00	15030.40
POWER CONDITIONING						
15. 1 STD TRANSFORMER	KVA	477544.9	.00	.00	2163929.72	43278.59
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 3.791 ACCOUNT TOTAL,$					2163929.72	43278.59
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP DR.	KWE	155234.9	.55	.04	85379.21	6209.40
16. 2 OTHER PUMPS	KWE	226027.6	.88	.12	198904.29	27123.31
16. 3 MISC SERVICE SYS	KWE	361644.2	1.17	.73	423123.56	264000.23
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 1.725 ACCOUNT TOTAL,$					707407.14	297332.93
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	300.0	3000.00	1800.00	900000.00	540000.00
17. 2 HOT GAS PIPING	FT	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 2.473 ACCOUNT TOTAL,$					900000.00	540000.00

Table 6.7
Continued

COMBINED GAS-STEAM TURBINE CYCLE ACCOUNT LISTING
PARAMETRIC POINT NO. 2

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		226027.6	1.40	.17	316438.64	38424.69
18. 2 SWITCHGEAR & MCC PAN	KWE	226027.6	1.95	.45	1441553.81	101712.42
18. 3 CONDUIT,CABLES,TRAYS	FT	670000.0	1.32	1.36	884399.99	911199.99
18. 4 ISOLATED PHASE BUS	FT	300.0	510.00	450.00	153000.00	135000.00
18. 5 LIGHTING & COMMUN	KWE	452055.2	.35	.43	158219.32	194383.73
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 7.444 ACCOUNT TOTAL,$					2953611.72	1380720.81
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	.00	.00	492400.00	.00
19. 2 OTHER CONTROLS	EACH	1.0	60000.00	36000.00	60000.00	36000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = 1.011 ACCOUNT TOTAL,$					552400.00	36000.00
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	34.16	15.56	.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,$					45858789.00	11354591.87

Table 6.8 COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT	1	2	3	4	5	6	7	8
	TOTAL CAPITAL COST ,M$	383.07	89.84	92.44	195.30	206.81	Not Calculated	198.10	190.38
P	GAS TURBINE COMPRESSOR SECT,M$	4.827	2.414	2.414	4.827	4.827		4.827	4.827
L	GAS TURBINE COMB BASKETS ,M$	1.538	.683	.683	1.366	1.366		1.366	1.366
A	GAS TURBINE TURBINE SECTION,M$	10.188	4.951	4.951	9.902	9.902		9.902	9.902
N	MISC GAS TURBINE AUXILIARY ,M$	13.447	5.740	5.740	11.481	11.481		11.481	11.481
T	GAS TURBINE GENERATOR ,M$	10.765	5.057	5.057	10.115	10.115		10.115	10.115
	STEAM TURBINE GENERATOR ,M$	10.075	6.353	7.115	12.212	12.222		10.084	10.045
	HEAT RECOVERY STEAM GEN ,M$	24.200	9.140	9.670	25.260	27.540		25.480	22.060
R	TOT MAJOR COMPONENT COST ,M$	75.037	34.338	35.630	75.162	77.452		73.255	69.795
E	TOT MAJOR COMPONENT COST,$/KWE	95.807	89.102	91.334	94.711	97.350		93.694	90.468
S	BALANCE OF PLANT COST ,$/KWE	114.622	32.490	32.332	26.295	28.763		29.117	29.552
U	SITE LABOR ,$/KWE	77.560	29.490	29.859	27.283	29.681		29.127	28.166
L	TOTAL DIRECT COST ,$/KWE	287.989	151.082	153.525	148.289	155.795		151.938	148.186
T	INDIRECT COSTS ,$/KWE	38.555	15.040	15.228	13.914	15.130		14.855	14.365
	PROF & OWNER COSTS ,$/KWE	23.038	12.087	12.282	11.853	12.464		12.155	11.855
B	CONTINGENCY COST ,$/KWE	20.159	9.065	9.221	10.356	10.883		10.595	10.320
R	ESCALATION COST ,$/KWE	53.523	22.077	22.430	29.480	31.070		30.212	28.370
E	INT DURING CONSTRUCTION ,$/KWE	66.293	23.775	24.214	32.815	34.587		33.618	32.671
A	TOTAL CAPITALIZATION ,$/KWE	496.553	233.125	235.951	246.717	259.936		253.372	245.766
K	COST OF ELEC-CAPITAL ,MILLS/KWE	15.697	7.370	7.491	7.799	8.217		8.010	7.801
D	COST OF ELEC-FUEL ,MILLS/KWE	6.852	19.342	19.108	18.792	18.733		19.073	19.325
O	COST OF ELEC-OP&MAIN,MILLS/KWE	1.702	.591	.591	.589	.588		.588	.589
W	TOTAL COST OF ELEC ,MILLS/KWE	24.251	27.303	27.190	27.180	27.539		27.670	27.715
N	COE 0.5 CAP. FACTOR ,MILLS/KWE	29.071	29.625	29.548	29.631	30.115		30.184	30.167
	COE 0.8 CAP. FACTOR ,MILLS/KWE	21.233	25.846	25.711	25.643	25.923		26.094	26.178
	COE 1.2XCAP. COST ,MILLS/KWE	27.390	28.777	28.688	28.740	29.181		29.272	29.275
	COE 1.2XFUEL COST ,MILLS/KWE	25.621	31.171	31.011	30.939	31.295		31.485	31.580
	COE (CONTINGENCY=0) ,MILLS/KWE	23.397	26.946	26.827	26.742	27.078		27.222	27.279
	COE (ESCALATION=0) ,MILLS/KWE	22.122	26.537	26.410	26.125	26.427		26.591	26.666

	PARAMETRIC POINT	9	10	11	12	13	14	15	16
	TOTAL CAPITAL COST ,M$	191.92	192.80	191.01	196.27	183.59	188.33	193.60	216.13
P	GAS TURBINE COMPRESSOR SECT,M$	4.827	4.827	4.827	4.827	4.827	4.827	4.827	4.827
L	GAS TURBINE COMB BASKETS ,M$	1.366	1.366	1.366	1.366	1.366	1.366	1.366	1.366
A	GAS TURBINE TURBINE SECTION,M$	9.924	9.980	9.902	9.902	9.902	9.902	9.902	9.902
N	MISC GAS TURBINE AUXILIARY ,M$	11.540	11.424	11.481	11.481	11.481	11.481	11.481	11.481
T	GAS TURBINE GENERATOR ,M$	10.170	10.062	10.115	10.115	10.115	10.115	10.115	10.115
	STEAM TURBINE GENERATOR ,M$	9.781	9.925	9.855	9.870	9.163	10.030	9.023	11.938
	HEAT RECOVERY STEAM GEN ,M$	22.740	23.320	22.520	24.720	21.104	23.120	23.120	31.640
R	TOT MAJOR COMPONENT COST ,M$	70.348	70.803	70.066	72.281	67.957	70.840	69.834	81.268
E	TOT MAJOR COMPONENT COST,$/KWE	90.527	91.445	90.863	92.781	90.674	90.354	96.207	101.843
S	BALANCE OF PLANT COST ,$/KWE	29.437	29.468	29.546	29.383	29.055	27.075	36.555	29.054
U	SITE LABOR ,$/KWE	28.254	28.535	28.326	28.951	27.741	26.936	28.716	31.258
L	TOTAL DIRECT COST ,$/KWE	148.219	149.449	148.734	151.115	147.470	144.366	161.478	162.155
T	INDIRECT COSTS ,$/KWE	14.410	14.553	14.445	14.765	14.148	13.739	14.645	15.941
	PROF & OWNER COSTS ,$/KWE	11.857	11.956	11.899	12.089	11.798	11.549	12.918	12.972
B	CONTINGENCY COST ,$/KWE	10.330	10.412	10.353	10.534	10.239	10.065	11.184	11.331
R	ESCALATION COST ,$/KWE	29.424	29.652	29.480	30.026	29.030	28.635	31.499	32.387
E	INT DURING CONSTRUCTION ,$/KWE	32.737	32.987	32.794	33.403	32.270	31.861	34.995	35.055
A	TOTAL CAPITALIZATION ,$/KWE	246.976	249.008	247.711	251.936	244.955	240.213	266.719	270.842
K	COST OF ELEC-CAPITAL,MILLS/KWE	7.807	7.872	7.831	7.964	7.744	7.594	8.432	8.562
D	COST OF ELEC-FUEL ,MILLS/KWE	19.188	19.259	19.337	19.139	19.891	19.018	20.543	18.682
O	COST OF ELEC-OP&MAIN,MILLS/KWE	.588	.589	.589	.588	.579	.552	.552	.588
W	TOTAL COST OF ELEC ,MILLS/KWE	27.583	27.719	27.757	27.691	28.214	27.164	29.526	27.832
N	COE 0.5 CAP. FACTOR ,MILLS/KWE	30.037	30.192	30.217	30.192	30.648	29.553	32.167	30.512
	COE 0.8 CAP. FACTOR ,MILLS/KWE	26.045	26.169	26.214	26.123	26.687	25.665	27.871	26.152
	COE 1.2XCAP. COST ,MILLS/KWE	29.145	29.234	29.323	29.284	29.762	28.682	31.213	29.544
	COE 1.2XFUEL COST ,MILLS/KWE	31.421	31.571	31.624	31.519	32.192	30.967	33.635	31.568
	COE (CONTINGENCY=0) ,MILLS/KWE	27.147	27.279	27.319	27.246	27.782	26.738	29.055	27.353
	COE (ESCALATION=0) ,MILLS/KWE	26.532	26.660	26.704	26.618	27.177	26.140	28.402	26.674

Table 6.8
Continued

COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT		17	18	19	20	21	22	23	24
	TOTAL CAPITAL COST	,M$	212.42	205.48	273.25	92.25	38.34	89.95	89.77	89.24
P	GAS TURBINE COMPRESSOR SECT	,M$	3.620	2.414	2.414	2.414	2.414	2.414	2.414	2.414
L	GAS TURBINE COMB BASKETS	,M$	1.024	.683	.683	.683	.683	.683	.683	.683
A	GAS TURBINE TURBINE SECTION	,M$	7.426	4.951	4.951	4.951	4.951	4.962	4.940	4.951
N	MISC GAS TURBINE AUXILIARY	,M$	8.611	5.740	5.740	5.740	5.740	5.770	5.712	5.740
T	GAS TURBINE GENERATOR	,M$	7.586	5.057	5.057	5.057	5.057	5.085	5.031	5.057
	STEAM TURBINE GENERATOR	,M$	13.036	15.933	24.852	6.457	6.285	6.315	6.390	[illegible].325
	HEAT RECOVERY STEAM GEN	,M$	28.998	26.610	34.998	10.200	8.730	9.140	9.150	[illegible].880
R	TOT MAJOR COMPONENT COST	,M$	70.352	62.388	78.636	35.502	33.861	34.369	34.319	34.050
E	TOT MAJOR COMPONENT COST	,$/KWE	93.362	79.702	74.773	91.603	89.183	88.950	89.241	88.493
S	BALANCE OF PLANT COST	,$/KWE	34.339	32.691	34.519	32.379	32.563	32.454	32.518	32.518
U	SITE LABOR	,$/KWE	33.752	31.248	31.765	30.202	29.239	29.442	29.535	29.315
L	TOTAL DIRECT COST	,$/KWE	161.514	143.641	141.158	154.184	149.985	150.847	151.[illegible]	150.326
T	INDIRECT COSTS	,$/KWE	17.214	15.936	16.200	15.403	14.912	15.016	15.063	14.951
	PROF & OWNER COSTS	,$/KWE	12.921	11.491	11.233	12.335	11.399	12.053	12.103	12.026
B	CONTINGENCY COST	,$/KWE	12.030	11.451	11.628	9.256	8.996	9.053	9.076	9.018
R	ESCALATION COST	,$/KWE	39.713	37.189	38.315	22.551	21.300	22.054	22.100	21.959
E	INT DURING CONSTRUCTION	,$/KWE	41.511	42.796	45.187	24.298	23.582	23.750	23.798	23.646
A	TOTAL CAPITALIZATION	,$/KWE	281.932	252.504	254.333	238.036	231.374	232.737	233.434	231.926
K	COST OF ELEC-CAPITAL	,MILLS/KWE	8.912	8.298	8.358	7.525	7.314	7.359	7.379	7.332
D	COST OF ELEC-FUEL	,MILLS/KWE	19.237	20.262	20.300	19.234	19.418	19.296	19.389	19.376
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.636	.609	.615	.590	.591	.591	.591	.591
W	TOTAL COST OF ELEC	,MILLS/KWE	28.784	29.169	28.873	27.349	27.323	27.245	27.359	27.298
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	31.569	31.770	32.492	29.718	29.629	29.564	29.685	29.609
	COE 0.8 CAP. FACTOR	,MILLS/KWE	27.030	27.538	28.231	25.863	25.977	25.791	25.901	25.849
	COE 1.2XCAP. COST	,MILLS/KWE	30.566	30.828	31.545	28.854	28.786	28.717	28.835	28.765
	COE 1.2XFUEL COST	,MILLS/KWE	32.631	33.221	34.053	31.195	31.207	31.104	31.237	31.173
	COE (CONTINGENCY=0)	,MILLS/KWE	28.258	28.648	29.334	26.984	26.969	26.889	27.002	26.943
	COE (ESCALATION=0)	,MILLS/KWE	27.453	27.799	28.427	26.566	25.564	26.493	26.593	26.537

	PARAMETRIC POINT		25	25	27	28	29	30	31	32
	TOTAL CAPITAL COST	,M$	91.44	88.12	87.69	89.27	90.57	122.58	100.67	134.63
P	GAS TURBINE COMPRESSOR SECT	,M$	2.414	2.414	2.414	2.414	2.414	2.414	1.207	1.207
L	GAS TURBINE COMB BASKETS	,M$	.683	.683	.683	.683	.683	.683	.342	.342
A	GAS TURBINE TURBINE SECTION	,M$	4.951	4.951	4.951	4.951	4.951	4.951	2.475	2.475
N	MISC GAS TURBINE AUXILIARY	,M$	5.740	5.740	5.740	5.740	5.740	5.740	2.870	2.870
T	GAS TURBINE GENERATOR	,M$	5.057	5.057	5.057	5.057	5.057	5.057	2.529	2.529
	STEAM TURBINE GENERATOR	,M$	6.390	6.278	6.495	5.421	7.000	9.257	10.330	12.981
	HEAT RECOVERY STEAM GEN	,M$	9.880	8.560	9.030	9.100	8.998	14.454	9.198	12.268
R	TOT MAJOR COMPONENT COST	,M$	35.115	33.683	34.430	33.366	34.844	42.557	28.950	34.671
E	TOT MAJOR COMPONENT COST	,$/KWE	90.932	88.500	83.132	93.104	90.767	92.409	81.851	74.186
S	BALANCE OF PLANT COST	,$/KWE	32.454	32.526	29.812	40.042	32.591	36.040	45.836	50.286
U	SITE LABOR	,$/KWE	30.028	29.158	27.792	29.623	29.659	34.560	40.137	41.834
L	TOTAL DIRECT COST	,$/KWE	153.414	150.194	145.796	162.769	153.017	163.009	167.825	166.306
T	INDIRECT COSTS	,$/KWE	15.314	14.876	14.174	15.108	15.126	17.626	20.470	21.336
	PROF & OWNER COSTS	,$/KWE	12.273	12.016	11.664	13.022	12.241	13.041	13.426	13.305
B	CONTINGENCY COST	,$/KWE	9.237	9.001	8.754	9.709	9.178	10.778	11.655	11.880
R	ESCALATION COST	,$/KWE	22.432	21.885	21.296	23.355	22.331	29.398	33.744	35.502
E	INT DURING CONSTRUCTION	,$/KWE	24.157	23.562	22.936	25.122	24.047	32.317	37.512	39.732
A	TOTAL CAPITALIZATION	,$/KWE	236.798	231.534	224.619	249.084	235.940	266.168	284.631	288.060
K	COST OF ELEC-CAPITAL	,MILLS/KWE	7.495	7.319	7.101	7.874	7.459	8.414	8.998	9.106
D	COST OF ELEC-FUEL	,MILLS/KWE	19.309	19.583	19.100	20.798	19.419	19.971	22.404	23.519
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.531	.588	.552	.552	.592	.599	.621	.631
W	TOTAL COST OF ELEC	,MILLS/KWE	27.385	27.490	26.753	29.223	27.470	28.984	32.023	33.256
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	29.742	29.797	28.935	31.637	29.918	31.620	34.834	36.099
	COE 0.8 CAP. FACTOR	,MILLS/KWE	25.907	26.043	25.347	27.672	25.996	27.332	30.261	31.474
	COE 1.2XCAP. COST	,MILLS/KWE	28.832	28.953	28.173	30.798	28.961	30.667	33.823	35.077
	COE 1.2XFUEL COST	,MILLS/KWE	31.247	31.406	30.573	33.383	31.353	32.978	36.504	37.960
	COE (CONTINGENCY=0)	,MILLS/KWE	27.023	27.135	26.409	28.842	27.108	28.541	31.532	32.748
	COE (ESCALATION=0)	,MILLS/KWE	26.607	26.731	26.015	28.[illegible]15	26.695	27.545	30.818	31.981

