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ENERGY CONVERSION ALTERNATIVES STUDY
-ECAS-
WESTINGHOUSE PHASE I FINAL REPORT
Volume XI — ADVANCED STEAM SYSTEMS

by
R.W. Wolfe

WESTINGHOUSE ELECTRIC CORPORATION RESEARCH LABORATORIES

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16. Abstract

A parametric analysis was made of three types of advanced steam power plants to make a comparison of the cost of electricity produced by them over a wide range of primary performance variables. Increasing the temperature and pressure of the steam above current industry levels resulted in increased energy costs because the cost of capital increased more than the fuel cost decreased. While the three plant types produced comparable energy cost levels, the pressurized fluidized bed boiler plant produced the lowest energy cost by the small margin of 0.69 mills/MJ (2.5 mills/kWh). It is recommended that this plant be designed in greater detail to determine its cost and performance more accurately than was possible in a broad parametric study and to ascertain problem areas which will require development effort.

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SUMMARY

The objective of this study is to determine, by means of parametric analyses, the performance, economics, natural resource requirements, and environmental intrusion of coal burning advanced steam power generation systems. This analysis is conducted for three types of advanced steam systems: atmospheric furnace systems; pressurized boiler-gasifier systems; pressurized fluidized bed boiler systems.

The primary parameters which are investigated were steam temperature 811 to 1033°K (1000°F to 1400°F), steam pressure 16.547 to 34.474 MPa (2400 psi to 5000 psi), gas turbine temperature 1144 to 1644°K (1600°F to 2500°F) and gas turbine pressure ratio (8:1 to 25:1). Other parameters which were investigated are condenser pressure (as a function of heat rejection method), power level, excess combustion air, coal type, and number of steam reheats.

The cost and performance was calculated for plants which included all the equipment necessary to meet the proscribed emissions restraints. For the atmospheric furnace system, this included a precipitator and a sulfur dioxide scrubber for the stack gas. For the pressurized boiler-gasifier system, the sulfur dioxide removal is accomplished by a reaction with dolomite in the pressurized fluidized bed coal gasifier. Particulate removal is accomplished by high temperature cyclone type separators. The cleanup method for the pressurized fluidized bed boiler system is essentially the same as the gasifier system except that the products of combustion rather than the fuel gas are cleaned.

The cost and performance analysis showed that increasing either the throttle or reheat steam temperature to 811 or 1033°K (1200 or 1400°F) results in an increase in cost of electricity because

the increase due to higher capital cost substantially exceeds the decrease due to lower fuel costs.

The minimum calculated cost of electricity for each of the systems is as follows: atmospheric furnace systems 6.94 mills/MJ (25 mills/kwh); pressurized boiler-gasifier systems 7.5 mills/MJ (27 mills/kwh); pressurized fluidized bed boiler system 6.11 mills/MJ (22 mills/kwh).

While these energy cost differences are not large, they are certainly significant and it is on the basis of these differences that the pressurized fluidized bed boiler system was recommended for further study in Task II.

12. ADVANCED STEAM SYSTEMS

12.1 State of the Art

As an overview of the state of the art with regard to performance, Figure 12.1 shows the national average heat rates* for fossil fuel steam-electric plants. As can be seen, the heat rate has clearly leveled off at 10,500 Btu/kWh. For 1971, the average heat rate of the best plants was 8915 Btu/kWh, with a negligible difference between the 24.132 MPa/811°K/811°K (3500 psi/1000°F/1000°F) plants and the 16.547 MPa/811°K/811°K (2400 psi/1000°F/1000°F) plants.

Further, if we look to the immediate future we cannot expect a change in these figures. Of the coal-fired units currently being built or on order, 35 are 12.411 MPa/811°K/811°K (1800 psi/1000°F/1000°F) units, 153 are 16.547 MPa/811°K/811°K (2400 psi/1000°F/1000°F), and 53 are 24.132 MPa/811°K/811°K (3500 psi/1000°F/1000°F). There are no coal-fired plants on order with steam conditions more advanced than these.

This does not mean, however, that these are the most advanced steam conditions existing in a currently operating steam power plant. One of the most famous steam power plants in the world, Eddystone I, went into service in 1960. This plant was designed for steam conditions of 34.474 MPa/922°K/839°K/839°K (5000 psi/1200°F/1050°F/1050°F) and was first run at these temperatures in 1961. Further, this plant is being run today as a base-load plant with a turbine inlet temperature of 886°K (1135°F) and a pressure close to 34.474 MPa (5000 psi). The plant had an original design value heat rate of 8230 Btu/kWh and an actual annual average heat rate of 8534 Btu/kWh for the year 1963 (Reference 12.1).

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* Heat rate is the common dimensional term used in the industry to specify thermodynamic performance. Its units are Btu/kWh. Its inverse, multiplied by an appropriate constant, gives the efficiency.

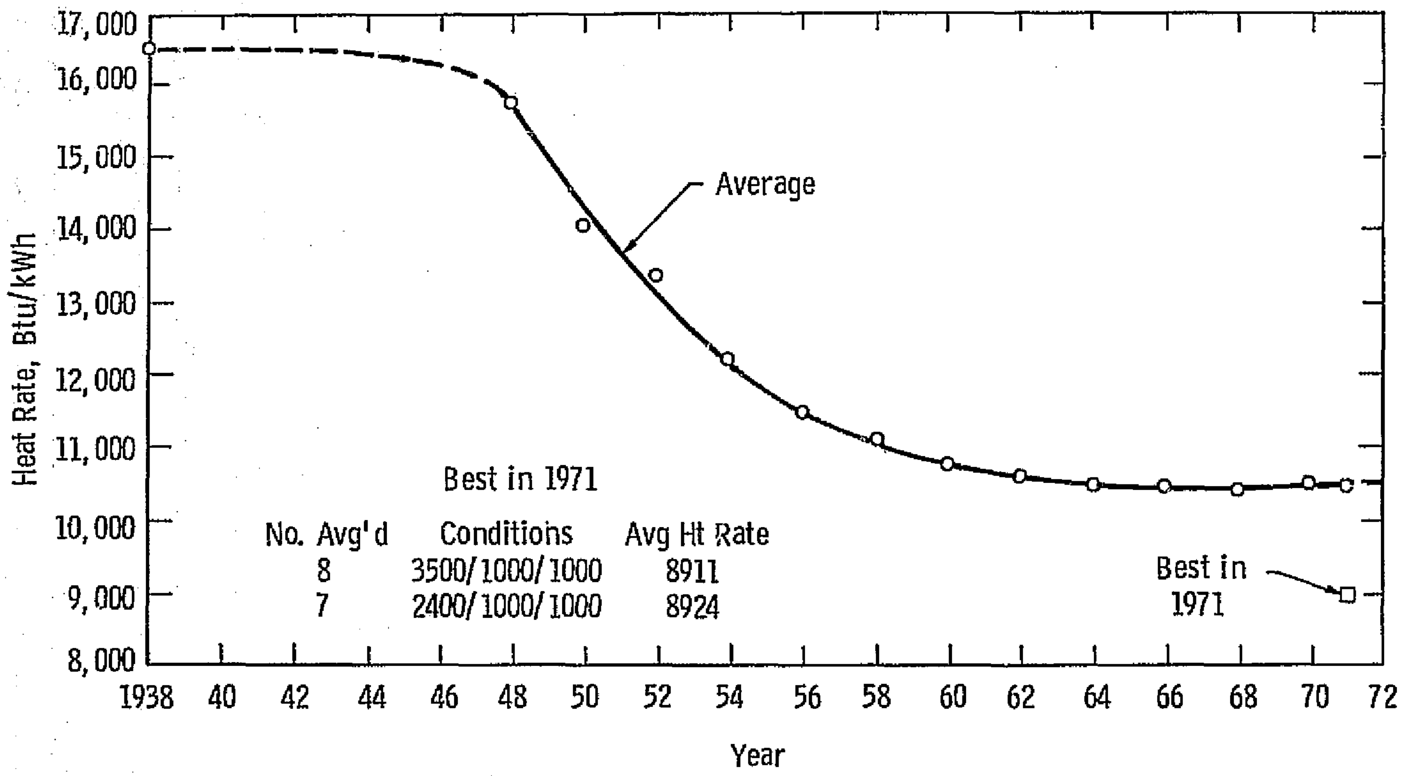

Fig. 12.1—National average heat rates for fossil fueled steam-electric plants

A great deal of information obtained from the experience of designing, constructing, and operating this plant is germane to the development of future steam plants with the same or greater steam temperatures and pressures. For instance, the turbine suffers in performance slightly in the high-pressure end because the steam flow rate corresponding to the design power level of 325 MWe is too low, resulting in parasitic losses being too high a percentage of the output.

The turbine control and stop valves have had cracking problems due to low cycle fatigue. Redesigned valves have been offered by Westinghouse to circumvent this problem, but currently the utility is avoiding the problem (and therefore the replacement cost) by operating below 922°K (1200°F). Whatever the design, however, the life is dependent upon minimizing the frequency of thermal stress cycles. This means that the plant should be run strictly as a base-load plant with minimal load following operation.

Design improvements have been made in junction headers to reduce cracking, but the basic tube life of the superheaters and reheaters is affected most directly by fire-side corrosion caused primarily by the combination of high temperature and the chemical action of the coal ash. A reduction in the maximum steam temperature to 886°K (1135°F) has led to a substantial reduction in the amount of boiler tube replacement.

While the design value of superheat temperature was increased significantly for the Eddystone plant, the reheat temperatures were at normal levels so that the turbines below the superpressure unit did not require significant departure from state-of-the-art design. This will not be the case, however, for reheat temperature levels of 922 and 1033°K (1200 and 1400°F). In this case there will be major design problems in the HP, IP, and LP turbines, in addition to those encountered in the heat exchangers and piping. For instance, facilities do not exist which are capable of forging rotors of the size required in higher-alloy materials, and the development of such facilities would require major financial commitments. Alternatively, the design and development of a disk-curvic

TABLE 12.1—ECONOMIC COMPARISON 600 MWe PLANTS[a]
(3% Sulfur Coal)

	Pressurized Fluid Bed Boiler Combined Cycle Once-through Dolomite Sulfur Removal System	Conventional Coal-Fired Plant Wellman-Lord Sulfur Removal System	Conventional Coal-Fired Plant w/o Sulfur Removal System
Plant Capital Cost, $/kw	269	350	306
Energy Costs, mills/kWh			
Fixed charges	6.55	8.60	7.48
O&M	0.71	1.21	0.67
Fuel	4.09	4.55	4.11
	0.75 (dolomite)		
TOTAL	12.10	14.36	12.26

[a] 15%/year
70% capacity factor
No sulfur credit
Coal @ 45¢/10^6 Btu
Methane @ 80¢/ 10^6 Btu (Wellman-Lord)
Dolomite at $ 10/ ton (purchase plus disposal)
1975 operation of fluid bed boiler plant; 1976 operation of conventional plant.

clutch-through bolt approach would constitute a major program whose technical and economic viability would have to be carefully evaluated.

There is no existing unit comparable to the Eddystone unit for pressurized boiler power plants. Various studies and proposals have been made (for example, see Reference 12.2), but the basic impediment to their development is the difficulty of using coal as the energy source. The compactness and high heat transfer rates which result in their economic attractiveness make them very vulnerable to the deleterious effects of deposition and corrosion caused by the use of coal.

Currently, there are two primary approaches to accomplish the successful application of coal to pressurized boilers. The simplest, from the viewpoint of the boiler, is the use of a clean gaseous fuel which has been derived from a close-coupled coal gasifier unit. The other is a fluidized bed type of boiler into which raw coal is fed, the treatment of which is an integral function of the system. The thermodynamic cycle characteristics of these two types are very similar. The kinds of problems they present to the development engineer are quite different, however.

The pressurized fluidized bed boiler concept has been studied in considerable detail by Westinghouse for the Environmental Protection Agency (EPA) and has been reported (Reference 12.3). These studies have shown that a lower energy cost is achieved by the pressurized system than by the atmospheric system. (The cost figures which have been published are shown in Table 12.1.)

The key uncertainty is whether the projected equipment and sorbent materials, with their associated costs, will provide the required degree of mechanical and chemical cleanliness to result in satisfactory life of components such as the gas turbine, steam superheater, and reheater. A number of problem areas have been identified in the EPA report. Table 12.2, taken from the report, is a concise description of these problems and potential solutions.