Table 6.8 COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT		33	34	35	36	37	38	39	40
	TOTAL CAPITAL COST	,M$	155.73	147.22	144.30	137.26	131.42	167.17	163.13	155.37
P	GAS TURBINE COMPRESSOR SECT	,M$	4.459	4.827	8.338	8.907	4.459	4.827	8.338	8.907
L	GAS TURBINE COMB BASKETS	,M$	1.081	1.222	1.279	1.237	1.147	1.294	1.352	1.358
A	GAS TURBINE TURBINE SECTION	,M$	9.145	8.982	9.524	9.991	9.535	9.450	10.114	10.553
N	MISC GAS TURBINE AUXILIARY	,M$	8.533	8.373	8.927	8.851	8.773	8.829	9.674	9.256
T	GAS TURBINE GENERATOR	,M$	7.646	7.946	8.005	7.928	8.871	9.031	8.773	8.346
	STEAM TURBINE GENERATOR	,M$	3.734	7.539	6.333	5.325	10.314	8.500	7.783	7.220
	HEAT RECOVERY STEAM GEN	,M$	10.300	10.220	14.268	13.016	23.440	18.900	16.720	15.120
R	TOT MAJOR COMPONENT COST	,M$	57.342	55.604	55.733	55.303	55.535	61.931	62.734	60.759
E	TOT MAJOR COMPONENT COST	,$/KWE	99.551	106.262	122.424	130.010	93.808	95.549	106.687	114.477
S	BALANCE OF PLANT COST	,$/KWE	32.334	34.198	36.133	38.360	30.336	31.222	32.375	33.935
U	SITE LABOR	,$/KWE	31.654	33.309	34.069	36.421	29.913	29.644	30.608	31.960
L	TOTAL DIRECT COST	,$/KWE	164.039	172.770	192.627	211.231	154.057	156.414	169.750	180.371
T	INDIRECT COSTS	,$/KWE	15.144	16.478	17.375	18.575	15.256	15.118	15.651	16.299
	PROF & OWNER COSTS	,$/KWE	13.127	13.822	15.410	15.902	12.325	12.513	13.580	14.430
B	CONTINGENCY COST	,$/KWE	11.116	11.583	12.765	13.827	10.641	10.707	11.509	12.108
R	ESCALATION COST	,$/KWE	30.823	31.715	34.398	36.713	30.032	29.961	31.788	33.063
E	INT DURING CONSTRUCTION	,$/KWE	34.076	34.973	37.833	40.267	33.410	33.155	35.143	36.470
A	TOTAL CAPITALIZATION	,$/KWE	268.330	281.340	310.408	337.565	255.781	257.909	277.422	292.743
K	COST OF ELEC-CAPITAL	,MILLS/KWE	8.510	8.894	9.813	10.671	8.086	8.153	8.770	9.254
D	COST OF ELEC-FUEL	,MILLS/KWE	21.339	21.445	22.036	23.005	20.162	20.200	20.599	21.213
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.597	.594	.593	.594	.593	.591	.590	.590
W	TOTAL COST OF ELEC	,MILLS/KWE	30.511	30.934	32.442	34.270	28.841	28.944	29.960	31.058
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	33.178	33.713	35.498	37.582	31.378	31.501	32.702	33.945
	COE 0.8 CAP. FACTOR	,MILLS/KWE	28.349	29.192	30.529	32.194	27.250	27.341	28.241	29.248
	COE 1.2XCAP. COST	,MILLS/KWE	32.215	32.713	34.405	36.404	30.458	30.575	31.714	32.909
	COE 1.2XFUEL COST	,MILLS/KWE	34.731	35.223	36.850	38.871	32.373	32.934	34.079	35.300
	COE (CONTINGENCY=0)	,MILLS/KWE	30.049	30.454	31.916	33.703	28.393	28.496	29.480	30.556
	COE (ESCALATION=0)	,MILLS/KWE	29.417	29.813	31.225	32.975	27.767	27.873	28.830	29.886

	PARAMETRIC POINT		41	42	43	44	45	46	47	48
	TOTAL CAPITAL COST	,M$	200.90	192.42	183.82	175.35	235.57	220.94	207.10	195.69
P	GAS TURBINE COMPRESSOR SECT	,M$	4.459	4.827	8.339	8.907	4.459	4.827	8.333	8.907
L	GAS TURBINE COMB BASKETS	,M$	1.213	1.366	1.424	1.430	1.280	1.439	1.497	1.501
A	GAS TURBINE TURBINE SECTION	,M$	10.343	9.932	10.522	11.093	10.759	11.994	11.100	11.606
N	MISC GAS TURBINE AUXILIARY	,M$	10.687	11.481	10.864	10.491	11.888	12.063	12.044	11.731
T	GAS TURBINE GENERATOR	,M$	9.788	10.115	9.952	9.592	10.354	11.155	11.104	10.874
	STEAM TURBINE GENERATOR	,M$	11.504	9.855	8.978	8.195	13.692	11.315	9.900	8.929
	HEAT RECOVERY STEAM GEN	,M$	24.750	23.200	19.300	17.444	32.940	28.280	23.240	20.270
R	TOT MAJOR COMPONENT COST	,M$	72.758	70.746	69.488	67.153	85.971	81.072	77.223	73.677
E	TOT MAJOR COMPONENT COST	,$/KWE	87.019	91.229	97.464	102.599	83.723	89.634	91.940	94.566
S	BALANCE OF PLANT COST	,$/KWE	28.819	29.265	29.972	31.113	27.593	27.985	28.359	29.099
U	SITE LABOR	,$/KWE	27.641	28.421	28.532	29.329	28.250	27.740	27.349	27.570
L	TOTAL DIRECT COST	,$/KWE	143.479	148.915	155.969	163.041	145.565	145.410	147.648	151.235
T	INDIRECT COSTS	,$/KWE	14.097	14.495	14.551	14.957	14.407	14.148	13.948	14.261
	PROF & OWNER COSTS	,$/KWE	11.473	11.913	12.477	13.043	11.645	11.633	11.812	12.099
B	CONTINGENCY COST	,$/KWE	10.073	10.375	10.777	11.171	10.361	10.288	10.370	10.542
R	ESCALATION COST	,$/KWE	29.921	29.553	30.349	31.162	30.152	29.734	29.691	29.933
E	INT DURING CONSTRUCTION	,$/KWE	32.233	32.879	33.593	34.533	33.715	33.200	33.094	33.304
A	TOTAL CAPITALIZATION	,$/KWE	240.231	248.131	257.922	267.907	245.840	244.412	246.502	251.174
K	COST OF ELEC-CAPITAL	,MILLS/KWE	7.537	7.844	8.150	8.463	7.772	7.725	7.794	7.940
D	COST OF ELEC-FUEL	,MILLS/KWE	19.259	19.221	19.566	20.024	18.628	18.462	18.744	19.156
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.580	.583	.583	.583	.589	.585	.585	.586
W	TOTAL COST OF ELEC	,MILLS/KWE	27.444	27.653	28.304	29.081	26.989	26.775	27.124	27.682
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	29.334	30.119	30.361	31.733	29.431	29.204	29.574	30.175
	COE 0.8 CAP. FACTOR	,MILLS/KWE	25.946	26.108	26.701	27.419	25.457	25.252	25.588	26.118
	COE 1.2XCAP. COST	,MILLS/KWE	28.954	29.222	29.934	30.775	28.543	28.320	28.683	29.270
	COE 1.2XFUEL COST	,MILLS/KWE	31.296	31.498	32.217	33.086	30.714	30.469	30.873	31.513
	COE (CONTINGENCY=0)	,MILLS/KWE	27.017	27.215	27.851	28.613	26.546	26.337	26.684	27.236
	COE (ESCALATION=0)	,MILLS/KWE	26.409	26.598	27.222	27.972	25.906	25.709	26.062	26.612

Table 6.8 Continued

COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS

	PARAMETRIC POINT		49	50	51	52	53	54	55	56
	TOTAL CAPITAL COST	,M$	251.24	241.48	228.81	218.51	75.19	70.75	69.59	66.70
P	GAS TURBINE COMPRESSOR SECT	,M$	4.459	4.827	8.338	8.907	2.230	2.414	4.169	4.453
L	GAS TURBINE COMB BASKETS	,M$	1.345	1.510	1.570	1.572	.540	.611	.639	.643
A	GAS TURBINE TURBINE SECTION	,M$	11.172	12.495	13.448	12.124	4.072	4.491	4.797	4.996
N	MISC GAS TURBINE AUXILIARY	,M$	12.515	13.217	13.274	13.028	4.293	4.435	4.463	4.425
T	GAS TURBINE GENERATOR	,M$	11.550	12.209	12.261	12.032	3.824	3.973	4.003	3.963
	STEAM TURBINE GENERATOR	,M$	14.957	12.915	11.609	10.274	5.324	4.260	3.657	3.097
	HEAT RECOVERY STEAM GEN	,M$	34.560	30.640	24.240	23.620	8.430	7.320	6.640	6.180
R	TOT MAJOR COMPONENT COST	,M$	30.539	87.813	84.741	81.557	23.712	27.503	28.368	27.757
E	TOT MAJOR COMPONENT COST	,$/KWE	84.767	85.412	87.679	90.070	98.600	104.443	120.851	134.417
S	BALANCE OF PLANT COST	,$/KWE	25.600	25.810	27.343	27.591	36.723	38.079	39.823	42.750
U	SITE LABOR	,$/KWE	26.905	26.463	25.736	26.413	33.687	34.396	36.221	38.864
L	TOTAL DIRECT COST	,$/KWE	138.271	139.685	140.758	144.065	169.010	176.317	196.954	215.031
T	INDIRECT COSTS	,$/KWE	13.721	13.496	13.125	13.471	17.180	17.542	18.503	19.821
	PROF & OWNER COSTS	,$/KWE	11.052	11.095	11.251	11.525	13.521	14.153	15.756	17.282
B	CONTINGENCY COST	,$/KWE	9.952	9.941	10.026	10.194	9.899	10.273	11.326	12.291
R	ESCALATION COST	,$/KWE	23.237	23.083	29.055	29.374	23.464	24.045	26.078	27.871
E	INT DURING CONSTRUCTION	,$/KWE	32.813	32.575	32.505	32.799	25.147	25.726	27.849	29.702
A	TOTAL CAPITALIZATION	,$/KWE	235.097	234.877	235.739	241.429	258.222	268.557	295.467	322.998
K	COST OF ELEC-CAPITAL	,MILLS/KWE	7.432	7.425	7.484	7.632	8.163	8.493	9.372	10.211
D	COST OF ELEC-FUEL	,MILLS/KWE	18.305	17.915	18.035	18.425	21.379	21.310	21.794	27.664
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.588	.585	.584	.583	.598	.594	.592	.592
W	TOTAL COST OF ELEC	,MILLS/KWE	26.325	25.925	26.163	26.640	30.140	30.397	31.758	[illegible]
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	28.666	28.263	28.519	29.041	32.700	33.056	34.681	36.641
	COE 0.8 CAP. FACTOR	,MILLS/KWE	24.857	24.458	24.695	25.135	28.535	28.730	29.926	31.478
	COE 1.2XCAP. COST	,MILLS/KWE	27.811	27.410	27.660	28.167	31.772	32.096	33.632	35.509
	COE 1.2XFUEL COST	,MILLS/KWE	29.936	29.508	29.732	30.325	34.416	34.659	35.117	38.000
	COE (CONTINGENCY=0)	,MILLS/KWE	25.897	25.498	25.734	26.206	29.754	29.999	31.320	32.994
	COE (ESCALATION=0)	,MILLS/KWE	25.272	24.879	25.119	25.587	28.330	29.569	30.861	32.510

	PARAMETRIC POINT		57	58	59	60	61	62	63	64
	TOTAL CAPITAL COST	,M$	84.31	80.17	78.18	74.50	97.28	88.02	83.64	107.34
P	GAS TURBINE COMPRESSOR SECT	,M$	2.230	2.414	4.169	4.453	2.230	4.169	4.453	2.230
L	GAS TURBINE COMB BASKETS	,M$	.574	.647	.676	.679	.607	.712	.715	.640
A	GAS TURBINE TURBINE SECTION	,M$	4.268	4.725	5.057	5.277	5.174	5.311	5.547	5.379
N	MISC GAS TURBINE AUXILIARY	,M$	4.885	4.965	4.837	4.628	5.343	5.432	5.245	5.944
T	GAS TURBINE GENERATOR	,M$	4.435	4.515	4.387	4.173	4.893	4.981	4.796	5.477
	STEAM TURBINE GENERATOR	,M$	6.415	5.331	4.479	3.904	7.725	5.471	4.845	8.017
	HEAT RECOVERY STEAM GEN	,M$	9.220	8.320	7.430	6.910	11.244	8.450	7.690	13.260
R	TOT MAJOR COMPONENT COST	,M$	32.026	30.917	31.095	30.023	37.216	34.526	33.292	40.946
E	TOT MAJOR COMPONENT COST	,$/KWE	91.275	95.295	105.239	112.245	91.257	96.747	101.369	88.526
S	BALANCE OF PLANT COST	,$/KWE	33.828	34.550	36.037	37.724	32.485	33.573	34.346	30.970
U	SITE LABOR	,$/KWE	31.011	31.453	32.597	34.055	30.350	30.433	31.057	29.533
L	TOTAL DIRECT COST	,$/KWE	156.114	161.308	174.024	184.025	154.092	160.754	166.771	149.029
T	INDIRECT COSTS	,$/KWE	15.815	16.046	16.670	17.368	15.478	15.521	15.833	15.062
	PROF & OWNER COSTS	,$/KWE	12.489	12.905	13.922	14.722	12.327	12.860	13.342	11.922
B	CONTINGENCY COST	,$/KWE	9.231	9.535	10.204	10.700	9.292	9.581	9.868	9.087
R	ESCALATION COST	,$/KWE	22.446	22.812	24.102	24.985	22.782	23.093	23.550	22.579
E	INT DURING CONSTRUCTION	,$/KWE	24.132	24.432	25.336	26.739	[illegible]	24.835	25.290	24.395
A	TOTAL CAPITALIZATION	,$/KWE	240.288	247.098	264.757	278.536	238.532	246.642	254.659	232.075
K	COST OF ELEC-CAPITAL	,MILLS/KWE	7.596	7.811	8.370	8.805	7.541	7.797	8.050	7.336
D	COST OF ELEC-FUEL	,MILLS/KWE	20.375	20.171	20.502	21.040	19.741	19.552	19.959	19.299
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.596	.592	.591	.590	.595	.589	.588	.594
W	TOTAL COST OF ELEC	,MILLS/KWE	28.567	28.574	29.462	30.435	27.876	27.938	28.597	27.230
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	30.957	31.029	32.085	33.189	30.250	30.388	31.124	29.542
	COE 0.8 CAP. FACTOR	,MILLS/KWE	27.068	27.035	27.818	28.709	26.388	26.401	27.013	25.779
	COE 1.2XCAP. COST	,MILLS/KWE	30.036	30.137	31.135	32.195	29.395	29.497	30.207	28.697
	COE 1.2XFUEL COST	,MILLS/KWE	32.642	32.608	33.563	34.643	31.825	31.848	32.589	31.089
	COE (CONTINGENCY=0)	,MILLS/KWE	28.203	28.202	29.055	30.019	27.510	27.562	28.211	26.870
	COE (ESCALATION=0)	,MILLS/KWE	27.790	27.786	28.630	29.573	27.080	27.138	27.783	26.444

Table 6.8 COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT	65	66	67	68	69	70	71	72
	TOTAL CAPITAL COST ,M$	101.35	95.73	93.48	113.17	111.24	108.54	102.10	235.16
P	GAS TURBINE COMPRESSOR SECT,M$	2.414	4.169	4.453	2.230	2.414	4.169	4.454	4.459
L	GAS TURBINE COMB BASKETS ,M$	.713	.749	.750	.573	.755	.785	.785	1.213
A	GAS TURBINE TURBINE SECTION,M$	5.957	5.550	5.803	5.586	5.248	6.724	6.062	16.458
N	MISC GAS TURBINE AUXILIARY ,M$	5.049	5.022	5.355	6.258	6.609	6.537	5.514	11.425
T	GAS TURBINE GENERATOR ,M$	5.578	5.552	5.402	5.775	6.104	6.131	6.016	10.508
	STEAM TURBINE GENERATOR ,M$	7.573	5.373	5.757	9.392	9.084	7.112	6.754	13.742
	HEAT RECOVERY STEAM GEN ,M$	10.340	9.200	6.700	11.860	12.330	10.780	9.260	30.520
R	TOT MAJOR COMPONENT COST ,M$	35.170	37.614	35.742	42.364	42.543	42.339	39.846	88.325
E	TOT MAJOR COMPONENT COST,$/KWE	98.311	90.114	94.302	83.172	85.105	89.097	88.707	96.040
S	BALANCE OF PLANT COST ,$/KWE	31.061	31.442	32.342	30.957	29.719	30.284	30.577	27.767
U	SITE LABOR ,$/KWE	28.750	28.453	29.258	27.995	27.789	27.818	27.519	28.416
L	TOTAL DIRECT COST ,$/KWE	143.128	150.009	155.902	142.123	142.614	147.199	146.803	152.224
T	INDIRECT COSTS ,$/KWE	14.656	14.511	14.921	14.277	14.173	14.187	14.035	14.492
	PROF & OWNER COSTS ,$/KWE	11.850	12.001	12.472	11.370	11.409	11.775	11.744	12.178
B	CONTINGENCY COST ,$/KWE	8.998	9.063	9.362	8.743	8.756	8.996	8.927	10.790
R	ESCALATION COST ,$/KWE	22.274	22.203	22.755	21.929	21.896	22.325	22.013	31.183
E	INT DURING CONSTRUCTION ,$/KWE	23.993	23.944	24.509	23.736	23.690	24.134	23.770	34.833
A	TOTAL CAPITALIZATION ,$/KWE	229.353	231.731	239.922	222.178	222.537	228.618	227.291	255.700
K	COST OF ELEC-CAPITAL,MILLS/KWE	7.266	7.320	7.584	7.024	7.035	7.227	7.185	8.083
D	COST OF ELEC-FUEL ,MILLS/KWE	18.813	18.855	19.155	19.200	18.423	18.401	18.567	18.738
O	COST OF ELEC-OP&MAIN,MILLS/KWE	.590	.588	.587	.604	.589	.587	.586	.589
W	TOTAL COST OF ELEC ,MILLS/KWE	26.669	26.758	27.326	26.828	26.047	25.215	26.337	27.410
N	COE 0.5 CAP. FACTOR ,MILLS/KWE	28.961	29.077	29.713	29.047	28.269	28.495	28.604	29.946
	COE 0.8 CAP. FACTOR ,MILLS/KWE	25.232	25.320	25.829	25.437	24.653	24.785	24.915	25.820
	COE 1.2XCAP. COST ,MILLS/KWE	28.123	28.233	28.843	28.233	27.454	27.661	27.774	29.026
	COE 1.2XFUEL COST ,MILLS/KWE	30.432	30.539	31.157	30.663	29.732	29.896	30.051	31.157
	COE (CONTINGENCY=0) ,MILLS/KWE	26.313	26.410	26.957	26.480	25.699	25.859	25.994	26.950
	COE (ESCALATION=0) ,MILLS/KWE	25.837	25.997	26.537	26.064	25.295	25.439	25.572	26.292

	PARAMETRIC POINT	73	74	75	76	77	78	79	80
	TOTAL CAPITAL COST ,M$	216.12	209.39	200.30	252.72	243.02	232.14	222.33	Not calculated
P	GAS TURBINE COMPRESSOR SECT,M$	4.827	8.333	8.807	4.459	4.827	8.338	8.907	
L	GAS TURBINE COMB BASKETS ,M$	1.366	1.424	1.430	1.213	1.366	1.424	1.430	
A	GAS TURBINE TURBINE SECTION,M$	18.551	18.418	19.339	21.253	24.295	25.892	27.368	
N	MISC GAS TURBINE AUXILIARY ,M$	11.862	11.774	11.440	11.969	12.484	12.451	12.146	
T	GAS TURBINE GENERATOR ,M$	10.923	10.845	10.522	11.032	11.521	11.490	11.201	
	STEAM TURBINE GENERATOR ,M$	10.648	9.452	8.450	13.667	11.061	9.910	8.884	
	HEAT RECOVERY STEAM GEN ,M$	23.420	20.920	18.500	32.200	28.240	22.480	19.560	
R	TOT MAJOR COMPONENT COST ,M$	81.712	81.171	78.737	95.793	93.784	91.965	89.495	
E	TOT MAJOR COMPONENT COST,$/KWE	95.157	102.170	105.950	97.740	102.374	107.556	112.418	
S	BALANCE OF PLANT COST ,$/KWE	28.377	28.857	29.788	27.292	27.827	28.190	28.849	
U	SITE LABOR ,$/KWE	27.252	27.923	28.325	28.102	28.136	27.695	27.897	
L	TOTAL DIRECT COST ,$/KWE	150.786	158.950	165.063	153.134	158.038	163.451	169.164	
T	INDIRECT COSTS ,$/KWE	13.993	14.241	14.445	14.332	14.350	14.125	14.227	
	PROF & OWNER COSTS ,$/KWE	12.054	12.716	13.205	12.251	12.643	13.076	13.533	
B	CONTINGENCY COST ,$/KWE	10.614	11.101	11.441	10.924	11.200	11.500	11.817	
R	ESCALATION COST ,$/KWE	30.401	31.494	32.167	31.722	32.249	32.770	33.379	
E	INT DURING CONSTRUCTION ,$/KWE	33.903	35.058	35.743	35.490	36.022	36.541	37.158	
A	TOTAL CAPITALIZATION ,$/KWE	251.682	263.561	272.064	257.853	264.502	271.462	279.278	
K	COST OF ELEC-CAPITAL,MILLS/KWE	7.956	8.332	8.601	8.151	8.361	8.582	8.829	
D	COST OF ELEC-FUEL ,MILLS/KWE	18.586	18.793	19.063	18.430	18.204	18.297	18.477	
O	COST OF ELEC-OP&MAIN,MILLS/KWE	.587	.585	.585	.588	.585	.584	.584	
W	TOTAL COST OF ELEC ,MILLS/KWE	27.128	27.710	28.249	27.169	27.151	27.463	27.890	
N	COE 0.5 CAP. FACTOR ,MILLS/KWE	29.626	30.321	30.941	29.725	29.771	30.149	30.650	
	COE 0.8 CAP. FACTOR ,MILLS/KWE	25.562	26.073	26.562	25.566	25.508	25.779	26.160	
	COE 1.2XCAP. COST ,MILLS/KWE	28.719	29.376	29.959	28.799	28.823	29.179	29.656	
	COE 1.2XFUEL COST ,MILLS/KWE	30.845	31.469	32.062	30.855	30.792	31.122	31.585	
	COE (CONTINGENCY=0) ,MILLS/KWE	26.673	27.241	27.757	26.702	26.674	26.975	27.390	
	COE (ESCALATION=0) ,MILLS/KWE	26.040	26.584	27.101	26.030	25.994	26.290	26.697	

Table 6.8 COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS
Continued

PARAMETRIC POINT	81	82	83	84	85	86	87	88
TOTAL CAPITAL COST ,M$	Not calculated			195.09				
P GAS TURBINE COMPRESSOR SECT,M$				4.827				
L GAS TURBINE COMB BASKETS ,M$				1.365				
A GAS TURBINE TURBINE SECTION,M$				10.039				
N MISC GAS TURBINE AUXILIARY ,M$				11.841				
T GAS TURBINE GENERATOR ,M$				10.451				
STEAM TURBINE GENERATOR ,M$				10.393				
HEAT RECOVERY STEAM GEN ,M$				23.600				
R TOT MAJOR COMPONENT COST ,M$				72.513				
E TOT MAJOR COMPONENT COST,$/KWE				90.457				
S BALANCE OF PLANT COST ,$/KWE				28.426				
U SITE LABOR ,$/KWE				27.745				
L TOTAL DIRECT COST ,$/KWE				146.627				
T INDIRECT COSTS ,$/KWE				14.150				
PROF & OWNER COSTS ,$/KWE				11.730				
B CONTINGENCY COST ,$/KWE				10.250				
R ESCALATION COST ,$/KWE				29.258				
E INT DURING CONSTRUCTION ,$/KWE				32.587				
A TOTAL CAPITALIZATION ,$/KWE				244.613				
K COST OF ELEC-CAPITAL,MILLS/KWE				7.733				
D COST OF ELEC-FUEL ,MILLS/KWE				20.077				
O COST OF ELEC-OP&MAIN,MILLS/KWE				.588				
W TOTAL COST OF ELEC ,MILLS/KWE				28.397				
N COE 0.5 CAP. FACTOR ,MILLS/KWE				30.823				
COE 0.8 CAP. FACTOR ,MILLS/KWE				26.873				
COE 1.2XCAP. COST ,MILLS/KWE				29.944				
COE 1.2XFUEL COST ,MILLS/KWE				32.413				
COE (CONTINGENCY=0) ,MILLS/KWE				27.964				
COE (ESCALATION=0) ,MILLS/KWE				27.351				

PARAMETRIC POINT	89	90	91	92	93	94	95	96
TOTAL CAPITAL COST ,M$	205.88	205.94	184.87	.00	.00	.00	.00	.00
P GAS TURBINE COMPRESSOR SECT,M$	4.827	4.827	4.827	.000	.000	.000	.000	.000
L GAS TURBINE COMB BASKETS ,M$	1.366	1.366	1.366	.000	.000	.000	.000	.000
A GAS TURBINE TURBINE SECTION,M$	9.902	9.902	9.902	.000	.000	.000	.000	.000
N MISC GAS TURBINE AUXILIARY ,M$	11.020	11.020	11.020	.000	.000	.000	.000	.000
T GAS TURBINE GENERATOR ,M$	10.115	10.115	10.115	.000	.000	.000	.000	.000
STEAM TURBINE GENERATOR ,M$	10.956	11.774	9.561	.000	.000	.000	.000	.000
HEAT RECOVERY STEAM GEN ,M$	29.492	27.564	21.628	.000	.000	.000	.000	.000
R TOT MAJOR COMPONENT COST ,M$	76.678	76.567	68.419	.000	.000	.000	.000	.000
E TOT MAJOR COMPONENT COST,$/KWE	97.355	97.610	91.745	.000	.000	.000	.000	.000
S BALANCE OF PLANT COST ,$/KWE	28.916	29.264	28.938	.000	.000	.000	.000	.000
U SITE LABOR ,$/KWE	30.590	30.420	28.441	.000	.000	.000	.000	.000
L TOTAL DIRECT COST ,$/KWE	157.361	157.294	149.125	.000	.000	.000	.000	.000
T INDIRECT COSTS ,$/KWE	15.601	15.514	14.505	.000	.000	.000	.000	.000
PROF & OWNER COSTS ,$/KWE	12.589	12.584	11.930	.000	.000	.000	.000	.000
B CONTINGENCY COST ,$/KWE	10.976	10.973	10.349	.000	.000	.000	.000	.000
R ESCALATION COST ,$/KWE	31.337	31.320	29.360	.000	.000	.000	.000	.000
E INT DURING CONSTRUCTION ,$/KWE	34.872	34.854	32.633	.000	.000	.000	.000	.000
A TOTAL CAPITALIZATION ,$/KWE	262.735	262.538	247.902	.000	.000	.000	.000	.000
K COST OF ELEC-CAPITAL,MILLS/KWE	8.306	8.299	7.837	.000	.000	.000	.000	.000
D COST OF ELEC-FUEL ,MILLS/KWE	19.025	19.009	20.002	.000	.000	.000	.000	.000
O COST OF ELEC-OP&MAIN,MILLS/KWE	.585	.590	.581	.000	.000	.000	.000	.000
W TOTAL COST OF ELEC ,MILLS/KWE	27.916	27.898	28.420	.000	.000	.000	.000	.000
N COE 0.5 CAP. FACTOR ,MILLS/KWE	30.519	30.499	30.332	.000	.000	.000	.000	.000
COE 0.8 CAP. FACTOR ,MILLS/KWE	26.284	26.267	26.876	.000	.000	.000	.000	.000
COE 1.2XCAP. COST ,MILLS/KWE	29.577	29.558	29.937	.000	.000	.000	.000	.000
COE 1.2XFUEL COST ,MILLS/KWE	31.721	31.700	32.420	.000	.000	.000	.000	.000
COE (CONTINGENCY=0) ,MILLS/KWE	27.452	27.434	27.983	.000	.000	.000	.000	.000
COE (ESCALATION=0) ,MILLS/KWE	26.796	26.779	27.371	.000	.000	.000	.000	.000

6.6 Analysis of Overall Cost of Electricity

The results of capital cost determinations, thermodynamic efficiency calculations, as well as the results of the analysis of coal-derived fuel prices and balance of plant costs, have been factored into the COE calculations for the parametric variations described in the earlier sections. Table 6.9 presents a summary of these COE for each parametric point investigated.

In preparing the COE results, a more detailed examination was made of the effects of selected parameters on the results. Parameters for which these variations were investigated include: labor rate, contingency, escalation rate, interest during construction, fixed charge rate, fuel cost, and capacity factor. The results of these studies for Base Cases A and B are given in Tables 6.10 and 6.11.

The COE has been calculated as a function of several cycle parameters, including gas turbine compressor pressure ratio, turbine inlet temperature, and the nominal steam cycle throttle conditions. The use of steam induction and supplementary heat recovery steam generator firing has been investigated. In addition, variations in the methods of steam cycle heat rejection and comparisons of the use of gasified coal and clean distillate from coal as a fuel have been analyzed.

COE calculations were made for turbine inlet temperature variations from 1255 to 1700°K (1800 to 2600°F) and for compressor pressure ratio values ranging from 8 to 20. These variations in gas turbine parameters were investigated in conjunction with each of two steam bottoming cycles: first, a reheat 16.547 MPa/811°K/811°K (2400 psig/1000°F/1000°F) arrangement and, second, a nonreheat cycle with nominal throttle conditions of 8.618 MPa/783°K (1250 psig/950°F). Results of these calculations, for the cases with air-cooled gas turbine vanes and blades, are shown in Figure 6.32. As indicated, the COE steadily decreases as gas turbine inlet temperature increases, with a small COE advantage at lower temperature obtained with the nonreheat steam cycle.