Table 12.2 - Problem Areas

	Proposed Design	Primary Backup	Alternatives
Particulate Removal[1]	Cyclones and Aerodyne-type dust collectors	• Provision for third stage • Reduce gas velocity • Reduce fines content of solids feed • Alternative system: granular bed filter	• Cool gas and reheat prior to gas turbine • Modify turbine • Drop back on gas-turbine operating conditions
Sulfur Dioxide Control	Dolomite, in bed; 1.2 to 2 Ca/S	• May have to increase use rate for some sorbents	• Select new stone
Nitrogen Oxide	Minimized during combustion (demonstrated)	• Promote reducing conditions in lower region of the bed	
Materials	Conventional boiler tube materials	• Use higher-grade materials (which are available)	
Coal Feed	Petrocarb feed system (lockhoppers)	• Increase number of feed points per bed • Reduce unit capacity: bed depth	• Alternative technology e.g., slurry feed, screw feeders
Alkali Metals[1]	Temperature maintained sufficiently low to avoid problem	• Lower temperature further to avoid problem	• Add sorbent to remove alkali metals • Modify turbine operation
Turndown and Load Follow	Vary bed temperature modular boilers	• Vary excess air	• Additional modules • Recirculating bed
Spent Stone Disposal	Landfill	• Sulfur recovery • Commercial utilization	

[1] Control to achieve gas-turbine reliability and long life

The use of a low-Btu fuel gas gasifier greatly reduces the problem of corrosion and deposition in the pressurized boiler and gas turbine. Although this in turn reduces the cost and improves the reliability of these units, other penalties are incurred, as for instance, the steam supply, auxiliary power input, and auxiliary compressor required by a gasifier.

Both the fluidized bed and suspension-type gasifiers give promise of reduced cost relative to fixed bed-type gasifiers, but they are still experimental. This means that their cost and performance have not yet been verified on a commercial scale. Greater detail on the state of the art with regard to gasifiers is contained in Section 4.

It should be emphasized once more that the thermodynamic performance advantage of higher cycle operating temperatures implies the concomitant penalty of increased material cost and/or corrosion rates and potentially decreased plant reliability. Reliability is a problem of considerable concern to the utility industry. It was reported in the January 1, 1975 issue of Electrical World that one large utility experienced an average availability of 69% for five new 500-to-800 MWe coal-fired units. This was a decrease from earlier availability experience.

12.2 Description of Parametric Points Investigated

For purposes of this study, three types of advanced steam power plants were chosen for parametric analysis:

- Atmospheric furnace system
- Pressurized boiler-gasifier system
- Pressurized fluidized bed boiler system.

The following paragraphs give a general description of those plants. Sections 12.2.4 to 12.2.6 explain the parametric points investigated.

12.2.1 Atmospheric Furnace System

The atmospheric furnace steam plant is the familiar power plant used extensively by the electrical utilities. It varies widely in size

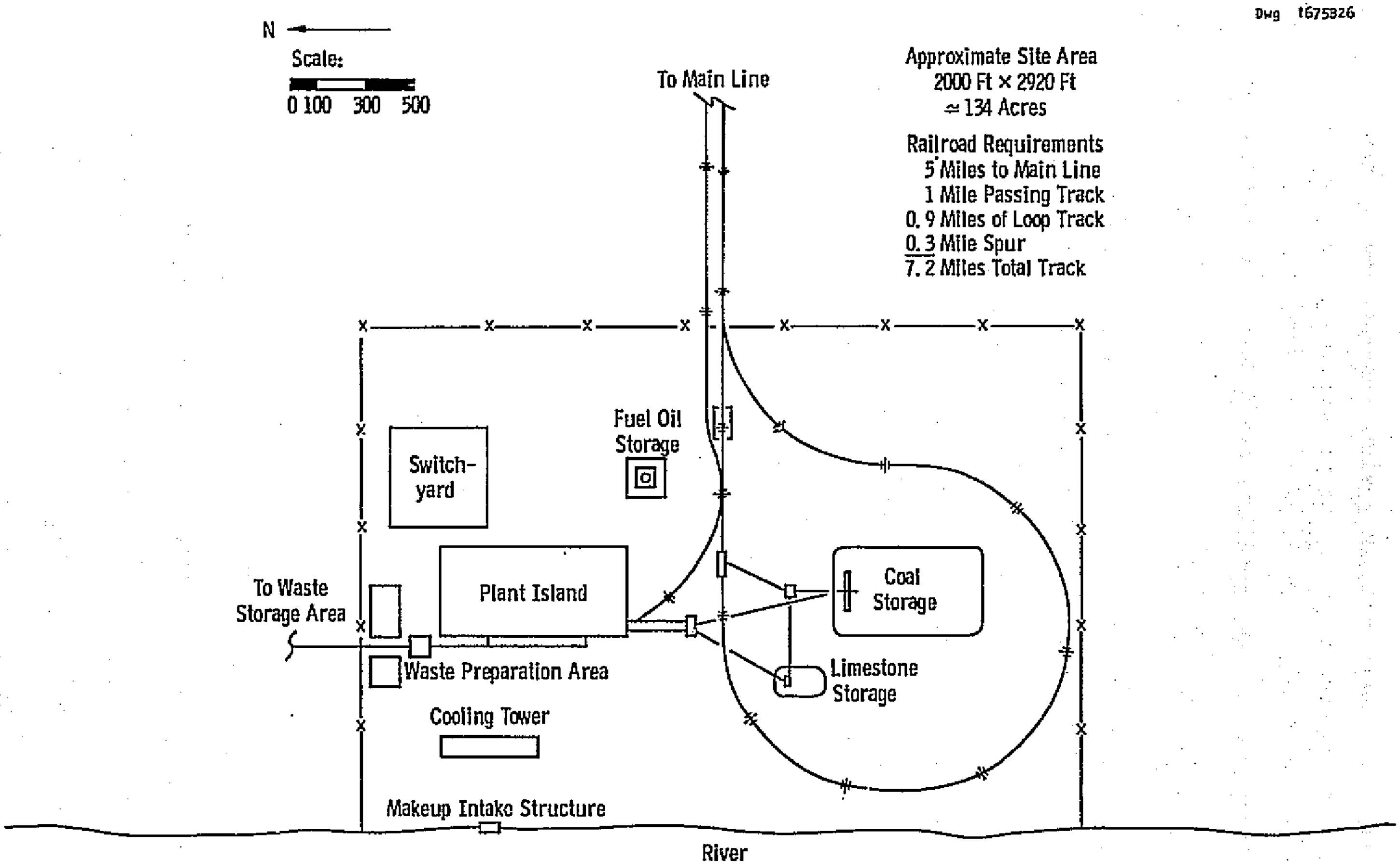

Fig. 12.2—Atmospheric boiler advanced steam, site layout, Base Case (Point 20)

and in details of construction. All plants, however, have the following major components in common:

- Steam boiler
- Steam turbine-generator
- Condenser
- Feedwater heaters
- Boiler feedwater pumps
- Stack-gas cleanup and treatment equipment
- Draft fans
- Stack.

The largest single component is the steam boiler. For the base case 500 MWe plant the gross dimensions and weights of particular major components are given in Table 12.16 (See Section 12.5.4).

Based on these major component dimensions, nominal coal and dolomite consumption rates, and standard power plant practice the plant site layout was designed by Chas. T. Main, Inc. and is shown in Figure 12.2.

As the temperature (and/or pressure) of the steam is increased, the general size and appearance of the plant does not change significantly. Rather, the materials at the hot end of the cycle are improved (at a cost increase, of course) and/or increased in thickness.

Because this type of plant burns the coal directly without treatment other than drying and grinding, the combustion products are both mechanically treated for particulate removal and chemically treated for sulfur removal to satisfy environmental requirements. As a result, combustion product treatment equipment is both large and expensive.

An alternative atmospheric system that was investigated incorporates a boiler which is designed with a fluidized bed furnace with in-bed desulfurization. One potential cost advantage of this type of boiler is the elimination of the scrubber to remove sulfur from the stack gases. Another potential cost reduction stems from the high convection heat transfer coefficient on the exterior of the boiler tubes due to the fluidized bed action. These capital cost reductions are discounted to some degree by an increased dolomite usage rate which increases the operating cost of the plant. The higher dolomite usage rate results from the desulfurization reaction occurring at a much higher temperature in the furnace than in the stack-gas scrubber.

12.2.2 Pressurized Boiler-Gasifier System

The pressurized boiler-gasifier system differs from the standard atmospheric furnace system in three ways. First, the boiler is pressurized on the combustion side to reduce its size by improving the fire-side heat transfer coefficient. Secondly, it has a gas turbine set to produce the pressurized combustion air for the boiler and to produce electrical power from the excess power of the gas turbine. Thirdly, it has an integrated coal gasification subsystem that receives pressurized process air from the gas turbine compressor and delivers clean low-Btu fuel gas to the boiler and gas turbine combustor. Thus this power plant has the following major components:

- Steam boiler
- Steam turbine-generator
- Condenser
- Feedwater heaters
- Boiler feedwater pumps
- Gas turbine-generator
- Stack-gas coolers
- Stack
- Coal gasifier.

Note that the stack-gas cleanup equipment has been eliminated since the coal-cleaning equipment is incorporated in the gasifier subsystem. Note further the addition of stack-gas coolers. These are necessary heat recovery units designed to extract heat from the gas turbine outlet gas before discharging it up the stack.

For the base case 700 MWe plant (approximately 500 MWe from steam turbine and 200 MWe from the pressurizing gas turbine) the gross dimensions and weights of particular major components are given in Table 12.16 (see Section 12.5.4).

The site layout for this plant is shown in Figure 12.3.

As in the case of the atmospheric furnace system, the general size and appearance of the plant does not change significantly as the peak temperatures and/or pressures of the working fluids (air and steam, in this case) are increased.

12.2.3 Pressurized Fluidized Bed Boiler System

The pressurized fluidized bed boiler system is similar to the pressurized boiler-gasifier system in that it incorporates a gas turbine to pressurize the boiler and to produce net electrical power. The coal, however, is simply dried, crushed, and added directly to the boiler. The boiler has a compact construction because the combustion occurs in a fluidized bed which achieves a high convection heat transfer coefficient. Dolomite is added directly to the fluidized bed to chemically remove the sulfur in the coal. Elutriated particulates are removed in pressurized separators downstream of the boiler before the combustion products enter the gas turbine. The major plant components are:

- Steam boiler
- Steam turbine-generator
- Condenser
- Feedwater heaters
- Boiler feedwater pumps
- Gas turbine-generator
- Stack-gas coolers
- Stack

For the base case 700 MWe plant (approximately 500 MWe from the steam turbine generator and 200 MWe from the gas turbines) the gross dimensions and weights of particular major components are given in Table 12.16 (see Section 12.5.4).

The site layout for this plant is shown in Figure 12.4.