Table 6.9 COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	not calculated	.000	.000
POWER PLANT EFF	.436	.459	.464	.472	.474		.465	.459
OVERALL ENERGY EFF	.436	.231	.234	.238	.239		.235	.232
CAP COST MILLION $	389.066	89.841	92.436	195.795	206.806		198.100	190.377
CAPITAL COST,$/KWE	495.559	233.125	236.951	245.717	259.935		253.372	246.766
COE CAPITAL	15.697	7.370	7.491	7.799	8.217		8.010	7.801
COE FUEL	5.952	19.342	19.133	18.792	18.733		19.073	19.325
COE OP & MAIN	1.702	.591	.591	.589	.588		.588	.589
COST OF ELECTRIC	24.251	27.303	27.190	27.180	27.538		27.670	27.715
EST TIME OF CONST	4.000	3.000	3.006	3.984	3.986		3.973	3.964

PARAMETRIC POINT	9	10	11	12	13	14	15	16
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.462	.461	.459	.464	.446	.467	.432	.475
OVERALL ENERGY EFF	.233	.232	.231	.234	.225	.235	.218	.240
CAP COST MILLION $	191.922	192.798	191.014	196.270	183.586	188.334	193.603	216.125
CAPITAL COST,$/KWE	245.975	249.008	247.711	251.935	244.955	240.213	255.719	270.842
COE CAPITAL	7.807	7.872	7.831	7.964	7.744	7.594	8.432	8.562
COE FUEL	19.188	19.259	19.337	19.139	19.891	19.018	20.543	18.682
COE OP & MAIN	.588	.589	.589	.588	.579	.552	.552	.588
COST OF ELECTRIC	27.583	27.719	27.757	27.691	28.214	27.164	29.525	27.832
EST TIME OF CONST	3.969	3.967	3.964	3.971	3.943	3.972	3.926	3.988

PARAMETRIC POINT	17	18	19	20	21	22	23	24
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.461	.438	.425	.461	.457	.460	.458	.458
OVERALL ENERGY EFF	.233	.221	.214	.233	.230	.232	.231	.231
CAP COST MILLION $	212.424	205.479	270.251	92.255	88.843	89.945	89.772	89.241
CAPITAL COST,$/KWE	281.932	252.504	254.383	238.035	231.374	232.787	233.434	231.925
COE CAPITAL	8.912	8.298	8.358	7.525	7.314	7.359	7.379	7.332
COE FUEL	19.237	20.252	20.900	19.234	19.418	19.295	19.389	19.375
COE OP & MAIN	.636	.609	.615	.590	.591	.591	.591	.591
COST OF ELECTRIC	28.734	29.159	29.873	27.349	27.323	27.245	27.359	27.298
EST TIME OF CONST	4.448	4.972	5.238	3.003	2.998	3.001	2.999	2.999

PARAMETRIC POINT	25	26	27	28	29	30	31	32
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.460	.453	.465	.427	.457	.444	.396	.377
OVERALL ENERGY EFF	.232	.229	.234	.215	.230	.224	.200	.190
CAP COST MILLION $	91.444	88.122	87.691	99.286	90.573	122.577	100.673	134.627
CAPITAL COST,$/KWE	235.799	231.534	224.619	249.084	235.940	265.158	284.631	288.060
COE CAPITAL	7.486	7.319	7.101	7.874	7.459	8.414	8.999	9.106
COE FUEL	19.309	19.583	19.100	20.798	19.419	19.971	22.404	23.519
COE OP & MAIN	.591	.588	.552	.552	.592	.599	.621	.631
COST OF ELECTRIC	27.385	27.490	26.753	29.223	27.470	28.984	32.023	33.256
EST TIME OF CONST	3.001	2.993	3.004	2.965	2.998	3.612	3.945	4.143

PARAMETRIC POINT	33	34	35	36	37	38	39	40
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.415	.414	.403	.386	.440	.439	.431	.418
OVERALL ENERGY EFF	.209	.209	.203	.195	.222	.222	.217	.211
CAP COST MILLION $	156.788	147.218	143.999	137.258	181.420	167.166	163.129	155.373
CAPITAL COST,$/KWE	269.330	281.343	310.409	337.565	255.731	257.909	277.422	292.743
COE CAPITAL	8.516	8.894	9.813	10.671	8.086	8.153	8.770	9.254
COE FUEL	21.339	21.445	22.036	23.005	20.162	20.200	20.599	21.213
COE OP & MAIN	.597	.594	.593	.594	.593	.591	.590	.590
COST OF ELECTRIC	30.511	30.934	32.442	34.270	28.841	28.944	29.960	31.059
EST TIME OF CONST	3.774	3.704	3.627	3.544	3.907	3.845	3.780	3.713

Table 6.9
Continued

COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS

PARAMETRIC POINT	41	42	43	44	45	46	47	48
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.461	.452	.453	.443	.476	.481	.473	.463
OVERALL ENERGY EFF	.232	.233	.223	.224	.240	.242	.239	.234
CAP COST MILLION $	200.902	192.420	183.817	175.350	235.566	220.942	207.097	195.692
CAPITAL COST,$/KWE	240.231	248.131	257.822	267.397	245.845	244.412	245.552	251.174
COE CAPITAL	7.590	7.844	8.150	8.469	7.772	7.726	7.794	7.940
COE FUEL	19.253	19.221	19.530	20.024	18.628	18.452	18.744	19.155
COE OP & MAIN	.590	.589	.589	.588	.589	.586	.585	.586
COST OF ELECTRIC	27.444	27.653	28.304	29.081	26.989	26.775	27.124	27.682
EST TIME OF CONST	4.021	3.968	3.910	3.852	4.118	4.075	4.023	3.971

PARAMETRIC POINT	49	50	51	52	53	54	55	56
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.485	.495	.490	.482	.415	.416	.407	.392
OVERALL ENERGY EFF	.246	.250	.247	.243	.209	.210	.205	.197
CAP COST MILLION $	251.238	241.477	228.807	213.611	75.194	70.746	65.592	66.699
CAPITAL COST,$/KWE	235.037	234.877	233.739	241.429	258.222	268.657	296.457	322.998
COE CAPITAL	7.432	7.425	7.484	7.632	8.163	8.493	9.372	10.211
COE FUEL	18.335	17.915	18.095	18.425	21.373	21.310	21.794	22.664
COE OP & MAIN	.588	.595	.584	.583	.598	.594	.592	.592
COST OF ELECTRIC	26.325	25.925	26.163	26.640	30.140	30.397	31.759	33.467
EST TIME OF CONST	4.197	4.168	4.123	4.076	2.857	2.807	2.751	2.690

PARAMETRIC POINT	57	58	59	60	61	62	63	64
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.435	.440	.433	.422	.449	.454	.445	.460
OVERALL ENERGY EFF	.220	.222	.218	.213	.227	.229	.224	.232
CAP COST MILLION $	84.312	80.166	78.183	74.503	97.276	88.018	83.636	107.342
CAPITAL COST,$/KWE	240.293	247.399	264.757	278.535	233.532	246.642	254.659	232.075
COE CAPITAL	7.596	7.811	8.370	8.805	7.541	7.797	8.050	7.336
COE FUEL	20.375	20.171	20.502	21.040	19.741	19.552	19.959	19.239
COE OP & MAIN	.590	.592	.591	.590	.595	.589	.588	.594
COST OF ELECTRIC	28.557	28.574	29.462	30.435	27.876	27.938	28.597	27.230
EST TIME OF CONST	2.952	2.911	2.863	2.814	3.030	2.960	2.917	3.098

PARAMETRIC POINT	65	66	67	68	69	70	71	72
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.472	.471	.463	.462	.482	.482	.478	.474
OVERALL ENERGY EFF	.238	.237	.234	.233	.243	.243	.241	.239
CAP COST MILLION $	101.952	96.726	93.477	113.168	111.243	108.638	102.095	235.159
CAPITAL COST,$/KWE	229.953	231.731	239.922	222.178	222.537	228.618	227.291	255.700
COE CAPITAL	7.266	7.326	7.584	7.024	7.035	7.227	7.185	8.083
COE FUEL	18.913	18.955	19.155	19.200	18.423	18.401	18.567	18.739
COE OP & MAIN	.590	.588	.587	.604	.589	.587	.585	.589
COST OF ELECTRIC	26.553	26.759	27.325	26.828	26.047	26.215	26.337	27.410
EST TIME OF CONST	3.075	3.042	3.005	3.151	3.140	3.112	3.081	4.088

PARAMETRIC POINT	73	74	75	76	77	78	79	80
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	t calculated
POWER PLANT EFF	.477	.472	.465	.481	.487	.485	.480	
OVERALL ENERGY EFF	.241	.233	.235	.243	.245	.245	.242	
CAP COST MILLION $	216.121	209.393	200.295	232.718	243.019	232.140	222.330	
CAPITAL COST,$/KWE	251.532	263.551	272.054	257.853	264.502	271.452	273.273	
COE CAPITAL	7.956	8.332	8.601	8.151	8.361	8.582	8.829	
COE FUEL	18.585	18.793	19.053	18.430	18.204	18.237	18.477	
COE OP & MAIN	.586	.586	.586	.588	.585	.584	.584	
COST OF ELECTRIC	27.129	27.710	28.249	27.169	27.151	27.453	27.890	
EST TIME OF CONST	4.039	3.984	3.931	4.134	4.087	4.036	3.985	

Table 6.9 Continued

COMBINED GAS-STEAM TURBINE CYCLE SUMMARY PLANT RESULTS

PARAMETRIC POINT	81	82	83	84	85	86	87	88
THERMODYNAMIC EFF				.000				
POWER PLANT EFF				.442	.411	.454	.378	
OVERALL ENERGY EFF				.297	.411	.454	.378	
CAP COST MILLION $		Not calculated		136.089				
CAPITAL COST,$/KWE				244.613				
COE CAPITAL				7.733				
COE FUEL				30.077				
COE OP & MAIN				.588				
COST OF ELECTRIC				38.397				
EST TIME OF CONST				3.991				

PARAMETRIC POINT	89	90	91	92	93	94	95	96
THERMODYNAMIC EFF	.000	.000	.000	.000	.000	.000	.000	.000
POWER PLANT EFF	.466	.467	.444	.000	.000	.000	.000	.000
OVERALL ENERGY EFF	.235	.235	.224	.000	.000	.000	.000	.000
CAP COST MILLION $	205.877	205.940	164.872	.000	.000	.000	.000	.000
CAPITAL COST,$/KWE	252.735	252.533	247.332	.000	.000	.000	.000	.000
COE CAPITAL	8.306	8.299	7.837	.000	.000	.000	.000	.000
COE FUEL	19.325	19.009	20.002	.000	.000	.000	.000	.000
COE OP & MAIN	.536	.590	.581	.000	.000	.000	.000	.000
COST OF ELECTRIC	27.915	27.899	28.420	.000	.000	.000	.000	.000
EST TIME OF CONST	3.975	3.976	3.940	.000	.000	.000	.000	.000

Table 6.10 COMBINED GAS-STEAM TURBINE CYCLE COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO. 1

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	199274864.	213507392.	225646714.	250871952.	288136532.
INDIRECT COST,$	51.0	17543013.	24852602.	30992656.	43857532.	62862464.
PROF & OWNER COSTS,$	8.0	15941389.	17083591.	18051737.	20059757.	23050922.
CONTINGENCY COST,$	7.0	13949240.	14952517.	15795270.	17561037.	20169557.
SUB TOTAL,$	.0	246709104.	270501130.	290486372.	332350284.	394219472.
ESCALATION COST,$	6.5	39600173.	43428980.	46637618.	53360479.	63291978.
INTREST DURING CONST,$	10.0	44114447.	48353732.	51942330.	59429871.	70491011.
TOTAL CAPITALIZATION,$	.0	330432720.	362298812.	389066316.	445150628.	528002456.
COST OF ELEC-CAPITAL	18.0	13.33170	14.61739	15.69734	17.96013	21.30289
COST OF ELEC-FUEL	.0	6.85191	6.85191	6.85191	6.85191	6.85191
COST OF ELEC-OP & MAIN	.0	1.70152	1.70152	1.70152	1.70152	1.70152
TOTAL COST OF ELEC	.0	21.88513	23.17080	24.25077	26.51356	29.85631

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	7.00	5.00	20.00
TOTAL DIRECT COSTS,$	.0	225646714.	225646714.	225646714.	225646714.	225646714.
INDIRECT COST,$	51.0	30992656.	30992656.	30992656.	30992656.	30992656.
PROF & OWNER COSTS,$	8.0	18051737.	18051737.	18051737.	18051737.	18051737.
CONTINGENCY COST,$	20.0	-11282335.	0.	15795270.	11282336.	45129342.
SUB TOTAL,$	.0	263408772.	274691104.	290486372.	285973436.	319820444.
ESCALATION COST,$	5.5	42290306.	44101685.	46637618.	45913066.	51347206.
INTREST DURING CONST,$	10.0	47100541.	49117953.	51942330.	51135365.	57187802.
TOTAL CAPITALIZATION,$	.0	352799616.	357910740.	389066316.	383021864.	428355248.
COST OF ELEC-CAPITAL	18.0	14.23412	14.84380	15.69734	15.45347	17.29250
COST OF ELEC-FUEL	.0	6.85191	6.85191	6.85191	6.85191	6.85191
COST OF ELEC-OP & MAIN	.0	1.70152	1.70152	1.70152	1.70152	1.70152
TOTAL COST OF ELEC	.0	22.78755	23.39722	24.25077	24.00690	25.83593

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	225646714.	225646714.	225646714.	225646714.	225646714.
INDIRECT COST,$	51.0	30992656.	30992656.	30992656.	30992656.	30992656.
PROF & OWNER COSTS,$	8.0	18051737.	18051737.	18051737.	18051737.	18051737.
CONTINGENCY COST,$	7.0	15795270.	15795270.	15795270.	15795270.	15795270.
SUB TOTAL,$	.0	290486372.	290486372.	290486372.	290486372.	290486372.
ESCALATION COST,$	.0	35449325.	46637618.	58087213.	73765717.	0.
INTREST DURING CONST,$	10.0	50485226.	51942330.	53425849.	55445363.	45816237.
TOTAL CAPITALIZATION,$	.0	376420920.	389066316.	401999432.	419697448.	336302608.
COST OF ELEC-CAPITAL	18.0	15.18715	15.69734	16.21915	16.93319	13.56853
COST OF ELEC-FUEL	.0	6.85191	6.85191	6.85191	6.85191	6.85191
COST OF ELEC-OP & MAIN	.0	1.70152	1.70152	1.70152	1.70152	1.70152
TOTAL COST OF ELEC	.0	23.74058	24.25077	24.77257	25.48662	22.12195

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 5.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	225646714.	225646714.	225646714.	225646714.	225646714.
INDIRECT COST,$	51.0	30992656.	30992656.	30992656.	30992656.	30992656.
PROF & OWNER COSTS,$	8.0	18051737.	18051737.	18051737.	18051737.	18051737.
CONTINGENCY COST,$	7.0	15795270.	15795270.	15795270.	15795270.	15795270.
SUB TOTAL,$	.0	290486372.	290486372.	290486372.	290486372.	290486372.
ESCALATION COST,$	5.5	46637618.	46637618.	46637618.	46637618.	46637618.
INTREST DURING CONST,$	15.0	30636288.	41200004.	51942330.	55623837.	79590190.
TOTAL CAPITALIZATION,$	.0	367760272.	378323992.	389066316.	402747824.	416714176.
COST OF ELEC-CAPITAL	18.0	14.93773	15.26393	15.69734	16.24934	16.81283
COST OF ELEC-FUEL	.0	6.85191	6.85191	6.85191	6.85191	6.85191
COST OF ELEC-OP & MAIN	.0	1.70152	1.70152	1.70152	1.70152	1.70152
TOTAL COST OF ELEC	.0	23.39115	23.81735	24.25077	24.80277	25.35626

Table 6.10 COMBINED GAS-STEAM TURBINE CYCLE COST OF ELECTRICITY,MILLS/KW.HR
Continued
PARAMETRIC POINT NO. 1

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	225646714.	225646714.	225646714.	225646714.	225646714.
INDIRECT COST,$	51.0	30992656.	30992656.	30992656.	30992656.	30992656.
PROF & OWNER COSTS,$	8.0	18051737.	18051737.	18051737.	18051737.	18051737.
CONTINGENCY COST,$	7.0	15795270.	15795270.	15795270.	15795270.	15795270.
SUB TOTAL,$	.0	290486372.	290486372.	290486372.	290486372.	290486372.
ESCALATION COST,$	6.5	46637618.	46637618.	46637618.	46637618.	46637618.
INTREST DURING CONST,$	10.0	51942330.	51942330.	51942330.	51942330.	51942330.
TOTAL CAPITALIZATION,$	.0	389066316.	389066316.	389066316.	389066316.	389066316.
COST OF ELEC-CAPITAL	25.0	8.72075	12.55788	15.69734	18.83681	21.80187
COST OF ELEC-FUEL	.0	6.85191	6.85191	6.85191	6.85191	6.85191
COST OF ELEC-OP & MAIN	.0	1.70152	1.70152	1.70152	1.70152	1.70152
TOTAL COST OF ELEC	.0	17.27417	21.11130	24.25077	27.39024	30.35529

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	225646714.	225646714.	225646714.	225646714.	225646714.
INDIRECT COST,$	51.0	30992656.	30992656.	30992656.	30992656.	30992656.
PROF & OWNER COSTS,$	8.0	18051737.	18051737.	18051737.	18051737.	18051737.
CONTINGENCY COST,$	7.0	15795270.	15795270.	15795270.	15795270.	15795270.
SUB TOTAL,$	.0	290486372.	290486372.	290486372.	290486372.	290486372.
ESCALATION COST,$	6.5	46637618.	46637618.	46637618.	46637618.	46637618.
INTREST DURING CONST,$	10.0	51942330.	51942330.	51942330.	51942330.	51942330.
TOTAL CAPITALIZATION,$	.0	389066316.	389066316.	389066316.	389066316.	389066316.
COST OF ELEC-CAPITAL	18.0	15.69734	15.69734	15.69734	15.69734	15.69734
COST OF ELEC-FUEL	.0	4.03053	6.85191	12.09160	20.15267	8.22229
COST OF ELEC-OP & MAIN	.0	1.70152	1.70152	1.70152	1.70152	1.70152
TOTAL COST OF ELEC	.0	21.42940	24.25077	29.49046	37.55153	25.62115

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	225646714.	225646714.	225646714.	225646714.	225646714.
INDIRECT COST,$	51.0	30992656.	30992656.	30992656.	30992656.	30992656.
PROF & OWNER COSTS,$	8.0	18051737.	18051737.	18051737.	18051737.	18051737.
CONTINGENCY COST,$	7.0	15795270.	15795270.	15795270.	15795270.	15795270.
SUB TOTAL,$	.0	290486372.	290486372.	290486372.	290486372.	290486372.
ESCALATION COST,$	6.5	46637618.	46637618.	46637618.	46637618.	46637618.
INTREST DURING CONST,$	10.0	51942330.	51942330.	51942330.	51942330.	51942330.
TOTAL CAPITALIZATION,$	.0	389066316.	389066316.	389066316.	389066316.	389066316.
COST OF ELEC-CAPITAL	18.0	85.02728	22.67394	20.40655	15.69734	12.75409
COST OF ELEC-FUEL	.0	6.85191	6.85191	6.85191	6.85191	6.85191
COST OF ELEC-OP & MAIN	.0	2.95658	1.86367	1.81234	1.70152	1.62691
TOTAL COST OF ELEC	.0	94.83577	31.38952	29.07129	24.25077	21.23291

Table 6.11 COMBINED GAS-STEAM TURBINE CYCLE COST OF ELECTRICITY, MILLS/KW.HR
PARAMETRIC POINT NO. 2

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	53291633.	55971965.	58223480.	62940900.	69909814.
INDIRECT COST,$	51.0	3280751.	4647730.	5795993.	8201877.	11756023.
PROF & OWNER COSTS,$	8.0	4263331.	4477759.	4657878.	5035272.	5592785.
CONTINGENCY COST,$	6.0	3197498.	3358319.	3493409.	3776454.	4194589.
SUB TOTAL,$	.0	64033211.	68455792.	72170759.	79954502.	91453210.
ESCALATION COST,$	6.5	7548763.	8070133.	8508084.	9425696.	10781258.
INTREST DURING CONST,$	10.0	8129175.	8690633.	9162257.	10150423.	11610212.
TOTAL CAPITALIZATION,$	.0	79711149.	85216557.	89841100.	99530620.	113844680.
COST OF ELEC-CAPITAL	18.0	6.53865	6.99025	7.36960	8.16442	9.33860
COST OF ELEC-FUEL	.0	19.34223	19.34223	19.34223	19.34223	19.34223
COST OF ELEC-OP & MAIN	.0	.59078	.59078	.59078	.59078	.59078
TOTAL COST OF ELEC	.0	26.47155	26.92325	27.30260	28.09743	29.27160

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	6.00	5.00	20.00
TOTAL DIRECT COSTS,$	.0	58223480.	58223480.	58223480.	58223480.	58223480.
INDIRECT COST,$	51.0	5795993.	5795993.	5795993.	5795993.	5795993.
PROF & OWNER COSTS,$	8.0	4657878.	4657878.	4657878.	4657878.	4657878.
CONTINGENCY COST,$	20.0	-2911174.	0.	3493409.	2911174.	11644696.
SUB TOTAL,$	.0	65766177.	68677351.	72170759.	71588525.	80322047.
ESCALATION COST,$	6.5	7753059.	8096252.	8508084.	8439446.	9469025.
INTREST DURING CONST,$	10.0	8349179.	8718750.	9162257.	9088341.	10197093.
TOTAL CAPITALIZATION,$	.0	81868415.	85492363.	89841100.	89116311.	99988155.
COST OF ELEC-CAPITAL	18.0	6.71561	7.01288	7.36960	7.31015	8.20195
COST OF ELEC-FUEL	.0	19.34223	19.34223	19.34223	19.34223	19.34223
COST OF ELEC-OP & MAIN	.0	.59078	.59078	.59078	.59078	.59078
TOTAL COST OF ELEC	.0	26.64861	26.94588	27.30260	27.24315	28.13496

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	58223480.	58223480.	58223480.	58223480.	58223480.
INDIRECT COST,$	51.0	5795993.	5795993.	5795993.	5795993.	5795993.
PROF & OWNER COSTS,$	8.0	4657878.	4657878.	4657878.	4657878.	4657878.
CONTINGENCY COST,$	6.0	3493409.	3493409.	3493409.	3493409.	3493409.
SUB TOTAL,$	.0	72170759.	72170759.	72170759.	72170759.	72170759.
ESCALATION COST,$	.0	6499551.	8508084.	10545266.	13304975.	0.
INTREST DURING CONST,$	10.0	8968876.	9162257.	9357569.	9620993.	8338226.
TOTAL CAPITALIZATION,$	.0	87638285.	89841100.	92073593.	95096625.	80508985.
COST OF ELEC-CAPITAL	18.0	7.18890	7.36960	7.55273	7.80071	6.60409
COST OF ELEC-FUEL	.0	19.34223	19.34223	19.34223	19.34223	19.34223
COST OF ELEC-OP & MAIN	.0	.59078	.59078	.59078	.59078	.59078
TOTAL COST OF ELEC	.0	27.12191	27.30260	27.48573	27.73371	26.53710

ACCOUNT	RATE, PERCENT	INT DURING CONST, PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	58223480.	58223480.	58223480.	58223480.	58223480.
INDIRECT COST,$	51.0	5795993.	5795993.	5795993.	5795993.	5795993.
PROF & OWNER COSTS,$	8.0	4657878.	4657878.	4657878.	4657878.	4657878.
CONTINGENCY COST,$	6.0	3493409.	3493409.	3493409.	3493409.	3493409.
SUB TOTAL,$	.0	72170759.	72170759.	72170759.	72170759.	72170759.
ESCALATION COST,$	6.5	8508084.	8508084.	8508084.	8508084.	8508084.
INTREST DURING CONST,$	15.0	5453466.	7300519.	9162257.	11510116.	13881055.
TOTAL CAPITALIZATION,$	.0	86132309.	87979360.	89841100.	92188959.	94559898.
COST OF ELEC-CAPITAL	18.0	7.06537	7.21688	7.36960	7.56219	7.75668
COST OF ELEC-FUEL	.0	19.34223	19.34223	19.34223	19.34223	19.34223
COST OF ELEC-OP & MAIN	.0	.59078	.59078	.59078	.59078	.59078
TOTAL COST OF ELEC	.0	26.99837	27.14989	27.30260	27.49520	27.68968

Table 6.11 Continued

COMBINED GAS-STEAM TURBINE CYCLE COST OF ELECTRICITY, MILLS/KW.HR
PARAMETRIC POINT NO. 2

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	58223480.	58223480.	58223480.	58223480.	58223480.
INDIRECT COST,$	51.0	5795993.	5795993.	5795993.	5795993.	5795993.
PROF & OWNER COSTS,$	8.0	4657878.	4657878.	4657878.	4657878.	4657878.
CONTINGENCY COST,$	6.0	3493409.	3493409.	3493409.	3493409.	3493409.
SUB TOTAL,$	.0	72170759.	72170759.	72170759.	72170759.	72170759.
ESCALATION COST,$	6.5	8508084.	8508084.	8508084.	8508084.	8508084.
INTREST DURING CONST,$	10.0	9162257.	9162257.	9162257.	9162257.	9162257.
TOTAL CAPITALIZATION,$	.0	89841100.	89841100.	89841100.	89841100.	89841100.
COST OF ELEC-CAPITAL	25.0	4.09422	5.89568	7.36960	8.84352	10.23555
COST OF ELEC-FUEL	.0	19.34223	19.34223	19.34223	19.34223	19.34223
COST OF ELEC-OP & MAIN	.0	.59078	.59078	.59078	.59078	.59078
TOTAL COST OF ELEC	.0	24.02723	25.82869	27.30260	28.77652	30.15856

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU 1.50	2.60	4.00	2.08	3.12
TOTAL DIRECT COSTS,$	.0	58223480.	58223480.	58223480.	58223480.	58223480.
INDIRECT COST,$	51.0	5795993.	5795993.	5795993.	5795993.	5795993.
PROF & OWNER COSTS,$	8.0	4657878.	4657878.	4657878.	4657878.	4657878.
CONTINGENCY COST,$	6.0	3493409.	3493409.	3493409.	3493409.	3493409.
SUB TOTAL,$	.0	72170759.	72170759.	72170759.	72170759.	72170759.
ESCALATION COST,$	6.5	8508084.	8508084.	8508084.	8508084.	8508084.
INTREST DURING CONST,$	10.0	9162257.	9162257.	9162257.	9162257.	9162257.
TOTAL CAPITALIZATION,$	.0	89841100.	89841100.	89841100.	89841100.	89841100.
COST OF ELEC-CAPITAL	18.0	7.36960	7.36960	7.36960	7.36960	7.36960
COST OF ELEC-FUEL	.0	11.15898	19.34223	29.75727	15.47379	23.21067
COST OF ELEC-OP & MAIN	.0	.59078	.59078	.59078	.59078	.59078
TOTAL COST OF ELEC	.0	19.11935	27.30260	37.71765	23.43416	31.17105

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	58223480.	58223480.	58223480.	58223480.	58223480.
INDIRECT COST,$	51.0	5795993.	5795993.	5795993.	5795993.	5795993.
PROF & OWNER COSTS,$	8.0	4657878.	4657878.	4657878.	4657878.	4657878.
CONTINGENCY COST,$	6.0	3493409.	3493409.	3493409.	3493409.	3493409.
SUB TOTAL,$	.0	72170759.	72170759.	72170759.	72170759.	72170759.
ESCALATION COST,$	6.5	8508084.	8508084.	8508084.	8508084.	8508084.
INTREST DURING CONST,$	10.0	9162257.	9162257.	9162257.	9162257.	9162257.
TOTAL CAPITALIZATION,$	.0	89841100.	89841100.	89841100.	89841100.	89841100.
COST OF ELEC-CAPITAL	18.0	39.91866	10.64498	9.58048	7.36960	5.98780
COST OF ELEC-FUEL	.0	19.34223	19.34223	19.34223	19.34223	19.34223
COST OF ELEC-OP & MAIN	.0	1.84584	.75253	.70210	.59078	.51617
TOTAL COST OF ELEC	.0	61.10673	30.74013	29.62480	27.30260	25.84619

Curve 682432-A

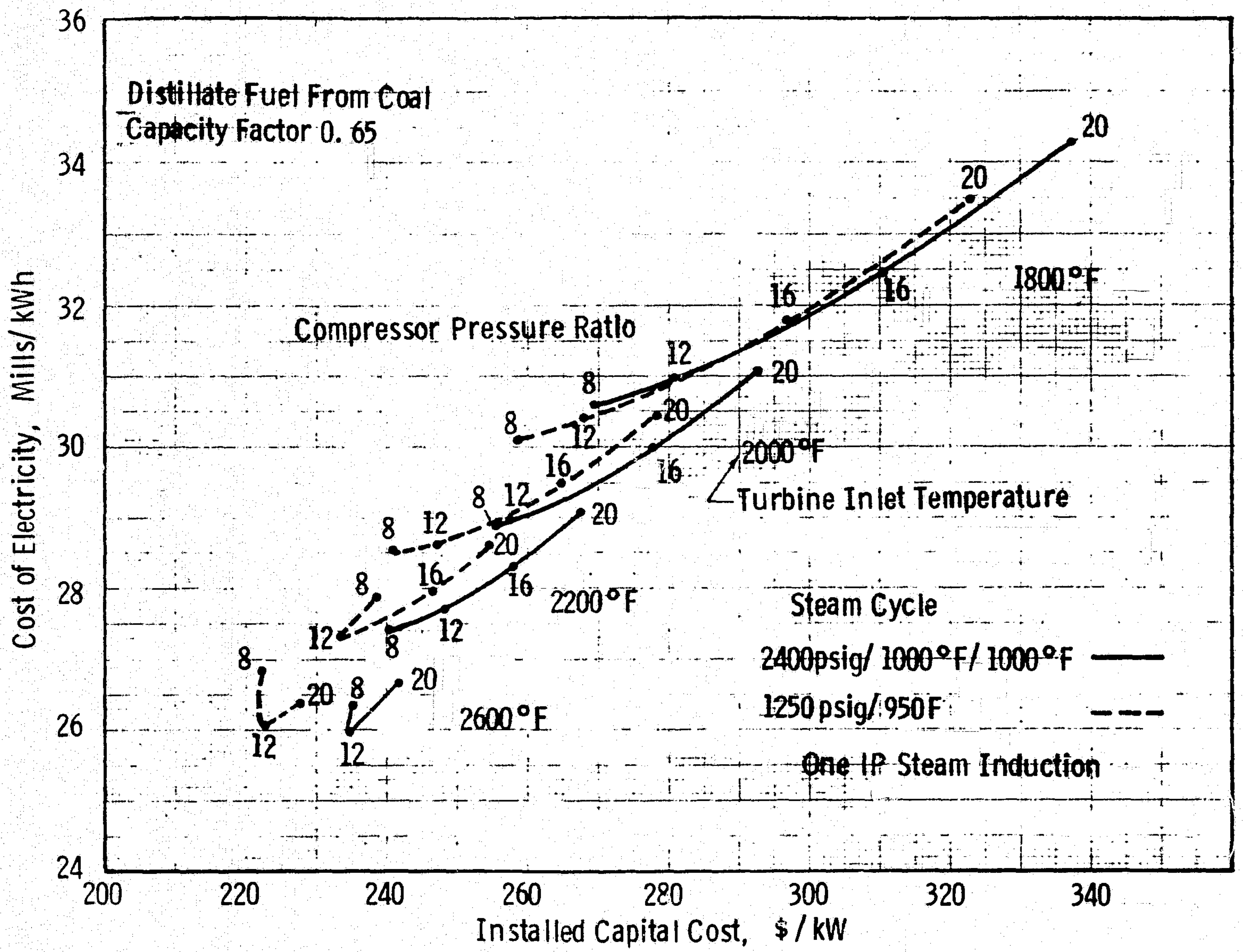

Fig. 6.32–Effect of gas turbine inlet temperature and compressor pressure ratio on cost of electricity