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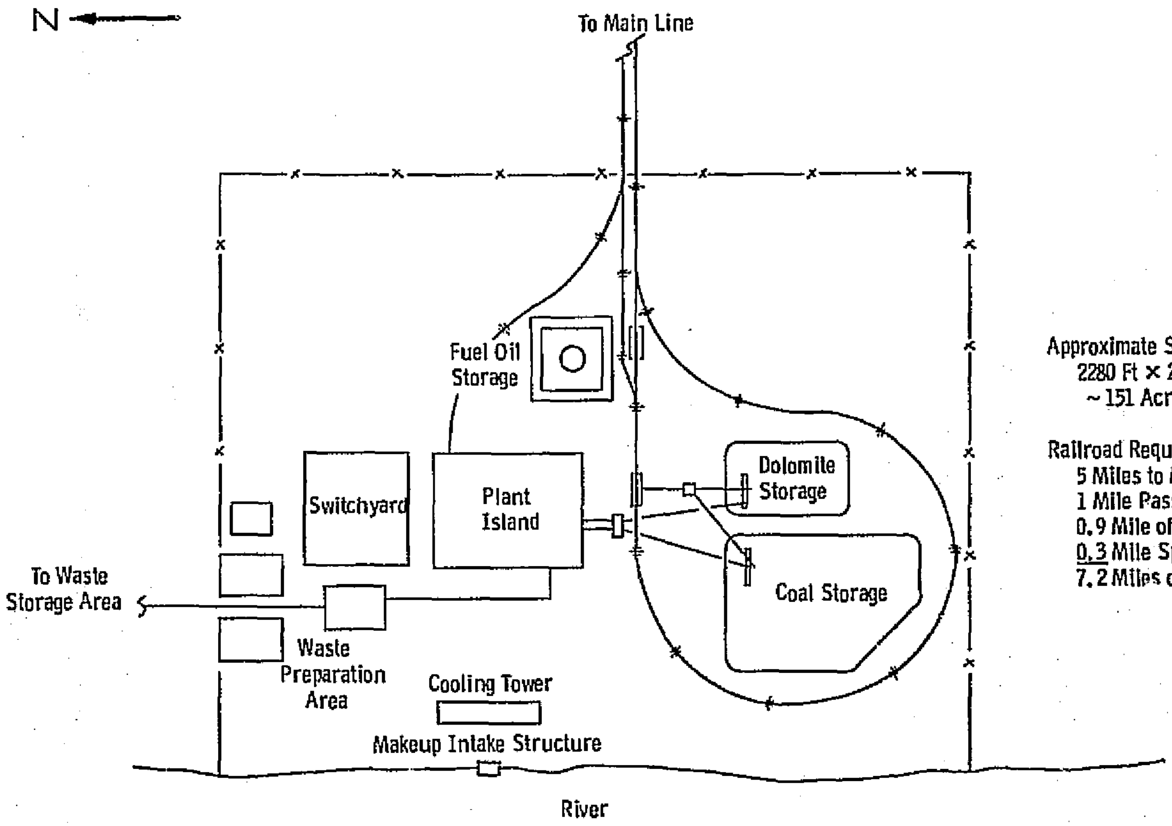


Approximate Site Area:
2280 Ft × 2880 Ft
~151 Acres

Railroad Requirements:
5 Miles to Main Line
1 Mile Passing Track
0.9 Mile of Loop Track
0.3 Mile Spur
7.2 Miles of Total Track

Fig. 12.3 Pressurized boiler advanced steam site layout, Base Case (Point 16)

Scale:
0 100 300 500

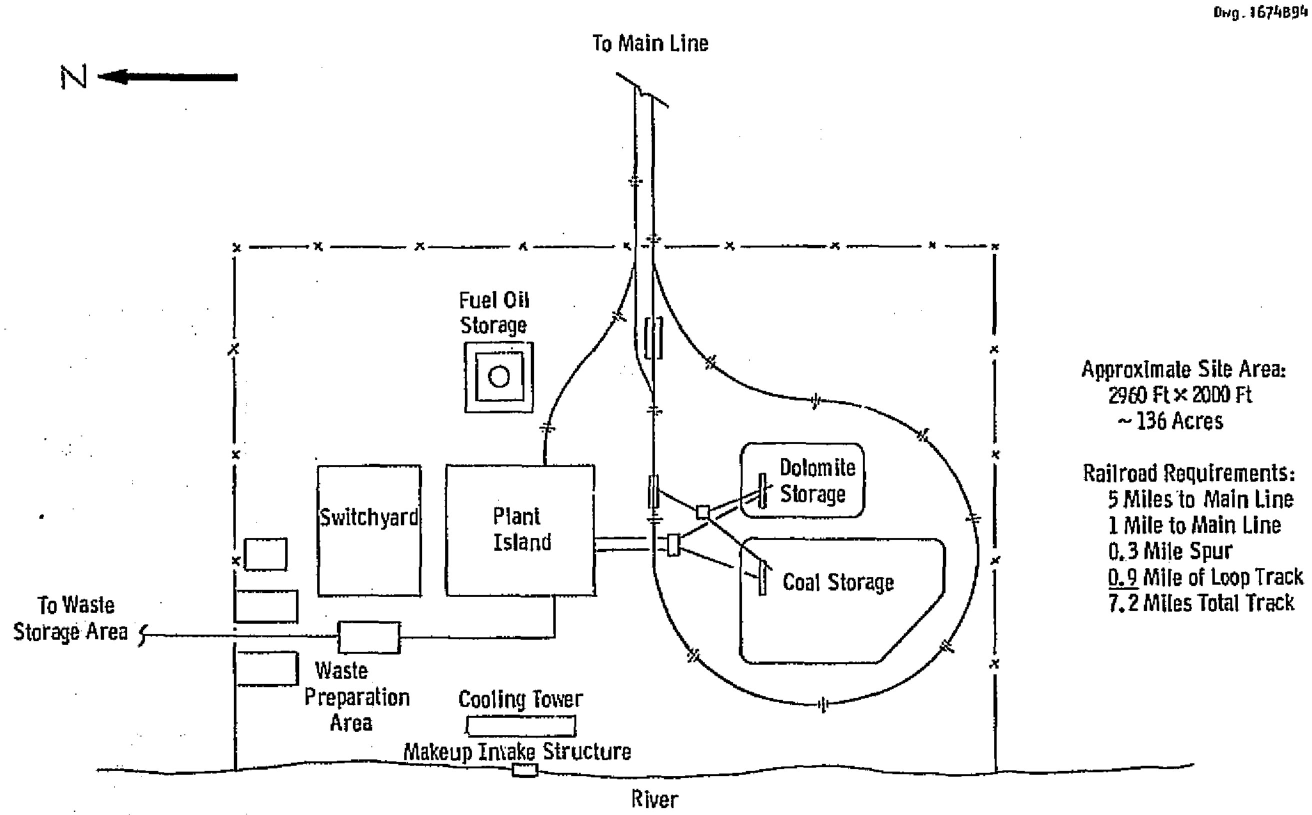
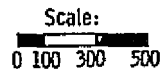


Fig. 12. 4 – Pressured fluidized bed boiler advanced steam site layout, Base Case (Point 7)



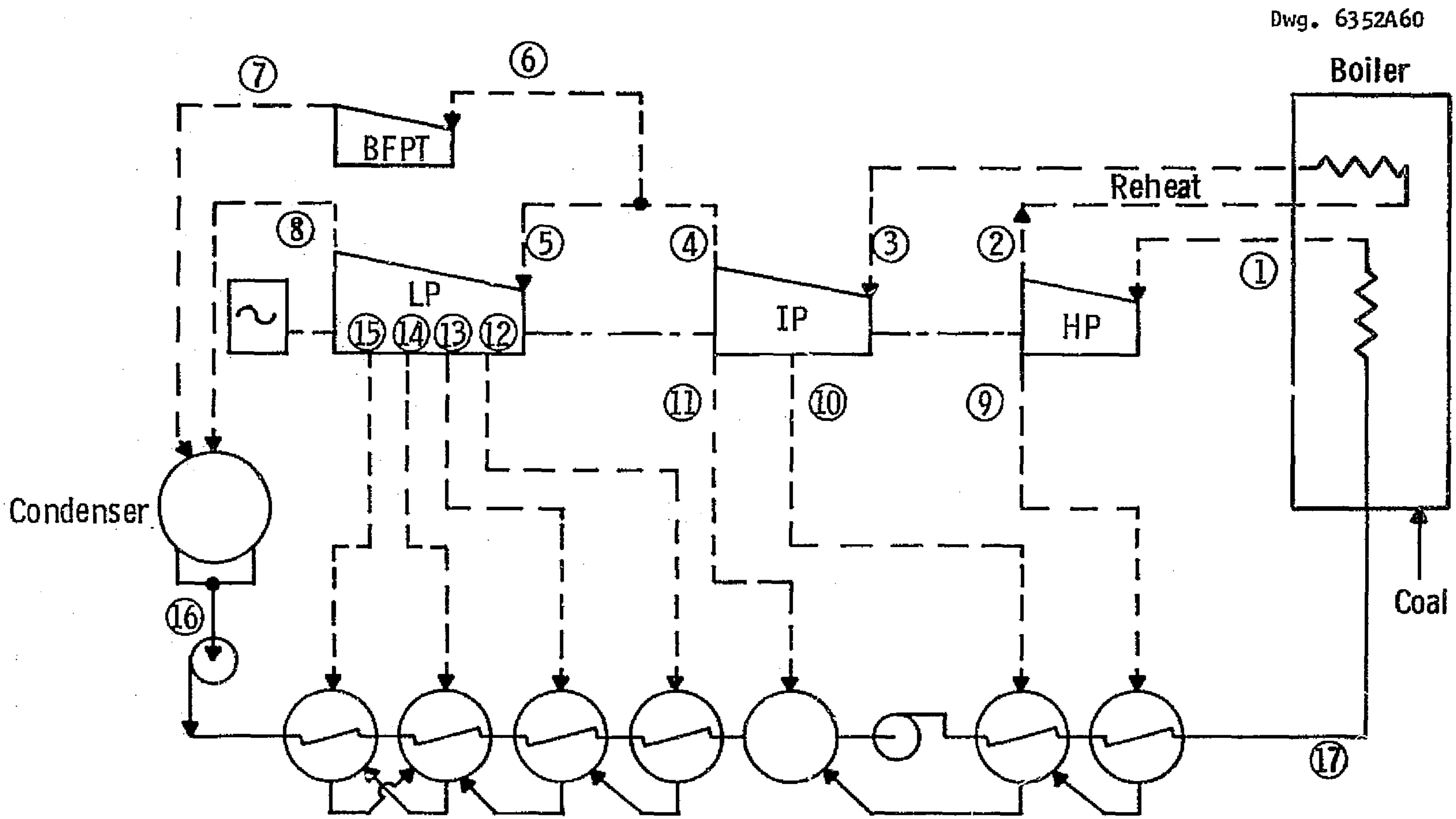


Fig. 12.5—Schematic of atmospheric furnace steam plant

As in the case of the other two power plant systems, the general size and appearance of the plant does not change significantly as the peak temperatures and/or pressures of the working fluids are increased.

12.2.4 Atmospheric Furnace System Parameters

The choice of performance variables to investigate parametrically depends, of course, upon the thermodynamic cycle of the power plant. A typical schematic cycle diagram for an atmospheric furnace steam plant is shown in Figure 12.5. The parameters investigated for this cycle are essentially those designated by NASA. Table 12.3 gives the parametric points for which performance and energy costs were calculated, as well as the performance calculation results. (The calculated results are analyzed and shown graphically in Sections 12.4 and 12.6).

The two primary variables are the steam temperature and pressure. Temperature was varied, from the standard value of 811°K (1000°F) that is currently in extensive use commercially, up to the 1033°K (1400°F) level specified by NASA. The pressure levels investigated were 16.547, 24.132, and 34.474 MPa (2400, 3500, and 5000 psi). In addition, some thermodynamic performance calculations were made for a 68.948 MPa (10,000 psi) level, but the turbine and boiler were so far from practicable that no price was estimated for them.

The number of reheats was varied from none to two. The effect of condenser pressure variation from 6.754 to 30.393 kPa (2 to 9 in Hg) abs was investigated, along with a corresponding change in the method and cost of heat rejection.

The bulk of the parametric points was calculated at a nominal power rating of 500 MWe. A representative number were repeated at a nominal power rating of 900 MWe to determine the effect of scale on energy cost.

Finally, the capital cost and performance effects of the three coals designated by NASA were investigated for both a standard furnace and a fluidized bed furnace.