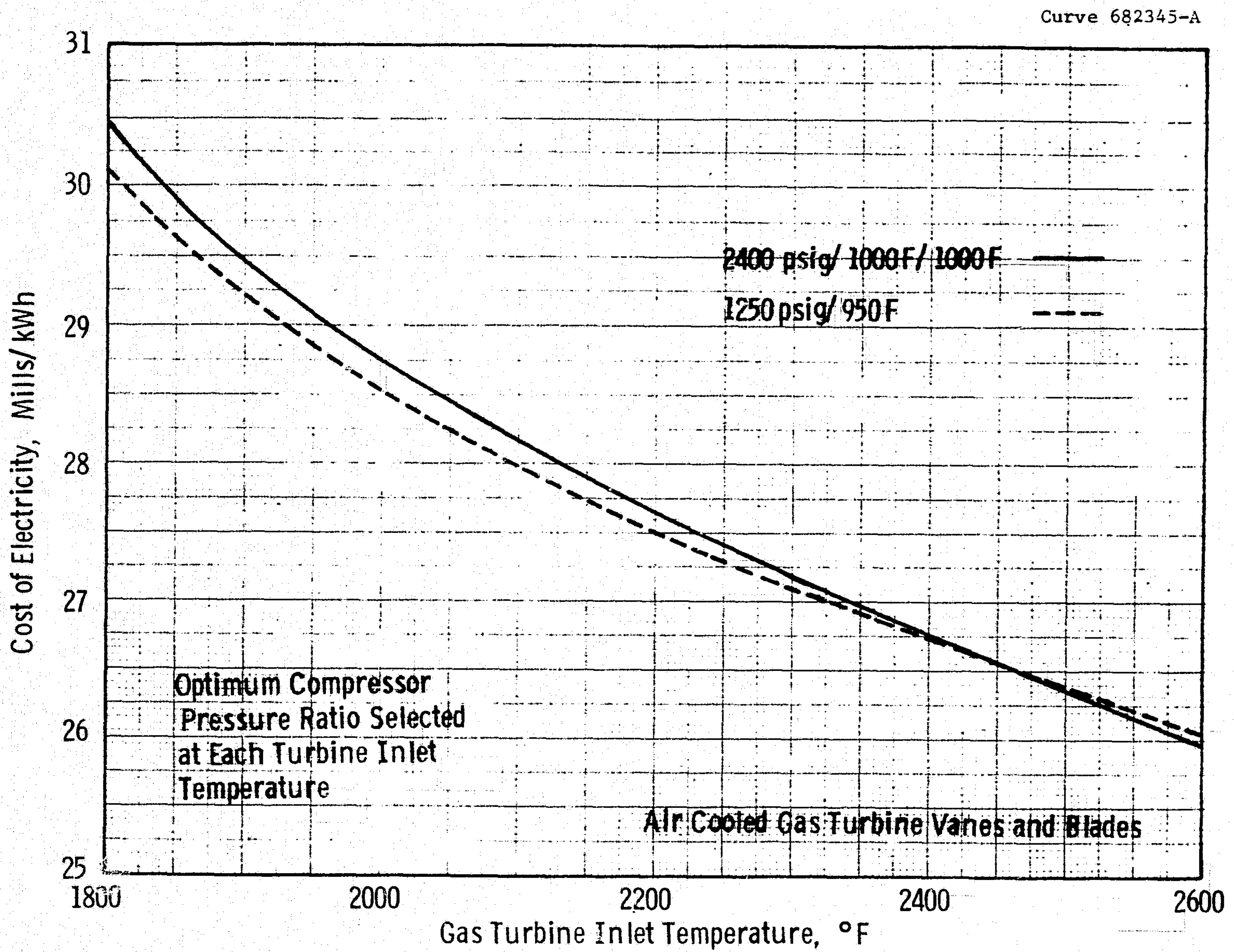

Fig. 6.33—Comparison of cost of electricity with reheat and nonreheat steam bottoming cycles

At the higher gas turbine inlet temperature, the reheat steam bottomed cycle enjoys a COE advantage. The comparison of COE obtained with both reheat and nonreheat steam cycles at various turbine inlet temperatures is examined in greater detail in Figure 6.33. At each turbine inlet temperature, the optimum value of the compressor pressure ratio has been selected for display in this curve. A crossover point of approximately 1644°K (2500°F) turbine inlet temperature is indicated at which the costs of electricity using the nonreheat and reheat steam bottoming cycles are equivalent.

Over the full range of gas turbine firing temperatures plotted on Figure 6.33 the greatest difference in COE between the cycles with reheat and nonreheat steam if 0.1 mills/MJ (0.35 mills/kWh) or 1.2% occurring at 1255°K (1800°F).

For all practical purposes, the COE from the cycles with reheat and nonreheat steam is essentially equal within the accuracy of the study.

The results of a comparison of COE obtained with various steam bottoming cycle arrangements are shown in Figure 6.34. This grouping compares reheat and nonreheat steam cycles with throttle pressures ranging from 8.618 to 16.547 MPa (1250 to 2400 psi) gauge and inductions at the reheater and crossover ducts. All these results were obtained using a gas turbine with 1478°K (2200°F) turbine inlet temperature, compressor pressure ratio of 12 to 1, and using air-cooled vanes and blades. With this set of gas turbine conditions, the 9.653 MPa (1450 psi) gauge steam cycle arrangements (both reheat and nonreheat) have a lower COE than the 12.411 to 16.547 MPa (1800 or 2400 psi) gauge cycles. At a higher gas turbine inlet temperature, the higher throttle pressure reheat steam cycle shows an advantage, as illustrated by the bar chart of Figure 6.35.

A detailed look at the effect of steam induction upon the COE has been performed in conjunction with the 16.547 MPa/811°K/811°K (2400 psig/1000°F/1000°F) steam bottomed combined cycle. The use of steam inductions at the reheat and crossover points was investigated individually and collectively. Results of these calculations are shown in

Curve 682428-A

2200 °F T_{it}, 12:1 Gas Turbine, Distillate Fuel From Coal, 0.65 Capacity Factor

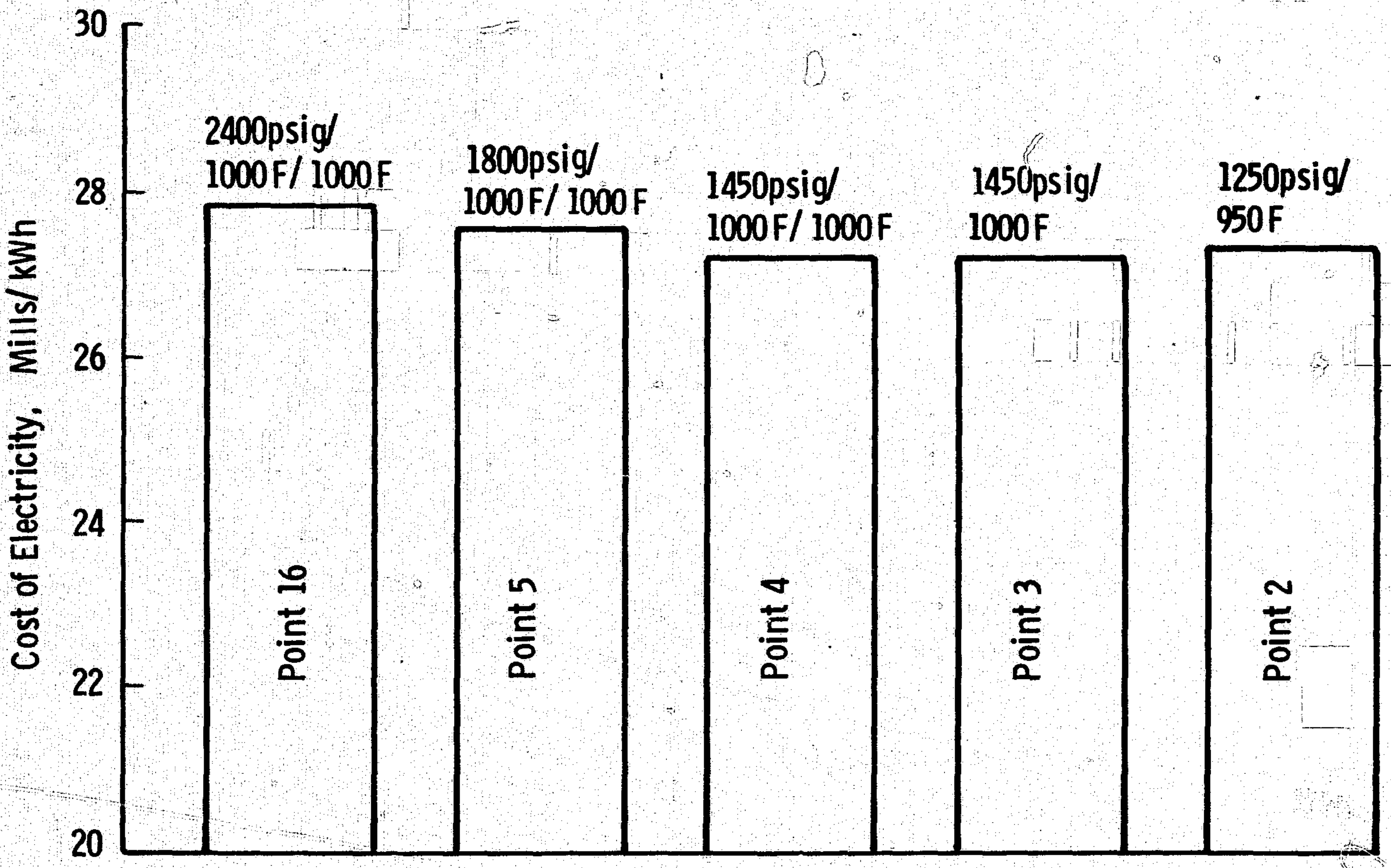

Fig. 6. 34 - Effect of steam conditions upon cost of electricity

Curve 682429-A

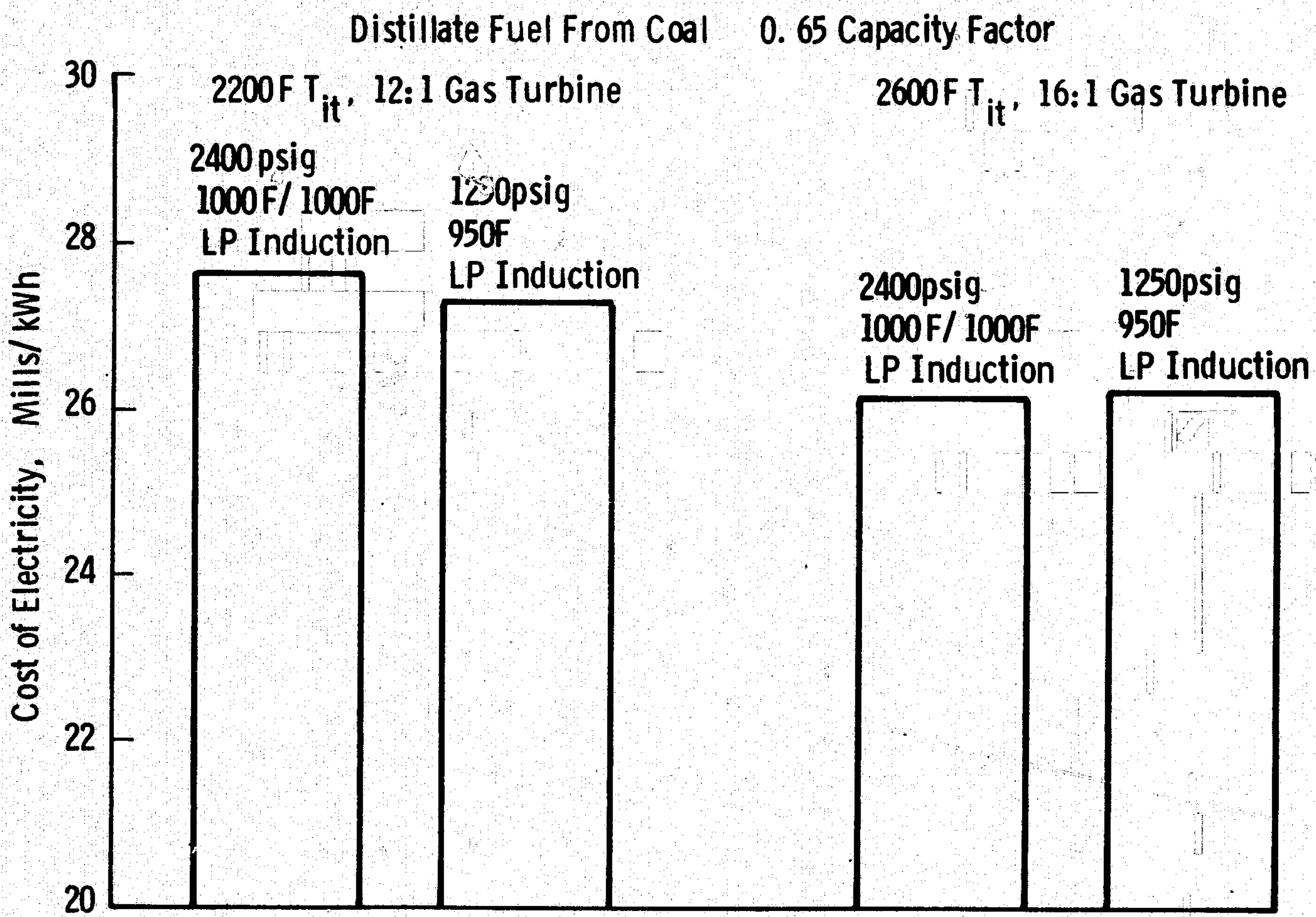

Fig. 6. 35 - Effect of turbine inlet temperature and steam conditions upon cost of electricity

Curve 682430-A

2400psig/ 1000°F/ 1000°F Steam Cycle; 2200°F T_{it}, 12:1 Gas Turbine
Distillate Fuel From Coal, 0. 65 Capacity Factor