TABLE 12.3 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (ATMOSPHERIC FURNACE STEAM PLANT)

Parametric Point	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Power Output, MWe	464	464	457	464	464	465	465	465	466	466	466	467	465	465	464	464	465	464
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subbituminous Coal																		
Lignite Coal																		
Furnace Type																		
Atmospheric (Conventional)	X	X	X	X	X		X	X		X	X		X	X	X	X	X	X
Fluid Bed						X			X			X						
Steam Turbine																		
Throttle Press, psia	10000	10000	10000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	3500	3500	3500	3500
Throttle Temp, °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1400	1400	1400	1000	1000	1000	1000	1000	1000
First Reheat Temp, °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1400	1400	1400	1200	1000	1000	1000	1200	1000
Second Reheat Temp, °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1400	1400	1400	1200	1200	1000	1000	1200	1000
Third Reheat Temp, °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Condenser Press, in. Hg Abs	2	3.5	9	2	3.5	3.5	2	3.5	3.5	2	3.5	3.5	2	2	2	3.5	2	3.5
Thermodynamic Eff, % ①	46.1	44.9	42.0	45.7	44.5	44.5	48.8	47.5	47.5	51.3	50.1	50.1	47.7	48.1	45.3	44.2	47.1	45.9
Powerplant Eff, %	36.9	35.9	33.2	36.6	35.6	35.4	39.0	38.1	37.9	41.1	40.1	39.9	38.2	38.5	36.3	35.4	37.7	36.7
Overall Eff, %	36.9	35.9	33.2	36.6	35.6	35.4	39.0	38.1	37.9	41.1	40.1	39.9	38.2	38.5	36.3	35.4	37.7	36.7
Total Capital Cost $\times 10^{-6}$, $	730.1	729.5	740.7	252.4	251.5	212.2	396.3	395.9	325.8	593.9	587.5	472.3	355.5	381.4	239.1	236.5	353.1	318.5
Capital Costs, $/kWe	1572.9	1571.9	619.1	544.2	542.3	456.1	852.4	851.8	598.4	1275.1	1251.2	1010.8	765.2	820.6	515.7	509.9	759.9	685.9
Cost of Elect, Mills/kWh																		
Capital	49.722	49.690	51.184	17.204	17.143	14.417	26.946	26.927	27.079	40.307	39.869	31.955	24.191	25.942	16.302	16.118	24.021	21.684
Fuel ②	7.861	8.073	8.739	7.930	8.146	9.202	7.429	7.618	7.661	7.063	7.231	7.264	7.600	7.540	8.001	8.206	7.692	7.896
Oper. & Maint.	1.132	1.145	1.111	1.138	1.152	2.068	1.106	1.118	1.974	1.083	1.093	1.905	1.117	1.113	1.143	1.152	1.118	1.135
Total	58.72	58.91	61.04	26.27	26.44	24.69	36.48	35.66	31.71	48.45	48.19	41.12	32.91	34.60	25.45	25.48	32.83	30.32
Est. Time of Construction, yr	6.0	6.0	6.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5 0	5.0	5.0	5.0	5.0

Notes:
① Where Applicable
② Use Base Delivered Fuel Cost

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TABLE 12.3 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (ATMOSPHERIC FURNACE STEAM PLANT)(cont'd)

Sheet 2 of 4

Parametric Point	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
Power Output, MWe	463	463	456	464	464	466	465	465	467	464	464	465	466	465	466	466	464	465
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X			X
Subbituminous Coal																X		
Lignite Coal																	X	
Furnace Type																		
Atmospheric (Conventional)	X	X	X	X	X		X	X		X	X	X		X		X	X	
Fluid Bed						X			X				X		X			X
Steam Turbine																		
Throttle Press., psia	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Throttle Temp., °F	1000	1000	1000	1200	1200	1200	1400	1400	1400	1000	1000	1200	1200	1400	1400	1000	1000	1000
First Reheat Temp., °F	1000	1000	1000	1200	1200	1200	1400	1400	1400	1200	1400	1400	1400			1000	1000	1000
Second Reheat Temp., °F																		
Third Reheat Temp., °F																		
Condenser Press., in. Hg Abs	2	3.5	9	2	3.5	3.5	2	3.5	3.5	2	2	2	2	2	2	3.5	3.5	3.5
Thermodynamic Eff., % ①	44.5	43.4	40.5	47.4	46.1	46.1	49.6	48.3	48.3	45.8	47.1	48.5	48.5	47.5	47.5	43.4	43.4	43.4
Powerplant Eff., %	35.6	34.7	32.0	37.9	36.9	36.7	39.7	38.7	38.5	35.6	37.7	38.8	38.6	38.0	37.8	35.0	33.5	34.4
Overall Eff., %	35.6	34.7	32.0	37.9	36.9	36.7	39.7	38.7	38.5	35.6	37.7	38.8	38.6	38.0	37.8	35.0	33.5	34.4
Total Capital Cost $\times 10^{-6}$, $	232.8	231.1	252.4	290.0	288.2	282.6	378.9	378.2	347.0	268.4	296.3	324.9	289.0	345.3	311.5	232.8	245.1	203.0
Capital Costs, $/kWe	502.4	498.7	553.0	624.3	620.3	542.0	814.4	812.7	743.4	567.9	638.0	698.9	619.7	743.2	668.5	450.0	527.9	436.6
Cost of Elect., Mills/kWh																		
Capital	15.883	15.767	17.483	19.735	19.610	17.134	25.744	25.692	23.501	17.954	20.168	22.093	19.680	23.496	21.131	15.806	16.689	13.803
Fuel ②	8.149	8.363	9.075	7.655	7.851	7.899	7.306	7.490	7.529	7.922	7.697	7.469	7.507	7.627	7.670	8.296	8.648	8.424
Oper. & Maint.	1.153	1.166	1.127	1.121	1.133	2.016	1.098	1.110	1.951	1.136	1.123	1.109	1.948	1.119	1.976	.894	.912	2.107
Total	25.19	25.30	27.69	28.511	28.59	27.05	34.15	34.29	32.98	27.01	28.99	30.67	29.05	32.24	30.78	25.00	26.25	24.33
Est. Time of Construction, yr	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Notes:
① Where Applicable
② Use Base Delivered Fuel Cost

TABLE 12.3 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (ATMOSPHERIC FURNACE STEAM PLANT) (cont'd)

Sheet 3 of 4

Parametric Point	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
Power Output, MWe	465	466	464	463	465	456	464	464	466	457	464	466	464	465	464	458	835	835
Fuel																		
Bituminous Coal			X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subbituminous Coal	X																	
Lignite Coal		X																
Furnace Type																		
Atmospheric (Conventional)			X	X		X	X	X		X	X		X	X	X	X	X	X
Fluid Bed	X	X			X				X			X						
Steam Turbine																		
Throttle Press, psia	3500	3500	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400	5000	5000
Throttle Temp, °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1200	1400	1400	1000	1200	1200	1200	1000	1000
First Reheat Temp, °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1200			1200	1400	1400	1400	1000	1000
Second Reheat Temp, °F																	1000	1000
Third Reheat Temp, °F																		
Condenser Press, in. Hg Abs	3.5	3.5	2	3.5	3.5	9	2	3.5	3.5	9	2	2	2	2	3.5	9	2	3.5
Thermodynamic Eff, % (1)	43.4	43.4	43.7	42.5	42.6	39.8	46.2	45.1	45.1	42.2	46.5	46.5	45.1	47.5	46.2	43.4	46.1	44.7
Powerplant Eff, %	35.0	33.5	34.9	34.0	33.8	31.4	37.0	36.1	35.8	33.3	37.2	37.0	36.0	38.0	37.0	34.4	36.9	35.8
Overall Eff, %	35.0	33.5	34.9	34.0	33.8	31.4	37.0	36.1	35.8	33.3	37.2	37.0	36.0	38.0	37.0	34.4	36.9	35.8
Total Capital Cost $\times 10^{-6}$, $	223.3	231.9	223.0	220.2	199.1	241.8	281.2	278.9	246.3	300.7	334.8	296.3	252.8	313.8	312.2	334.7	412.8	413.0
Capital Costs, $/kWe	479.5	499.4	481.7	475.6	428.4	530.5	606.0	600.9	528.9	657.3	721.2	636.2	545.4	575.6	672.1	730.6	494.3	494.6
Cost of Elect, Mills/kWh																		
Capital	5.159	5.787	15.228	15.034	13.543	16.770	19.157	18.997	16.719	20.778	22.799	26.112	17.241	21.356	21.25	23.097	15.625	15.636
Fuel (2)	8.296	8.648	9.308	8.522	8.587	9.245	7.843	8.040	8.093	8.701	7.794	7.840	8.049	7.637	7.834	8.444	7.870	8.113
Oper. & Maint.	.894	.912	1.157	1.170	2.130	1.130	1.127	1.139	2.044	1.103	1.124	2.000	1.140	1.114	1.126	1.091	.864	.879
Total	24.35	25.35	24.69	24.73	24.26	27.15	28.13	28.18	26.86	30.58	31.72	29.95	26.43	30.11	30.21	32.63	24.36	24.63
Est. Time of Construction, yr	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.5	5.5

Notes:
(1) Where Applicable
(2) Use Base Delivered Fuel Cost

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TABLE 12.3 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (ATMOSPHERIC FURNACE STEAM PLANT) (cont'd)

Sheet 4 of 4

Parametric Point	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72
Power Output, MWe	837	837	839	839	835	835	836	836	834	836	836	836	838	837	834	834	836	835
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subbituminous Coal																		
Lignite Coal																		
Furnace Type																		
Atmospheric (Conventional)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Fluid Bed																		
Steam Turbine																		
Throttle Press, psia	5000	5000	5000	5000	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	2400	2400	2400	2400
Throttle Temp, °F	1200	1200	1400	1400	1000	1000	1000	1000	1000	1000	1200	1200	1400	1400	1000	1000	1200	1200
First Reheat Temp, °F	1200	1200	1400	1400	1000	1000	1200	1200	1000	1000	1200	1200	1400	1400	1000	1000	1200	1200
Second Reheat Temp, °F	1200	1200	1400	1400	1000	1000	1200	1200										
Third Reheat Temp, °F																		
Condenser Press, In. Hg Abs	2	3 5	2	3.5	2	3.5	2	3.5	2	3.5	2	3.5	2	3.5	2	3.5	2	3.5
Thermodynamic Eff, % ①	49.2	47.7	51.6	50.2	45.7	44.3	47.4	46.0	44.8	43.5	47.6	46.2	49.8	48.4	44.0	42.7	46.5	45.2
Powerplant Eff, %	39.4	38.2	41.3	40.2	36.5	35.5	38.0	36.9	35.8	34.9	38.1	37.0	39.9	38.7	35.1	34.2	37.2	36.2
Overall Eff, %	39.4	38.2	41.3	40.2	36.5	35.5	38.0	36.9	35.8	34.9	38.1	37.0	39.9	38.7	35.1	34.2	37.2	36.2
Total Capital Cost $\times 10^{-6}$, \$	609.7	611.7	891.5	881.4	394.6	393.9	495.2	494.2	385.6	381.1	464.7	464.0	588.1	588.7	369.7	367.8	430.2	429.3
Capital Costs, \$/kWe	728.2	730.8	1062.8	1051.1	472.6	471.9	592.2	591.2	462.2	455.9	555.7	555.0	702.0	702.9	443.5	441.2	514.9	513.3
Cost of Elect, Mills/kWh																		
Capital	23.021	23.101	33.599	33.226	14.940	14.917	18.722	18.688	14.611	14.412	17.566	17.544	22.193	22.221	14.019	13.948	16.277	16.247
Fuel ②	7.368	7.593	7.019	7.217	7.942	8.178	7.640	7.858	8.101	8.322	7.615	7.839	7.275	7.485	8.258	8.490	7.800	8.024
Oper. & Maint.	.832	.846	.811	.823	.869	.883	.850	.864	.879	.878	.848	.862	.827	.840	.883	.897	.854	.853
Total	31.22	31.54	41.43	41.27	23.75	23.98	27.21	27.42	23.59	23.61	26.03	26.25	30.29	30.55	23.16	23.34	24.93	25.14
Est. Time of Construction, yr	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5

Notes:
① Where Applicable
② Use Base Delivered Fuel Cost

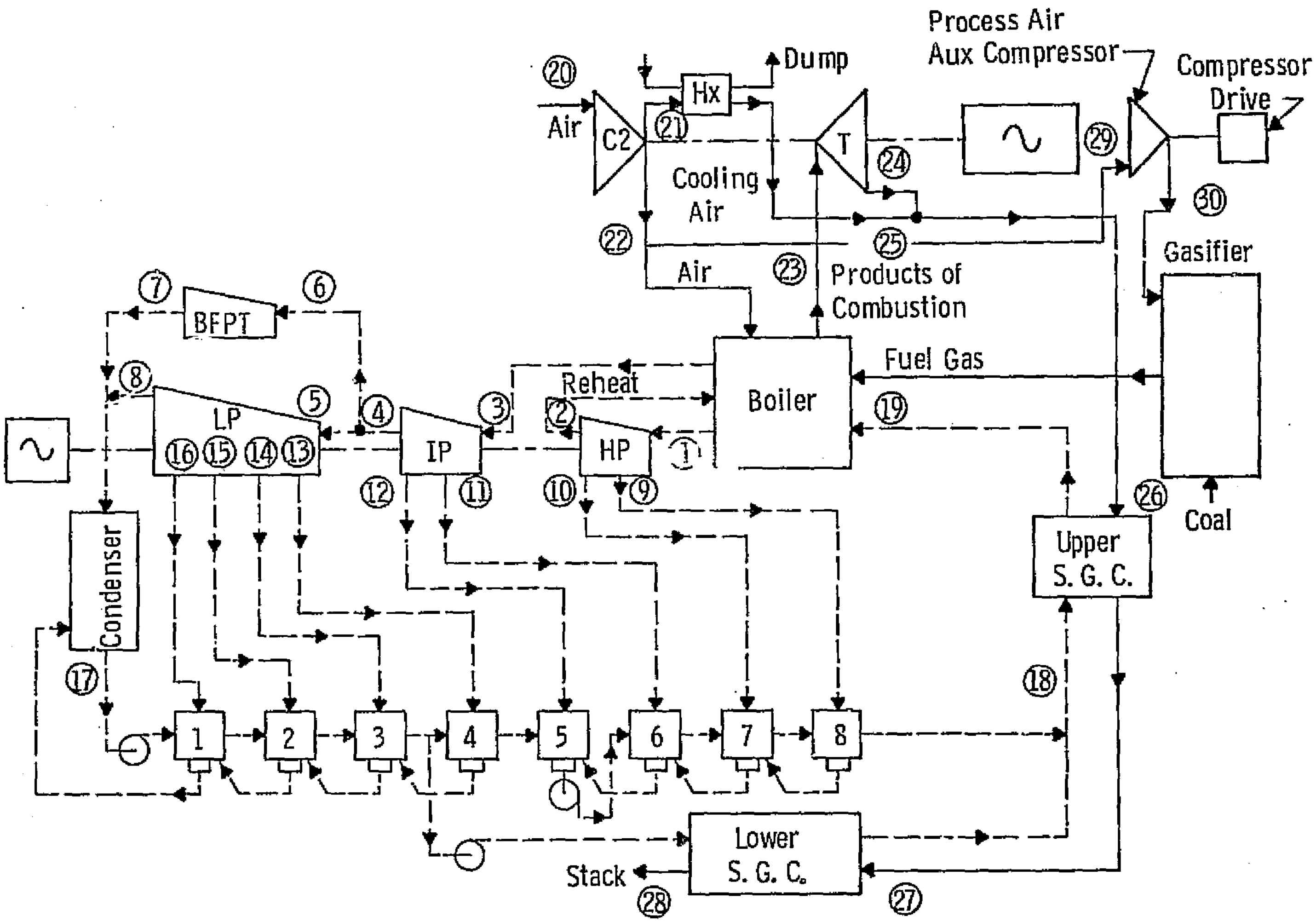

Fig. 12.6—Schematic of pressurized boiler power plant

12.2.5 Pressurized Boiler-Gasifier System Parameters

Figure 12.6 is a schematic cycle diagram of this system which incorporates a gas turbine that serves both to raise the pressure on the combustion side of the boiler and to produce net electric power. In addition, the gas turbine supplies process air to the gasifier, although an auxiliary compressor is required to overcome the substantial pressure drop incurred by the gasifier.

Table 12.4 gives the parametric points for which performance and energy costs were calculated, as well as the performance calculation results. (The calculated results are analyzed and shown graphically in Sections 12.4 and 12.6).

The primary variables of the gas turbine are the turbine inlet temperature and the compressor (cycle) pressure ratio. The temperature was varied from 1144 to 1644°K (1600 to 2500°F), and the pressure ratio ranged from 8:1 to 25:1.

The airflow entering the gas turbines is fixed (for constant ambient conditions), but the amount of fuel burned in the boiler varies the amount of steam raised in the boiler. The theoretical limit of fuel addition is that corresponding to a stochiometric fuel/air ratio entering the gas turbine. The fuel addition was varied such that the amount of steam generated in the boiler varied from approximately 315 to 504 kg/s (2.5×10^6 to 4×10^6 lb/hr).

Similarly to the atmospheric furnace system, back pressure was varied from 6.754 to 30.392 kPa (2 to 9 in Hg)abs. Also, the effect of operation with the three coals was examined.

Finally, a limited number of points were run with steam conditions up to 34.474 MPa (5000 psi) and 1033°K (1400°F).

12.2.6 Pressurized Fluidized Bed Boiler System Parameters

The parametric variation for this system is essentially the same as in the previous system. In this case, however, the gas turbine inlet temperature was limited to 1255°K (1800°F) because the desulfurization

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TABLE 12.4—ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (PRESSURIZED BOILER GASIFIER SYSTEM)

Sheet 1 of 3

Parametric Point	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Power Output, MWe	667	580	484	668	582	486	662	573	477	642	555	458	714	628	535	724	635	541
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subbituminous Coal																		
Lignite Coal																		
Gas Turbine																		
Inlet Temp., °F	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	2000	2000	2000	2000	2000	2000
Pressure Ratio	8	8	8	10	10	10	15	15	15	20	20	20	8	8	8	10	10	10
Air Equivalence Ratio (Nominal)	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8
Steam Turbine																		
Throttle Press., psia	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Throttle Temp., °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Temp., °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Condenser Press., in Hg Abs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Thermodynamic Eff. ①																		
Powerplant Eff., %	35.6	35.7	36.0	35.5	35.6	35.8	35.0	35.0	35.1	34.0	33.9	33.8	37.5	37.7	38.2	37.4	37.7	38.1
Overall Eff., %	35.6	35.7	36.0	35.5	35.6	35.8	35.0	35.0	35.1	34.0	33.9	33.8	37.5	37.7	38.2	37.4	37.7	38.1
Total Capital Cost $\times 10^{-6}$, \$	400.7	352.7	301.7	400.8	353.7	302.4	404.1	356.0	304.0	400.7	352.4	299.9	420.6	372.9	321.2	425.4	376.2	323.1
Capital Costs, \$/kWe	601.1	607.8	623.0	600.0	608.0	622.0	610.4	621.3	537.0	624.6	635.1	654.7	588.7	593.1	599.9	587.9	592.2	597.2
Cost of Elect., Mills/kWh																		
Capital	19.001	19.213	19.695	18.967	19.219	19.663	19.297	19.641	20.137	19.745	20.078	20.696	18.611	18.751	18.964	18.584	18.722	18.880
Fuel ②	8.152	8.127	8.057	8.165	8.147	8.098	8.293	8.280	8.274	8.538	8.570	8.585	7.744	7.689	7.603	7.760	7.688	7.604
Oper. & Maint.	1.562	1.620	1.699	1.563	1.621	1.702	1.582	1.645	1.734	1.628	1.698	1.797	1.478	1.524	1.587	1.477	1.519	1.581
Total	28.72	28.96	29.45	28.69	28.99	29.46	29.17	29.57	30.15	29.91	30.35	31.09	27.83	27.96	28.15	27.82	27.93	28.07
Est. Time of Construction, yr	5.9	5.8	5.6	5.9	5.8	5.6	5.9	5.8	5.6	5.9	5.7	5.5	6.0	5.9	5.7	6.0	5.9	5.7

Notes:
① Where Applicable
② Use Base Delivered Fuel Cost

Dwg. 257C216

TABLE 12.4—ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (PRESSURIZED BOILER GASIFIER SYSTEM) (CONT'D)

Sheet 2 of 3

Parametric Point	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
Power Output, MWe	733	639	542	720	629	530	792	703	607	806	715	618	803	711	612	771	680	583
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subbituminous Coal																		
Lignite Coal																		
Gas Turbine																		
Inlet Temp. °F	2000	2000	2000	2000	2000	2000	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500	2500
Pressure Ratio	15	15	15	20	20	20	10	10	10	15	15	15	20	20	20	25	25	25
Air Equivalence Ratio	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8
Steam Turbine																		
Throttle Press., psia	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Throttle Temp., °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Temp., °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Condenser Press., in Hg Abs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Thermodynamic Eff., ①																		
Powerplant Eff., %	37.0	37.4	37.7	36.1	36.3	36.8	39.5	39.9	40.6	39.4	39.8	40.4	38.7	39.1	39.6	36.6	36.9	37.4
Overall Eff., %	37.0	37.4	37.7	36.1	36.3	36.8	39.5	39.9	40.6	39.4	39.8	40.4	38.7	39.1	39.6	36.6	36.9	37.4
Total Capital Cost $\times 10^{-6}$, $	432.6	387.4	329.9	432.3	382.0	327.8	458.5	406.9	352.9	470.3	420.0	364.8	474.8	423.4	367.6	476.7	423.0	364.9
Capital Costs, $/kWe	590.2	606.1	608.2	600.4	606.9	618.6	578.8	579.0	581.6	583.3	587.0	590.8	591.5	595.4	600.2	618.6	621.9	625.7
Cost of Elect, Mills/kWh																		
Capital	18.658	19.160	19.228	18.981	19.184	19.563	18.298	18.303	18.386	18.439	18.557	18.675	18.697	18.822	18.972	19.555	19.660	19.778
Fuel ②	7.847	7.763	7.689	8.038	7.995	7.892	7.338	7.265	7.148	7.358	7.287	7.177	7.493	7.426	7.323	7.930	7.865	7.763
Oper. & Maint.	1.479	1.525	1.590	1.511	1.561	1.627	1.381	1.418	1.465	1.376	1.412	1.459	1.394	1.432	1.481	1.465	1.506	1.559
Total	27.98	28.45	28.51	28.53	28.74	29.08	27.02	26.99	27.00	27.17	27.26	27.31	27.68	27.68	27.78	28.95	29.03	29.10
Est. Time of Construction, yr	6.0	5.9	5.7	6.0	5.9	5.7	6.1	6.0	5.8	6.1	6.0	5.8	6.1	6.0	5.8	6.1	5.9	5.8

Notes: ① Where Applicable
② Use Base Delivered Fuel Cost

Dwg. 257C217

TABLE 12.4 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (PRESSURIZED BOILER GASIFIER SYSTEM) (CON'TD.)

Sheet 3 of 3

Parametric Point	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
Power Output, MWe	732	648	554	682	599	511	783	688	583	824	723	611	724	635	541	723	634	540
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X						
Subbituminous Coal													X	X	X			
Lignite Coal																X	X	X
Gas Turbine																		
Inlet Temp, °F	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
Pressure Ratio	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Air Equivalence Ratio (Nominal)	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8
Steam Turbine																		
Throttle Press, psia	3500	3500	3500	3500	3500	3500	4500	4500	4500	5000	5000	5000	3500	3500	3500	3500	3500	3500
Throttle Temp, °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1400	1400	1400	1000	1000	1000	1000	1000	1000
Reheat Temp, °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1400	1400	1400	1000	1000	1000	1000	1000	1000
Condenser Press, in Hg Abs	2.0	2.0	2.0	9.0	9.0	9.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Thermodynamic Eff, ①																		
Powerplant Eff, %	37.8	38.5	39.0	35.2	35.6	36.0	40.5	40.7	41.0	42.3	42.4	42.6	37.6	37.9	38.4	36.7	37.1	37.5
Overall Eff, %	37.8	38.5	39.0	35.2	35.6	36.0	40.5	40.7	41.0	42.3	42.4	42.6	37.6	37.9	38.4	36.7	37.1	37.5
Total Capital Cost $\times 10^{-6}$, $	432.0	383.3	330.7	436.2	385.9	331.8	536.8	470.0	399.7	700.4	607.6	507.1	390.6	346.1	297.3	412.3	356.3	305.9
Capital Costs, $/kWe	589.9	591.9	597.4	639.5	643.7	649.4	685.7	683.4	685.1	849.8	840.9	830.5	639.3	544.7	549.3	570.2	561.7	566.1
Cost of Elect, Mills/kWh																		
Capital	18.648	18.710	18.885	20.215	20.348	20.530	21.676	21.604	21.689	26.865	26.583	26.254	17.047	17.220	17.365	18.025	17.757	17.897
Fuel ②	7.668	7.541	7.433	8.231	8.144	8.051	7.169	7.126	7.083	6.865	6.836	6.805	7.714	7.646	7.563	7.899	7.829	7.744
Oper. & Maint.	1.458	1.492	1.549	1.495	1.542	1.607	1.388	1.412	1.478	1.306	1.352	1.419	.848	.900	.968	.873	.924	.993
Total	27.77	27.74	27.87	29.94	30.03	30.188	30.21	30.14	30.25	36.04	34.77	34.48	25.61	25.77	25.90	26.80	26.51	26.63
Est. Time of Construction, yr	6.0	5.9	5.7	5.9	5.8	5.7	6.1	5.9	5.8	6.1	6.0	5.8	6.0	5.9	5.7	6.0	5.9	5.7

Notes: ① Where Applicable
② Use Base Delivered Fuel Cost

process in the boiler fluidized bed is temperature-limited. Further, within the restraints of the system as hypothesized, there is no clean fuel gas available to reheat the combustion products just before they enter the gas turbine.