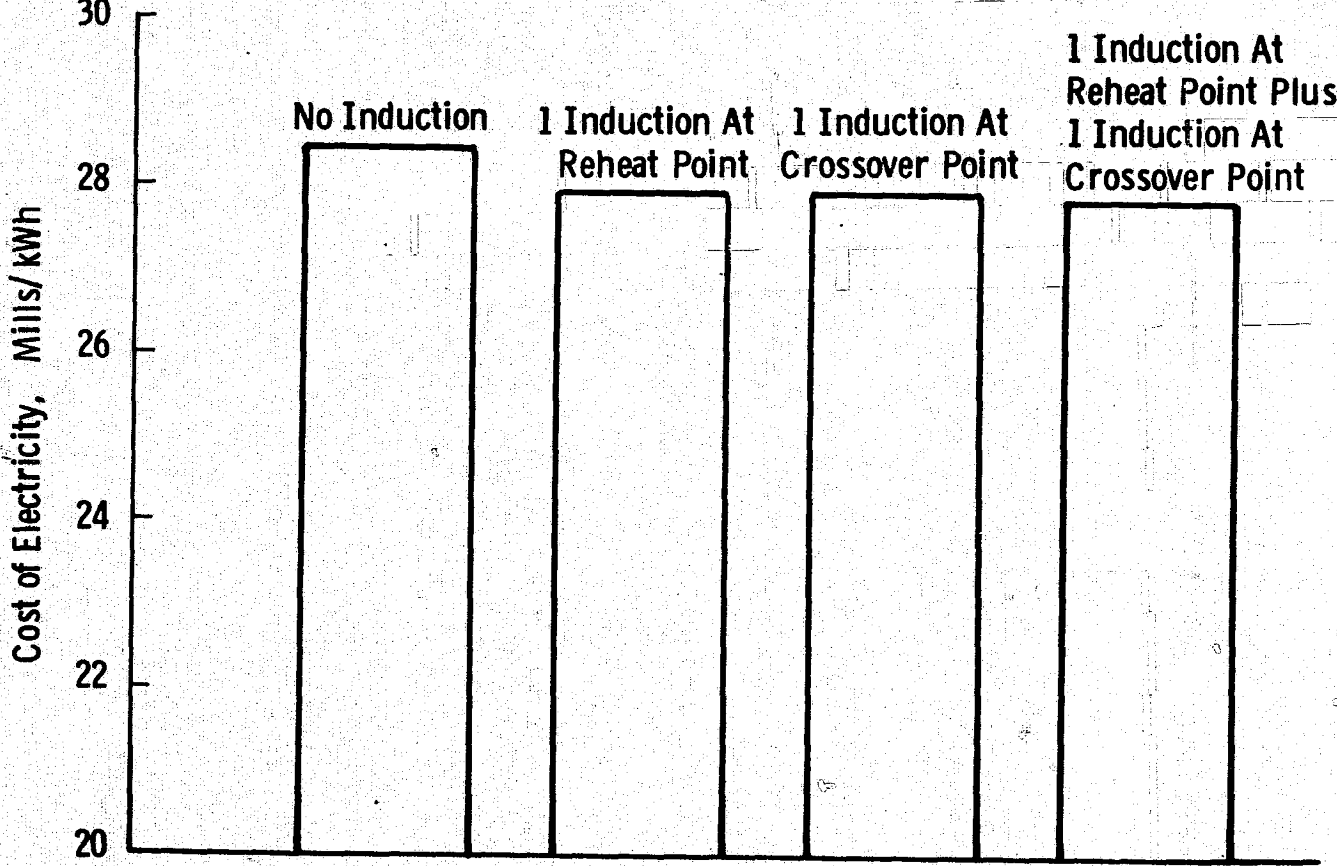

Fig. 6. 36 - Effect of induction on cost of electricity

Figure 6.36. Increasing the use of induction in these investigations resulted in a reduction in the COE. The greatest improvement was seen to come from the change from no induction to one induction, with little net difference observed between the use of a single induction at the reheat point or the crossover point. A smaller additional improvement in COE was observed when a second steam induction was added.

It should be appreciated that the differences in COE among the induction alternatives are quite small; and until confirmed by additional studies, the order of merit of the various systems should be regarded as just trends.

The use of supplementary firing of the heat recovery steam generator has been investigated in conjunction with both reheat and non-reheat steam bottoming cycles. In addition to the case of no supplementary firing, three levels of additional firing were used to increase the temperature of the gas turbine exhaust products entering the heat recovery boiler. The first level firing raised the exhaust products temperature to approximately 1033°K (1400°F). The second level achieved temperatures of approximately 1587°K (2400°F); and for the third level, a near stoichiometric temperature of approximately 2061°K (3250°F) was used. For both the reheat and nonreheat cases, the steam cycles were topped by a 1478°K (2200°F) turbine inlet temperature gas turbine at a 12-to-1 compressor pressure ratio, with air-cooled vanes and blades burning clean distillate fuel from coal. The results of the analysis, shown in Figure 6.37, indicate that additional supplementary firing increases the COE for both types of steam cycle, with a greater penalty observed in conjunction with the nonreheat arrangement.

Considerable attention has been focused upon the effect of the steam cycle heat rejection means upon COE. Three different systems were investigated, including the dry tower and wet tower systems, in which heat is rejected to the atmosphere; and the more conventional once-through systems, in which heat is rejected to a body of water as a heat sink. Again, both nonreheat and reheat steam bottoming cycles were investigated.

Curve 682427-A

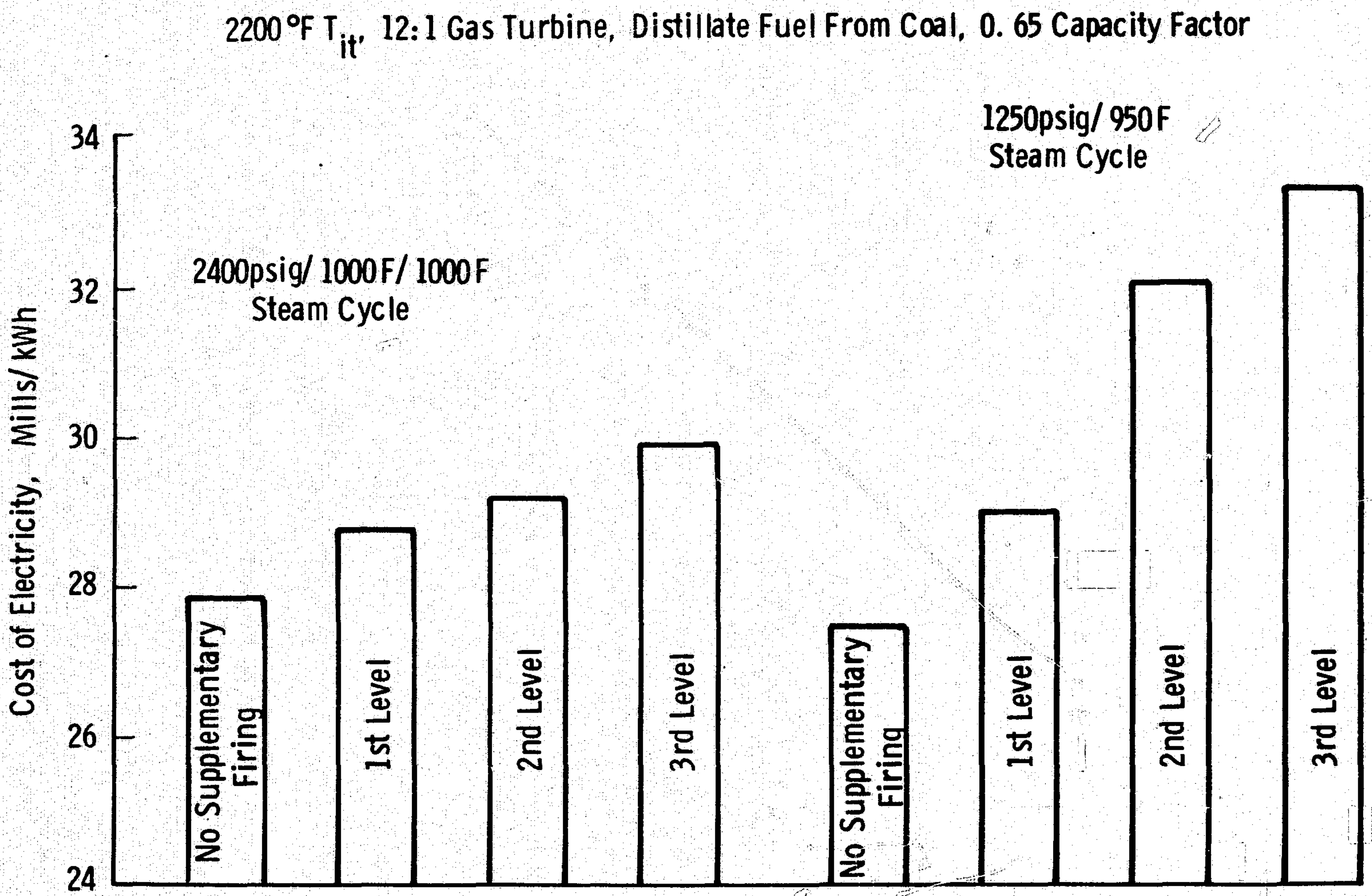

Fig. 6.37–Effect of HRSG supplementary firing on cost of electricity

The results shown in Figure 6.38 indicate that, compared with the once-through cooling, the COE with the dry tower and wet tower, are approximately 9 and 4% higher, respectively.

The effect of fuel preparation on the COE has been investigated as a comparison between a combined-cycle plant with an integrated gasification system and a similar combined cycle firing distillate from coal. Both cycles utilize a 1478°K (2200°F) turbine inlet temperature gas turbine at a 12-to-1 pressure ratio with air-cooled vanes and blades. The COE results have been plotted as a function of capacity factor for each arrangement in Figure 6.39. The results show that for capacity factors greater than approximately 0.45, the integrated gasification system is economically superior under the assumption of a liquid fuel price of $2.46/GJ ($2.60/10^6 Btu). At an 80% capacity factor, the integrated gasification system results in a COE approximately 30% lower than the counterpart combined cycle burning distillate from coal.

For each parametric point the natural resource requirements have been estimated. These consist of coal, sorbent (for gasification systems), water for heat rejection, gasifier process steam, condensate makeup, waste slurry handling, and scrubber waste, as well as land usage for the main plant, disposal, and access railroad. The results of these calculations for all parametric points investigated are summarized in Table 6.12.

6.7 Conclusions and Recommendations

6.7.1 Conclusions

The gas-steam combined-cycle system, in comparison with other ECAS Task I energy conversion systems, is attractive for intermediate and higher capacity factor operation.

Several parameters affect conclusions regarding optimization of the combined-cycle system with respect to efficiency and COE. The more important of these include: gas turbine inlet temperature and compressor

Curve 682433-A

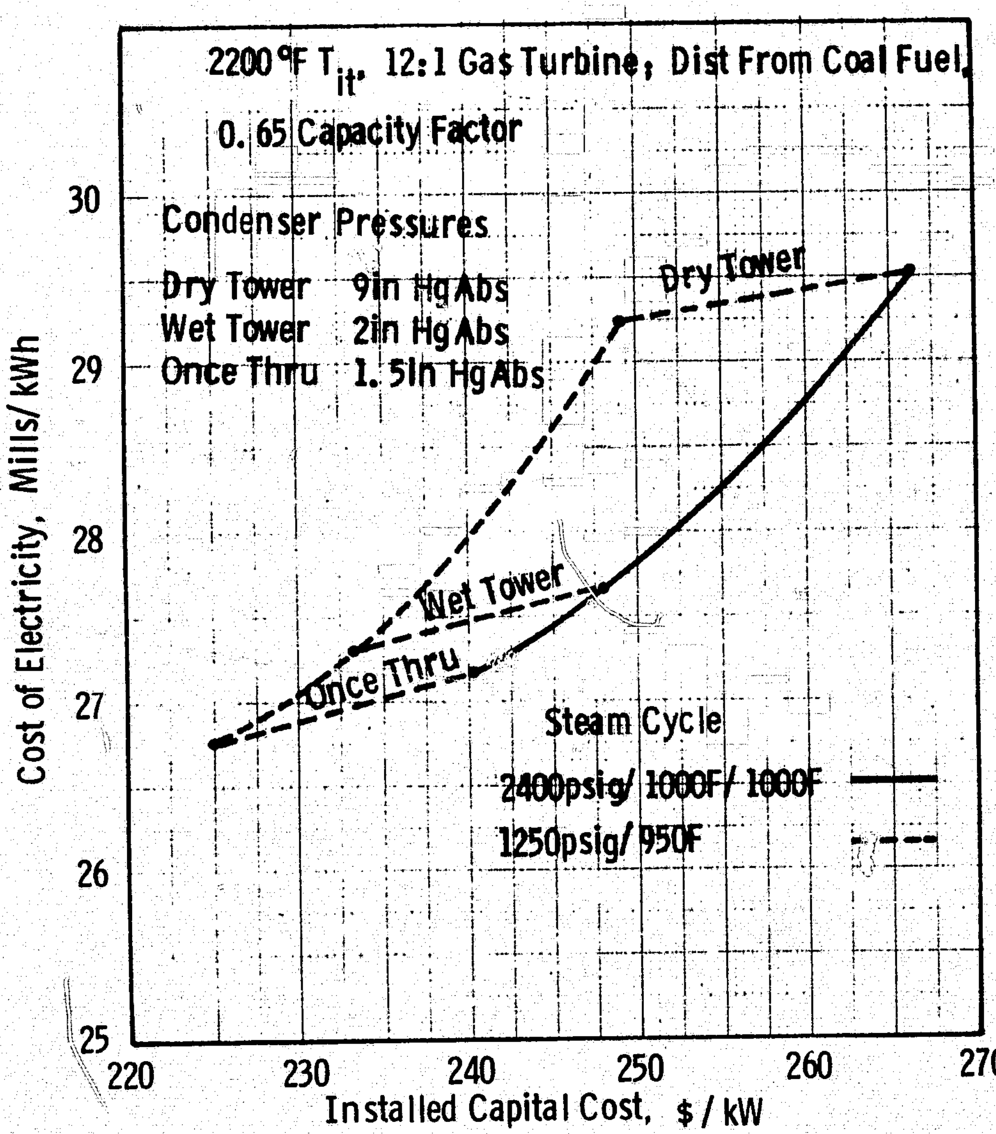

Fig. 6.38—Effect of steam cycle heat rejection method on cost of electricity

Curve 682343-A

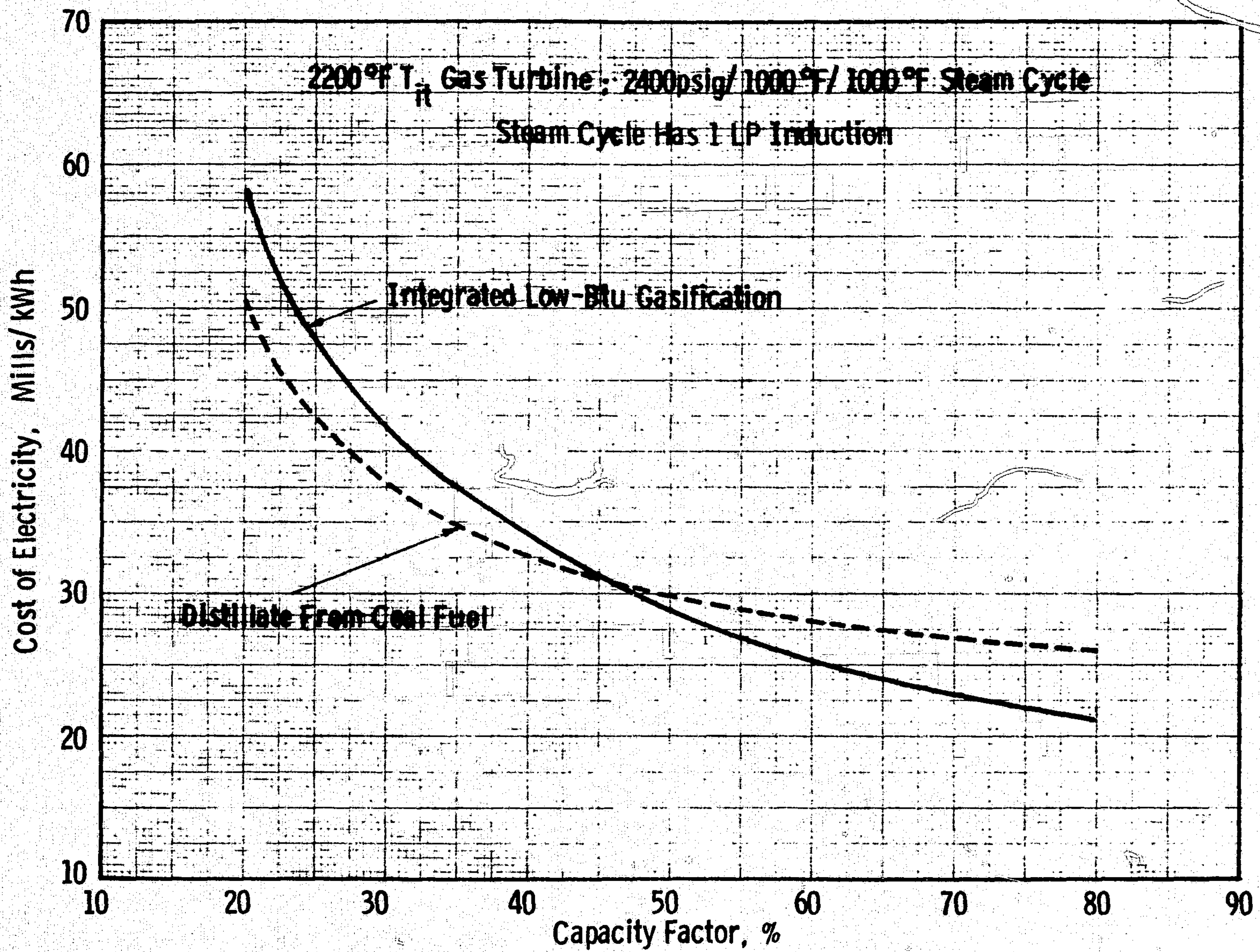

Fig.6. 39— Comparison of coal gasification and distillate fuel effects on combined cycle cost of electricity