The schematic cycle diagram of this system shown in Figure 12.7 is slightly simpler than that of the previous system because the gasifier loop is deleted.

Table 12.5 gives the parametric points for which performance and energy costs were calculated, as well as the performance calculation results. (The calculated results are analyzed and shown graphically in Sections 12.4 and 12.6).

12.3 Approach

12.3.1 Atmospheric Furnace Systems

The thermodynamic cycle performance of the atmospheric pressure furnace steam plant was calculated by means of an existing computer code. Known as the Westinghouse Generalized Performance and Heat Balance Program, this complex code was developed over a number of years. It has the flexibility to do either very precise and detailed analyses based on existing Westinghouse turbine components or to use more approximate performance criteria in order to make broad parametric evaluations of the type done in this study. Typical assumptions normally utilized by the program for heater and feed pump performance are shown in Table 12.6. A typical example of the cycle configuration for which results were calculated is shown in Figure 12.5.

The Generalized Performance and Heat Balance Program calculates what is known as the "net turbine heat rate," which is the heat input to the steam divided by the power output of the generator. Boiler efficiency and plant auxiliaries are applied to the turbine heat rate to calculate the overall plant heat rate.

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TABLE 12.5 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (PRESSURIZED FLUIDIZED BED BOILER)

Sheet 1 of 3

Parametric Point	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
Power Output, MWe	696	557	421	708	568	430	710	570	431	703	562	422	705	566	430	722	582	443
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subbituminous Coal																		
Lignite Coal																		
Gas Turbine																		
Inlet Temp, °F	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1700	1700	1700	1700	1700	1700
Pressure Ratio	5	5	5	8	8	8	10	10	10	15	15	15	5	5	5	8	8	8
Air Equivalence Ratio (Nominal)	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8
Steam Turbine																		
Throttle Press, psia	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Throttle Temp, °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Temp, °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Condenser Press, in Hg Abs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Thermodynamic Eff, (1)																		
Powerplant Eff, %	37.2	37.3	37.5	37.5	37.6	37.9	37.5	37.6	37.9	37.3	37.2	37.3	37.5	37.6	37.9	37.9	38.1	38.5
Overall Eff, %	37.2	37.3	37.5	37.5	37.6	37.9	37.5	37.6	37.9	37.3	37.2	37.3	37.5	37.6	37.9	37.9	38.1	38.5
Total Capital Cost × 10^{-6}, $	316.6	262.8	216.1	304.1	254.9	210.3	300.3	252.4	208.4	293.4	247.9	205.1	319.7	266.1	217.8	309.5	259.1	214.3
Capital Costs, $/kWe	454.8	471.4	513.7	429.7	449.1	489.6	422.9	443.0	483.5	417.2	441.2	466.4	453.1	469.8	506.9	428.8	445.6	483.7
Cost of Elect, Mills/kWh																		
Capital	14.376	14.903	16.240	13.583	14.197	15.478	13.370	14.008	15.284	13.188	13.946	15.38	14.325	14.850	16.025	13.554	14.086	15.292
Fuel (2)	7.798	7.785	7.744	7.733	7.715	7.664	7.725	7.709	7.663	7.783	7.798	7.781	7.741	7.716	7.653	7.649	7.614	7.537
Oper. & Maint.	1.801	1.896	2.032	1.782	1.875	2.006	1.780	1.872	2.004	1.793	1.892	2.036	1.785	1.877	2.005	1.760	1.846	1.968
Total	23.98	24.59	26.02	23.10	23.79	25.15	22.88	23.59	24.95	22.76	23.63	25.19	23.85	24.44	25.68	22.96	23.55	24.80
Est. Time of Construction, yr	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6

Notes: (1) Where Applicable
(2) Use Base Delivered Fuel Cost

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TABLE 12.5 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (PRESSURIZED FLUIDIZED BED BOILER)

Sheet 2 of 3

Parametric Point	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36
Power Output, MWe	723	582	443	721	579	438	715	575	438	734	594	455	738	597	457	736	594	454
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Subbituminous Coal																		
Lignite Coal																		
Gas Turbine																		
Inlet Temp, °F	1700	1700	1700	1700	1700	1700	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800	1800
Pressure Ratio	10	10	10	15	15	15	5	5	5	8	8	8	10	10	10	15	15	15
Air Equivalence Ratio	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8
Steam Turbine																		
Throttle Press, psia	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500	3500
Throttle Temp, °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Reheat Temp, °F	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Condenser Press, in Hg Abs	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Thermodynamic Eff, ①																		
Powerplant Eff, %	37.9	38.1	38.4	37.8	37.8	38.1	37.7	37.9	38.3	38.3	38.5	39.1	38.3	38.6	39.1	38.2	38.4	38.7
Overall Eff, %	37.9	38.1	38.4	37.8	37.8	38.1	37.7	37.9	38.3	38.3	38.5	39.1	38.3	38.6	39.1	38.2	38.4	38.7
Total Capital Cost, $\times 10^{-6}$, $	302.9	254.9	208.[illegible]	297.7	251.6	208.9	323.1	268.1	220.7	311.6	261.8	217.3	309.0	261.1	217.0	304.3	258.5	213.0
Capital Costs, $/kWe	418.9	437.9	470.2	413.1	434.8	476.5	452.1	465.9	503.6	424.2	440.8	477.4	418.6	437.4	474.5	413.3	435.3	469.4
Cost of Elect, Mills/kWh																		
Capital	13.241	13.843	14.863	13.057	13.745	15.062	14.293	14.729	15.920	13.411	13.936	16.091	13.232	13.828	15.001	13.066	13.760	14.840
Fuel ②	7.651	7.620	7.648	7.682	7.666	7.623	7.686	7.650	7.569	7.578	7.528	7.428	7.566	7.519	7.424	7.596	7.561	7.487
Oper. & Maint.	1.759	1.847	1.969	1.766	1.857	1.987	1.770	1.858	1.979	1.740	1.822	1.934	1.736	1.817	1.931	1.742	1.825	1.845
Total	22.65	23.31	24.38	22.51	23.27	24.67	23.75	24.24	25.47	22.73	23.30	24.45	22.53	23.164	24.36	22.40	23.15	24.27
Est. Time of Construction, yr	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6	5.0	4.8	4.6

Notes: ① Where Applicable
② Use Base Delivered Fuel Cost

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TABLE 12.5 – ADVANCED STEAM PARAMETRIC POINT INVESTIGATION (PRESSURIZED FLUIDIZED BED BOILER)

Sheet 3 of 3

Parametric Point	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54
Power Output, MWe	726	585	442	665	534	403	777	621	466	823	656	490	710	570	431	709	569	430
Fuel																		
Bituminous Coal	X	X	X	X	X	X	X	X	X	X	X	X						
Subbituminous Coal													X	X	X			
Lignite Coal																X	X	X
Gas Turbine																		
Inlet Temp., °F	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600
Pressure Ratio	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Air Equivalence Ratio	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8	1.1	1.5	1.8
Steam Turbine																		
Throttle Press., psia	3500	3500	3500	3500	3500	3500	4500	4500	4500	5000	5000	5000	3500	3500	3500	3500	3500	3500
Throttle Temp., °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1400	1400	1400	1000	1000	1000	1000	1000	1000
Reheat Temp., °F	1000	1000	1000	1000	1000	1000	1200	1200	1200	1400	1400	1400	1000	1000	1000	1000	1000	1000
Condenser Press., in Hg Abs	2.0	2.0	2.0	9.0	9.0	9.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Thermodynamic Eff., ①																		
Powerplant Eff., %	38.4	38.6	38.8	35.2	35.3	35.4	40.9	40.8	40.8	42.8	42.7	42.6	39.0	39.1	39.3	38.1	38.2	38.4
Overall Eff., %	38.4	38.6	38.8	35.2	35.3	35.4	40.9	40.8	40.8	42.8	42.7	42.5	39.0	39.1	39.3	38.1	38.2	38.4
Total Capital Cost $\times 10^{-6}$, $	308.2	258.5	213.3	311.9	260.7	214.1	409.0	335.3	266.9	484.3	457.9	434.8	287.7	238.0	201.7	297.4	251.6	209.5
Capital Costs, $/kWe	424.2	441.8	482.3	468.7	488.1	530.7	526.4	540.2	572.7	588.8	698.3	887.4	404.9	417.5	467.7	419.3	442.1	486.7
Cost of Elect, Mills/kWh																		
Capital	13.410	13.966	15.245	14.818	15.431	16.777	16.641	17.077	18.104	18.613	22.074	28.064	12.800	13.199	14.784	13.250	13.975	15.387
Fuel ②	7.552	7.506	7.467	8.244	8.223	8.186	7.099	7.106	7.106	6.782	6.794	6.807	7.440	7.423	7.378	7.608	7.590	7.545
Oper. & Maint.	1.742	1.826	1.958	1.824	1.923	2.066	1.638	1.701	1.868	1.561	1.653	1.790	.879	.973	1.111	.914	1.009	1.146
Total	22.70	23.30	24.67	24.89	25.58	27.03	25.38	25.92	27.08	26.96	30.52	36.65	21.12	21.60	23.27	21.78	22.57	24.08
Est. Time of Construction, yr	5.0	4.8	4.6	5.0	4.8	4.5	5.1	4.9	4.6	5.1	4.9	4.7	5.0	4.8	4.6	5.0	4.8	4.6

Notes: ① Where Applicable
② Use Base Delivered Fuel Cost

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TABLE 12.6–TURBINE OPERATING PARAMETERS
SAMPLE AND TYPICAL ECAS ASSUMPTIONS

		Sample			Typical ECAS Assumptions		
Steam Conditions	Load	Pressure Drop	Heaters	Boiler Feed Pump	Pressure Drop	Heaters	Boiler Feed Pump
2400 psia 1000°F 1000°F Reheat	511100 kW @1.0 in Hg Abs 0% M. U.	Reheater 10% Throttle Valve 4%	Number 7 1 Open 4 with Drain Coolers DTD = 10°F TD = −3°F HTR #1 0°F HTR #2 5°F All Others $\Delta P/P = 5\%$	$\eta_P = 82\%$ $\eta_T = 80\%$ Excess Pressure = 16%	Reheater 10% Throttle Valve 4%	Number 7 1 Open 6 with Drain Coolers DTD = 10°F TD = 5°F $\Delta P/P = 5\%$	$\eta_P = 82\%$ $\eta_T = 80\%$ Excess Pressure = 25% At Valves Wide Open
3500 psia 1000°F 1000°F	584536 kW @1.0 in Hg Abs 0% M. U.	Reheater 10% Throttle Valve 4%	Number 8 1 Open 7 with Drain Coolers DTD = 10°F TD = −2°F HTR #1 2°F HTR #2 −3°F HTR #3 5°F All Others $\Delta P/P = 5\%$	$\eta_P = 84.8\%$ $\eta_P = 80.8\%$ Excess Pressure = 18%	Reheater 10% Throttle Valve 4%	Number 8 1 Open 7 Closed DTD = 10°F TD = 5°F $\Delta P/P = 5\%$	$\eta_P = 82\%$ $\eta_P = 80\%$ Excess Pressure = 25% At Valves Wide Open

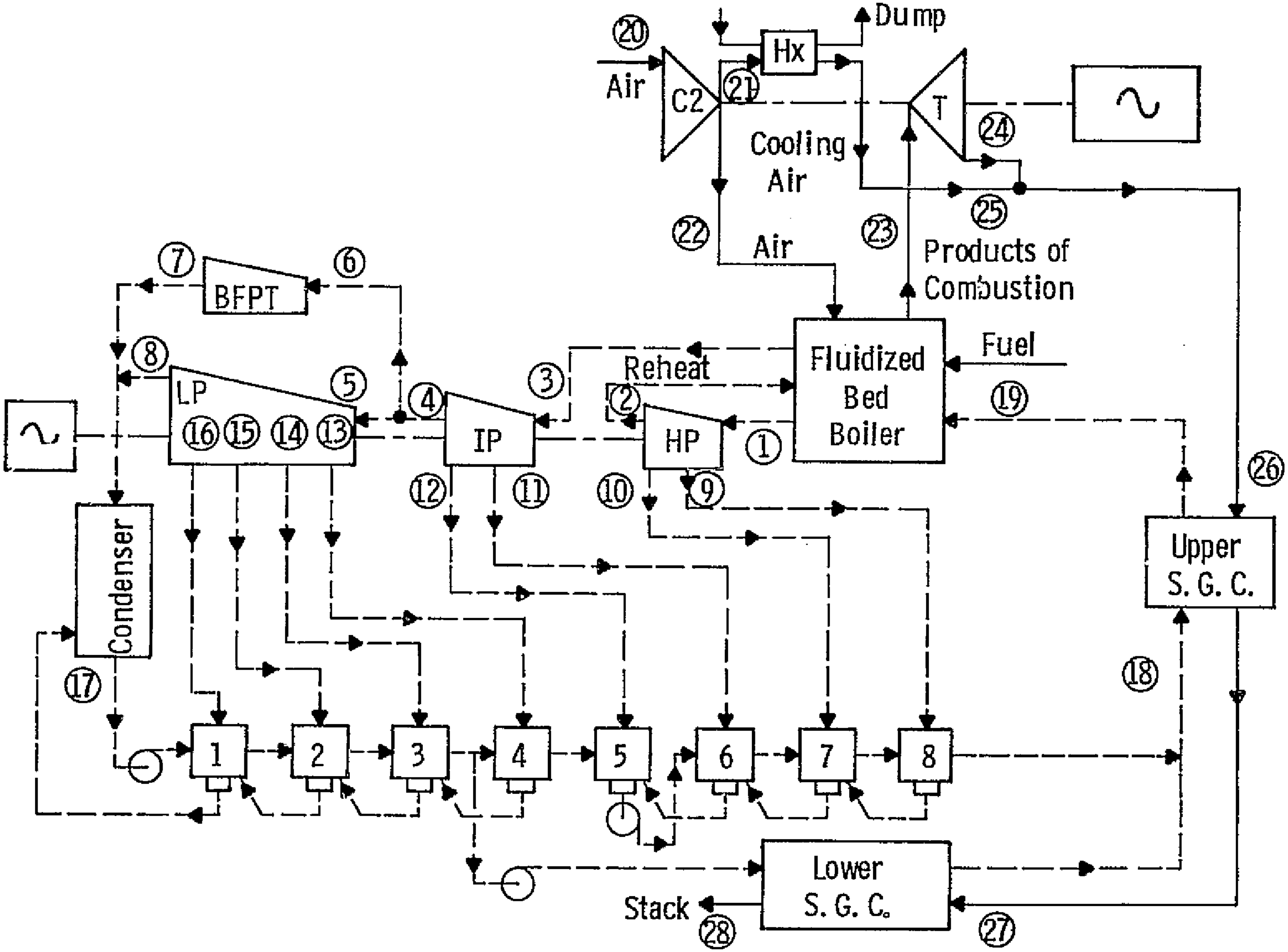

Fig. 12.7—Schematic of pressurized fluidized bed boiler power plant

12.3.2 Pressurized Boiler-Gasifier System

In a steam power plant with a pressurized boiler, the performance of the plant depends in part upon the performance of the pressurizing gas turbine. As can be seen in Figure 12.6, the cycle consists essentially of a gas turbine power plant and a steam turbine power plant operating nominally in parallel and utilizing interacting heat exchangers. These heat exchangers are a pressurized steam boiler, an upper stack-gas cooler, and a lower stack-gas cooler. The boiler, of course, boils and superheats the feedwater. The upper and lower stack-gas coolers recuperate heat from the hot exhaust gases of the gas turbine and transfer it to the feedwater stream.

This cycle incorporates an integrated coal gasifier which uses pressurized air and steam (process fluids) from the gas and steam turbines. Because of the substantial pressure drop in the gasifier it is necessary to provide an auxiliary compressor to raise the pressure of the process air.

A previously developed Westinghouse computer code was modified to incorporate the performance variations of the coal gasifier which are a function of the process air temperature and, therefore, the cycle pressure ratio. With appropriate component performance characteristics incorporated into the code, the cycle calculation proceeds to determine the state point of the working fluids throughout the cycle and solves ten mass and heat balance equations simultaneously to determine the steam extraction flow rates. This system is solved iteratively to determine the combination of fuel input and steam flow rate which results from the assumed values of steam and gas turbine inlet temperature.

12.3.3 Pressurized Fluidized Bed Boiler System

As shown in Figure 12.7, this cycle is similar to but slightly simpler than the previous system because the gasifier is eliminated. The same basic computer code applies and was used without the gasifier modification but with an appropriate pressure drop associated with the fluidized bed combustion process.

Table 12.7 - Advanced Steam Conventional Atmospheric Furnace (Parametric Point 20)

Location	$M_{STM} \times 10^{-6}$, lb/hr	T, °F or (1-x)*	P, psia
1	3.515412	1000	3515
2	3.096373	570	667
3	3.096373	1000	600
4	2.989328	648	143
5	2.654888	648	143
6	0.215946	647	136
7	0.215946	125	1.96
8	2.184833	8.3%	1.72
9	0.348643	565	633
10	0.155059	825	284
11	0.130405	647	136
12	0.167026	529	75
13	0.098205	346	28
14	0.126278	235	14
15	0.083817	162	5
16	2.184833	91.7	1.72
17	3.515373	492	4390

* 1-x = % moisture
x = quality

12.4 Performance Results of the Parametric Study

12.4.1 Atmospheric Furnace Systems

Table 12.7 lists the flow rates and state points of the steam working fluid for the base case throughout the cycle as defined in Figure 12.5. The base case is a nominal 500 MWe steam plant with a 24.134 MPa (3500 psi) throttle pressure, an 811°K (1000°F) throttle temperature, a single reheat to 811°K (1000°F), and a condenser pressure of 11.819 kPa (3.5 in Hg)abs.

Figure 12.8 shows the increase in overall energy efficiency that results when the steam temperature and pressure are increased. As can be seen, increasing the steam temperature from 811 to 1033°K (1000°F to 1400°F) increases the efficiency from $\sim$35% to 39%, and the benefit of high pressure increases with increasing temperature.

The efficiency for the 16.547 MPa (2400 psi) pressure level at 1033°K (1400°F) is shown for a case without reheat. This is because at this elevated throttle temperature the use of reheat would result in superheated steam in the turbine low-pressure end at the design operating point. The superheated steam in the low pressure end presents a serious materials problem since the blading and rotor is subjected to excessive temperature when the turbine operates at off-design conditions.

Figure 12.9 shows a comparison between the overall energy efficiency of a power plant with a conventional boiler and one with a fluidized bed boiler. The efficiencies of the power plants, both at a 24.132 and 34.472 MPa (3500 and a 5000 psi) throttle pressure, are plotted against throttle steam temperature. As would be expected, the furnace type has negligible effect on the slope of efficiency versus temperature, but the fluidized bed system results in a slightly lower efficiency at a given temperature level. This is primarily due to the lower boiler efficiency of the fluidized furnace which results from the in-bed desulfurization reaction loss.

Curve 682216-A

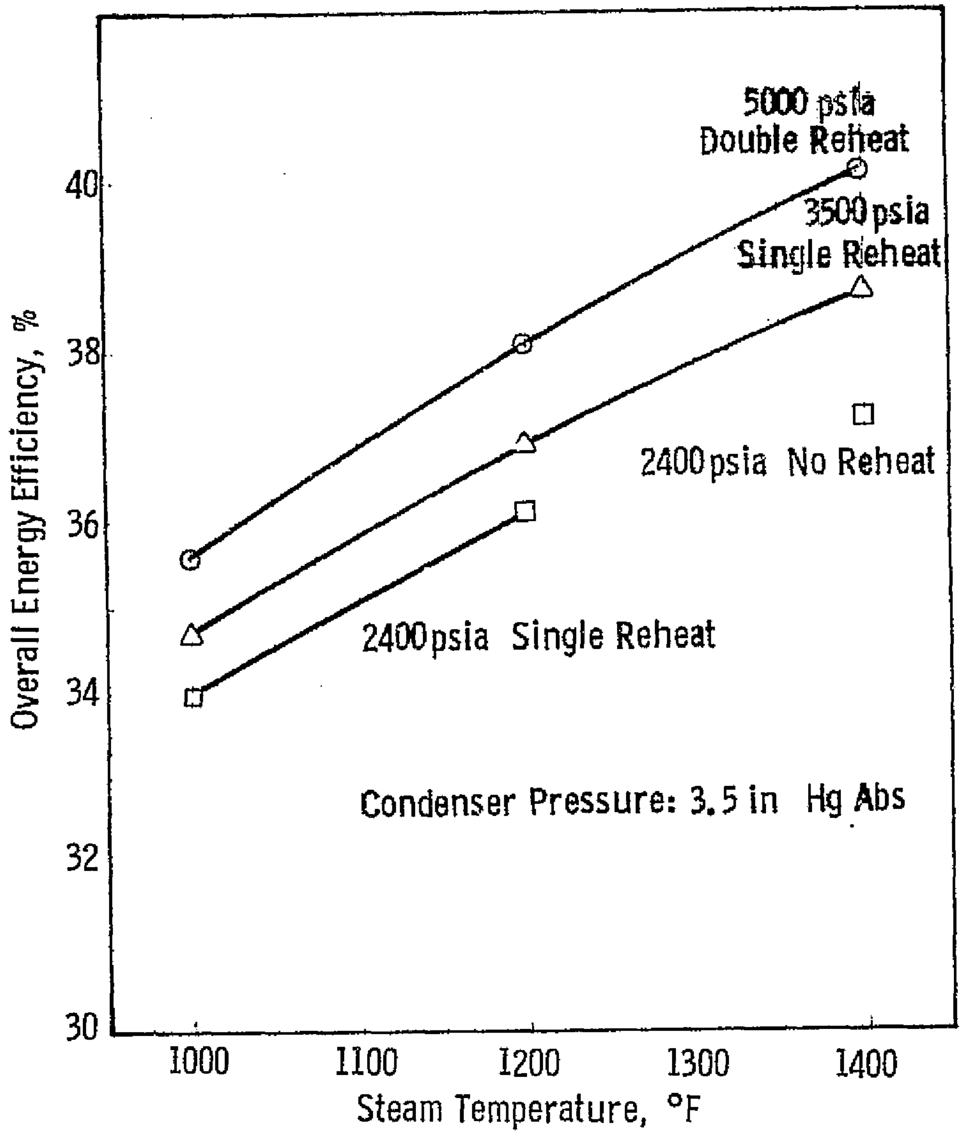

Fig. 12.8—Effect of steam turbine throttle temperature on overall effeciency for a 500 MWe steam plant with an atmospheric furnace