Table 6.12 COMBINED GAS-STEAM TURBINE CYCLE NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
COAL, LB/KW-HR	.74313	1.35739	1.35056	1.32321	1.32431	not calculated	1.34805	1.36591
SORBANT OR SEED, LB/KW-HR	.39319	.00000	.00000	.00000	.00000		.00000	.00000
TOTAL WATER, GAL/KW-HR	.537	.487	.485	.455	.452		.447	.464
COOLING WATER	.425	.484	.482	.453	.448		.444	.460
GASIFIER PROCESS H2O	.04280	.00000	.00000	.00000	.00000		.00000	.00000
CONDENSATE MAKE UP	.00330	.00334	.00342	.00352	.00354		.00343	.00334
WASTE HANDLING SLURRY	.0514	.0000	.0000	.0000	.0000		.0000	.0000
SCRUBBER WASTE WATER	.04459	.00000	.00000	.00000	.00000		.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000		.00000	.00000
TOTAL LAND ACRES/100MWE	98.82	36.56	35.18	32.48	32.41		32.90	33.27
MAIN PLANT	15.45	12.97	12.88	11.85	11.84		11.97	12.05
DISPOSAL LAND	62.47	.00	.00	.00	.00		.00	.00
LAND FOR ACCESS RR	20.88	23.59	22.30	20.62	20.57		20.93	21.21
PARAMETRIC POINT	9	10	11	12	13	14	15	16
COAL, LB/KW-HR	1.35616	1.36120	1.37675	1.35272	1.40589	1.34417	1.45197	1.32043
SORBANT OR SEED, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.455	.459	.461	.454	.343	.003	.003	.451
COOLING WATER	.452	.455	.457	.451	.340	.000	.000	.447
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP	.00335	.00341	.00334	.00341	.00314	.00340	.00299	.00356
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	33.07	33.17	33.29	33.00	29.25	11.92	70.15	32.33
MAIN PLANT	12.01	12.04	12.07	11.99	12.27	11.92	12.54	11.82
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	21.06	21.13	21.22	21.00	16.98	.00	57.61	20.51
PARAMETRIC POINT	17	18	19	20	21	22	23	24
COAL, LB/KW-HR	1.35354	1.43239	1.47720	1.35342	1.37245	1.35380	1.37040	1.36946
SORBANT OR SEED, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	1.025	.662	.733	.480	.491	.484	.490	.488
COOLING WATER	1.020	.655	.726	.477	.488	.481	.486	.485
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP	.00491	.00663	.00745	.00338	.00332	.00331	.00337	.00338
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	58.12	42.18	42.86	36.39	36.68	36.48	36.63	36.61
MAIN PLANT	12.28	11.98	10.04	12.93	13.00	12.95	12.99	12.99
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	45.84	30.20	32.82	23.46	23.68	23.53	23.64	23.63
PARAMETRIC POINT	25	26	27	28	29	30	31	32
COAL, LB/KW-HR	1.36474	1.38409	1.35001	1.46957	1.37254	1.41153	1.58353	1.66232
SORBANT OR SEED, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.486	.448	.003	.003	.498	.576	.820	.931
COOLING WATER	.482	.445	.000	.003	.494	.571	.813	.924
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP	.00335	.00326	.00337	.00291	.00332	.00440	.00631	.00718
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	36.50	36.36	12.85	74.45	36.69	40.47	52.42	56.71
MAIN PLANT	12.96	13.07	12.85	13.58	13.01	12.83	16.43	13.91
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	23.54	23.89	.00	60.88	23.68	27.64	35.98	42.79

Table 6.12 COMBINED GAS-STEAM TURBINE CYCLE NATURAL RESOURCE REQUIREMENTS

Continued

PARAMETRIC POINT	33	34	35	36	37	38	39	40
COAL, LB/KW-HR	1.51247	1.51577	1.55751	1.52595	1.42502	1.42770	1.45594	1.49332
SORBANT OR SEED, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.559	.538	.532	.539	.507	.495	.492	.495
COOLING WATER	.554	.535	.529	.537	.503	.493	.489	.492
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00360	.00292	.00252	.00229	.00387	.00316	.00275	.00250
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	39.28	39.55	38.89	44.55	35.76	35.84	35.84	39.08
MAIN PLANT	14.23	15.23	15.37	17.72	12.69	13.39	14.20	15.1[illegible]
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	24.93	24.32	23.52	26.83	23.07	22.44	21.64	23.99

PARAMETRIC POINT	41	42	43	44	45	46	47	48
COAL, LB/KW-HR	1.36114	1.35853	1.38291	1.41530	1.31662	1.30491	1.32484	1.35394
SORBANT OR SEED, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.472	.457	.457	.460	.449	.427	.423	.429
COOLING WATER	.468	.454	.454	.457	.445	.424	.420	.42[illegible]
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00409	.00338	.00294	.00253	.00424	.00357	.00313	.00285
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	33.24	33.13	33.05	35.54	31.47	31.08	30.84	32.99
MAIN PLANT	11.50	12.03	12.65	13.31	10.59	10.97	11.46	11.99
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	21.75	21.10	20.40	22.22	20.87	20.11	19.40	21.00

PARAMETRIC POINT	49	50	51	52	53	54	55	56
COAL, LB/KW-HR	1.28577	1.26521	1.27896	1.30225	1.51104	1.50613	1.54036	1.60189
SORBANT OR SEED, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.442	.436	.398	.399	.574	.535	.518	.516
COOLING WATER	.437	.403	.395	.395	.571	.533	.515	.514
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00432	.00372	.00331	.00302	.00361	.00297	.00261	.00241
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	30.34	29.61	27.35	29.02	46.58	43.93	40.70	45.26
MAIN PLANT	9.92	10.15	10.53	10.95	15.36	15.31	17.47	18.86
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	20.42	19.45	16.81	18.07	31.22	28.62	23.24	26.41

PARAMETRIC POINT	57	58	59	60	61	62	63	64
COAL, LB/KW-HR	1.44008	1.42565	1.44908	1.48707	1.39527	1.38192	1.41067	1.36404
SORBANT OR SEED, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.547	.510	.494	.487	.531	.470	.465	.521
COOLING WATER	.543	.506	.491	.485	.527	.467	.462	.517
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00341	.00317	.00278	.00255	.00395	.00295	.00271	.00405
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	39.64	36.80	39.85	43.34	39.30	39.03	35.42	35.22
MAIN PLANT	13.73	14.39	15.22	16.15	12.55	13.[illegible]	14.28	11.63
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	25.91	22.42	24.63	27.19	26.75	25.47	22.14	23.59

Table 6.12 COMBINED GAS-STEAM TURBINE CYCLE NATURAL RESOURCE REQUIREMENTS
Continued

PARAMETRIC POINT	65	66	67	68	69	70	71	72
COAL, LB/KW-HR	1.32973	1.33257	1.35334	1.35735	1.30211	1.30359	1.31227	1.32437
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.474	.451	.443	.547	.465	.442	.429	.451
COOLING WATER	.471	.448	.440	.543	.462	.439	.425	.447
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00346	.00310	.00285	.00408	.00356	.00320	.00297	.00411
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	36.52	34.14	36.22	39.54	32.92	34.40	32.07	30.63
MAIN PLANT	11.33	12.36	12.89	10.93	11.10	11.44	11.83	10.86
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	24.53	21.78	23.33	28.55	21.82	22.95	20.24	19.77

PARAMETRIC POINT	73	74	75	76	77	78	79	80
COAL, LB/KW-HR	1.31362	1.32824	1.34737	1.30260	1.28666	1.29323	1.30596	Not calculated
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	
TOTAL WATER, GAL/KW-HR	.431	.430	.431	.439	.416	.411	.413	
COOLING WATER	.428	.427	.429	.435	.413	.408	.410	
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	
CONDENSATE MAKE UP ,	.00341	.00296	.00259	.00413	.00344	.00293	.00269	
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	
TOTAL LAND ACRES/100MWE	30.37	32.45	32.15	30.86	30.65	30.47	30.10	
MAIN PLANT	11.31	11.85	12.40	10.45	10.86	11.34	11.83	
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	
LAND FOR ACCESS RR	19.06	20.60	19.76	20.41	19.79	19.14	18.27	

PARAMETRIC POINT	81	82	83	84	85	86	87	88
COAL, LB/KW-HR				1.35347				
SORBANT OR SEED,LB/KW-HR				.00000				
TOTAL WATER, GAL/KW-HR				.453				
COOLING WATER				.449				
GASIFIER PROCESS H2O				.00000				
CONDENSATE MAKE UP ,				.00333				
WASTE HANDLING SLURRY				.0000				
SCRUBBER WASTE WATER		Not calculated		.00000				
NOX SUPPRESSION				.00000				
TOTAL LAND ACRES/100MWE				28.48				
MAIN PLANT				8.07				
DISPOSAL LAND				.00				
LAND FOR ACCESS RR				20.41				

PARAMETRIC POINT	89	90	91	92	93	94	95	96
COAL, LB/KW-HR	1.34464	1.34355	1.41372	.00000	.00000	.00000	.00000	.00000
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.426	.472	.367	.000	.000	.000	.000	.000
COOLING WATER	.423	.458	.353	.000	.000	.000	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00344	.00345	.00311	.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	37.11	37.08	33.77	.00	.00	.00	.00	.00
MAIN PLANT	16.23	16.22	16.71	.00	.00	.00	.00	.00
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	20.88	20.86	17.07	.00	.00	.00	.00	.00

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pressure ratio, steam cycle nominal conditions, the use of steam induction, supplementary heat recovery steam generator firing, heat rejection means, and the use of integrated low-Btu coal gasifications.

As gas turbine inlet temperatures are increased, the resultant thermodynamic efficiencies are increased and the COE decreases. Further, from the viewpoint of both efficiency and COE, the optimum gas turbine compressor pressure ratios generally increase with higher turbine inlet temperatures. For the range of turbine inlet temperatures investigated, 1255 to 1700°K (1800 to 2600°F), it was determined that for best combined-cycle efficiency, and using convection impingement air-cooled gas turbine blading, the optimum compressor pressure ratio lies in the range of 10 to 16.

The differences in COE obtained with varying steam cycle configurations and nominal throttle steam conditions are small and in many cases less than the uncertainties inherent in such a study. It was observed, however, that at the lower gas turbine inlet temperatures, the lower throttle pressure nonreheat and reheat steam cycles yielded a lower COE. For the lower throttle pressure reheat steam bottoming plants, for example 9.997 MPa/811°K/811°K (1450 psig/1000°F/1000°F), no parametric optimizations were performed. Further investigation of these cycles and comparison with the 8.618 MPa/783°K (1250 psig/950°F) bottoming cycle would be quite useful. At the higher gas turbine inlet temperatures, the higher pressure reheat steam cycles showed the lower COE with the gas turbine inlet temperature at which the two types become equal being approximately 1589°K (2400°F).

The use of steam induction generally results in a high cycle efficiency and a lower COE. In the case where multiple induction was assumed, in conjunction with a reheat steam cycle, the use of the first induction is most significant in lowering the overall COE.

The use of supplementary firing in the heat recovery steam generator results in a higher COE than for an unfired steam generator arrangement. The 16.547 MPa/811°K/811°K (2400 psig/1000°F/1000°F) reheat steam cycle arrangement is less sensitive to an increased COE with supplementary firing than the 8.618 MPa/783°K (1250 psig/950°F) nonreheat steam cycle.

Heat rejection to the atmosphere by means of wet and dry cooling towers results in a higher COE than does the use of a once-through cooling system. The most significant increase occurs in conjunction with the use of dry cooling towers; the COE is nearly 9% higher with this arrangement than with the once-through method.

The use of integrated low-Btu coal gasification offers superior COE performance for base-load duty, as compared with a coal-derived distillate fueled combined cycle. Based on an 80% capacity factor, and using coal-derived distillate fuel at \$2.46/GJ (\$2.60/10^6 Btu) compared with Illinois No. 6 bituminous coal at \$0.806/GJ (\$0.85/10^6 Btu), the combined cycle with the integrated low-Btu gasification system can generate electricity at a nearly 30% lower cost than the corresponding plant burning distillate. At capacity factors down to approximately 0.45, the combined-cycle plant with the integrated gasification system gives the lowest COE.

6.7.2 Recommendations

It is recommended that a continued conceptual design effort be applied in the following areas in order to achieve maximum benefit from the gas-steam combined cycle.

6.7.2.1 Induction Steam Turbine Generator

Induction steam turbines have been built and successfully operated for some time in smaller sizes. Comparable experience in large power generation size units is minimal. Further design investigations into the configurations and operational requirements (particularly with regard to control and turbine protection) of the induction steam turbine will be required.

6.7.2.2 Gas Turbine Inlet Temperature

Gas turbines currently operate at approximately 1366°K (2000°F) turbine inlet temperature in base-load commercial power generation service. Analysis shows continued improvement in the COE with increasing turbine inlet temperatures. A continued design and development effort with advanced gas turbine blading materials and cooling techniques will be required in order to realize the benefits concommitant with higher turbine inlet temperatures. The conceptual design of an advanced combined-cycle plant with an integrated gasification system based on high-temperature gas turbine technology should be continued.

6.7.2.3 Integrated Coal Gasification System

Satisfactory service with an integrated combined-cycle gasification system has not been demonstrated. Further, existing commercially available coal gasifiers have not been designed for integrated combined-cycle operation. Therefore, continued development of the integrated coal gasification subsystem is needed. It is particularly necessary that development of efficient gas cleanup methods be emphasized to ensure compatibility with gas turbine engine requirements.

Just as a continuing, vigorous effort toward developing higher turbine inlet temperatures is essential to realize continued benefits from gas turbine technology advances, the fact should not be overlooked that today's combined cycles operating at turbine inlet temperatures of about 1366°K (2000°F), continuous duty, compare most favorably in terms of thermodynamic efficiency with conventional power generating modes. In order to bring to fruition as quickly as possible the benefits of the combined-cycle plant with an integrated coal gasification system, attention should be directed to coupling current coal gasification technology with more moderate advances in gas turbine technology than those indicated by the arbitrary upper turbine inlet temperature bounds of this parametric study. A conceptual design effort aimed at early implementation of an integrated combined-cycle plant with turbine inlet temperatures in the 1478 to 1533°K (2200 to 2300°F) range should be commenced as well.

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