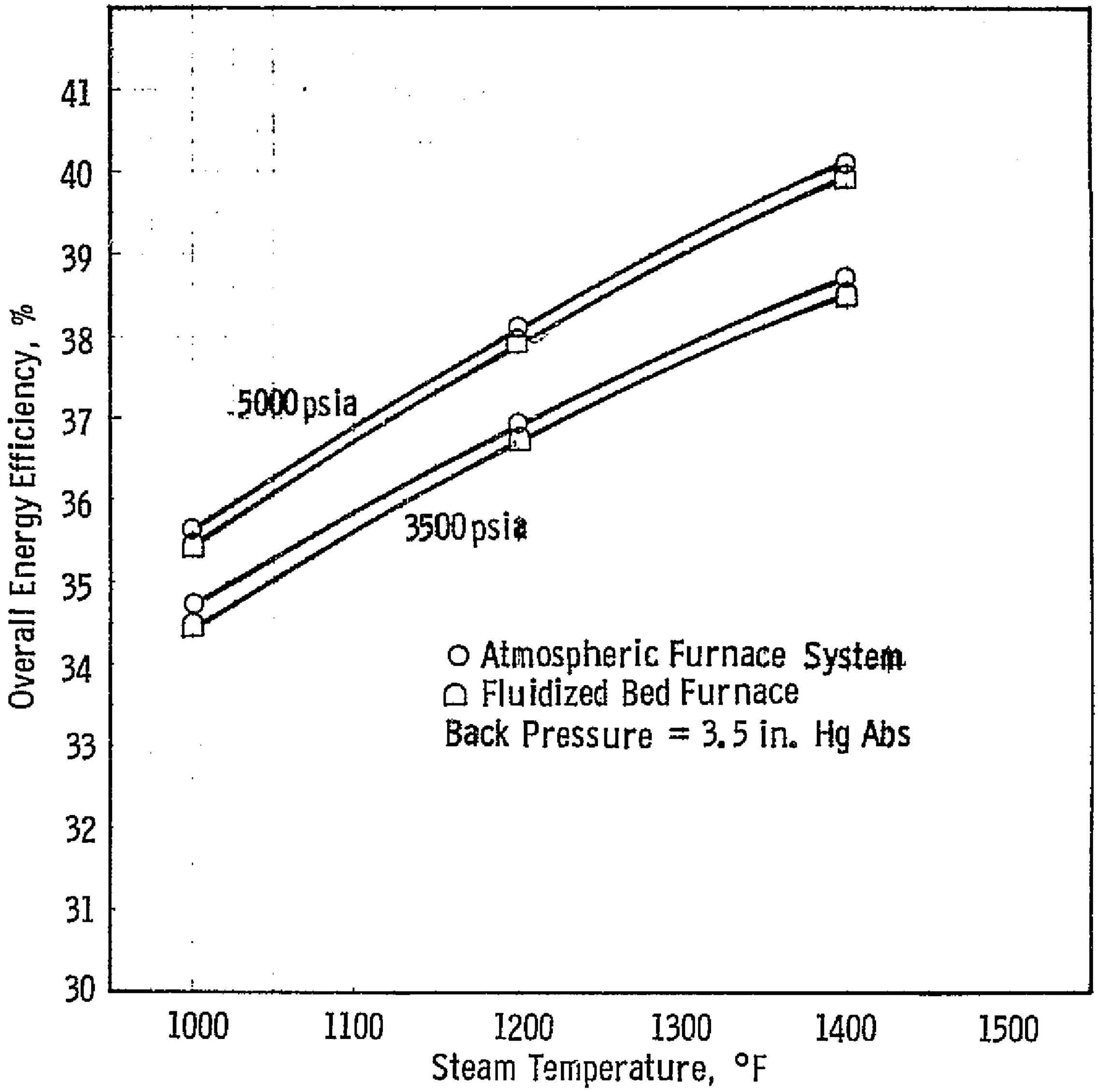

Fig. 12.9—Effect of temperature on overall efficiency for a 500 MWe steam plant with an atmospheric furnace

Curve 682220-A

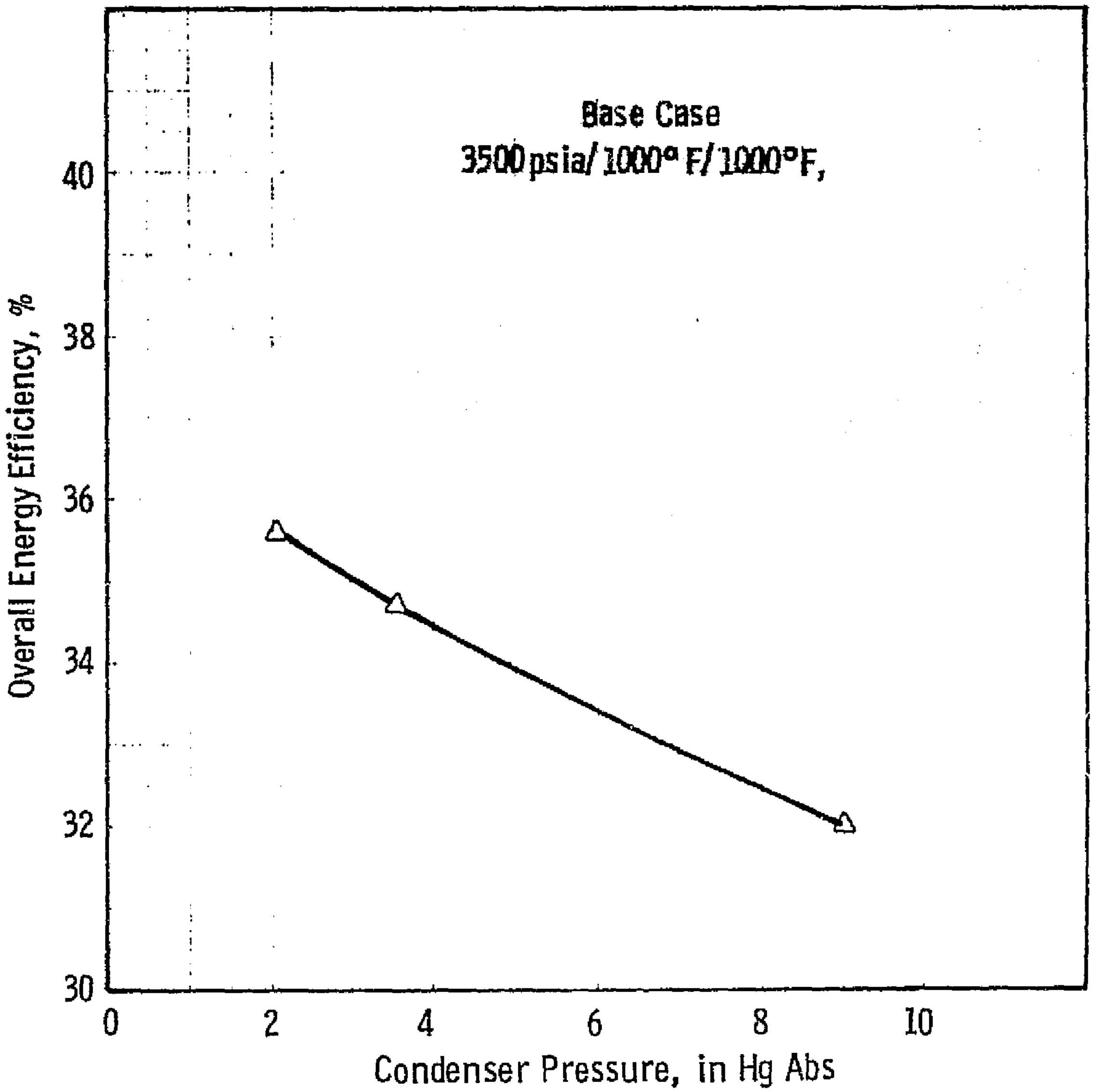

Fig. 12.10—Effect of condenser pressure on overall efficiency for a 500 MWe steam plant with an atmospheric furnace

The variation of overall energy efficiency as a function of condenser pressure is shown in Figure 12.10. As would be expected in a steam plant, reducing the condenser pressure results in a significant improvement in plant efficiency.

The effect of increasing the size of the plant from a nominal level of 500 to 900 MWe is small (see Figure 12.11). The slight improvement in energy efficiency is the result of a small improvement in turbine efficiency.

Figure 12.12 illustrates the effect of type of coal burned on the overall energy efficiency. The slight improvement caused by changing from Illinois No. 6 bituminous to Montana subbituminous coal is due to the sulfur content of the Montana coal, which allows a lower air preheater exit temperature [400°K (260°F) instead of 428°K (310°F)], thus reducing sensible heat loss. This improvement is slightly greater than the higher latent heat loss due to the greater moisture content in the Montana coal. The North Dakota lignite, however, has an even greater moisture content, which overcomes the sensible heat gain and results in a decrease in overall efficiency.

Finally, Figure 12.13 illustrates the effect of various combinations of throttle and reheat temperature. The points are located on the abscissa at the temperature level defined by a simple average of the throttle and reheat temperatures. The significant variations from the trend of similar throttle and reheat temperatures result more from the number of reheats than from the average temperature for a given number of reheats.

12.4.2 Pressurized Boiler-Gasifier System

Table 12.8 lists the flow rates and state points of the steam and gas working fluids for the base case throughout the cycle illustrated in Figure 12.6. For the base case, the steam bottomer has a 24.134 MPa (3500 psi) throttle pressure, an 811°K (1000°F) throttle temperature, a single reheat to 811°K (1000°F), and a condenser pressure of 11.819 kPa (3.5 in Hg)abs. The gas turbine engine has a pressure ratio of 10:1 and

Curve 682217-A

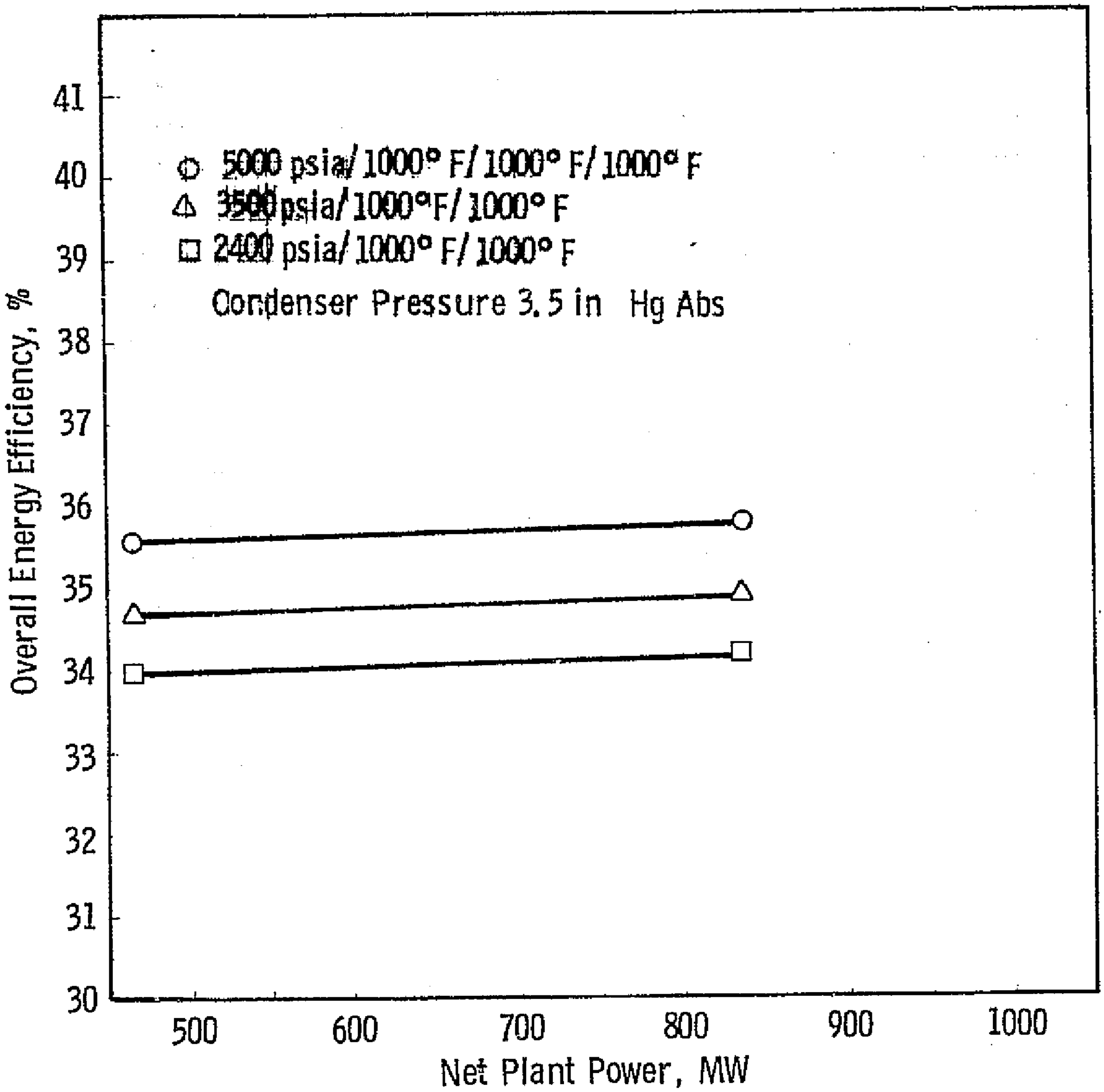

Fig. 12.11—Effect of plant size on overall efficiency for a steam plant with an atmospheric furnace

Curve 682223-A

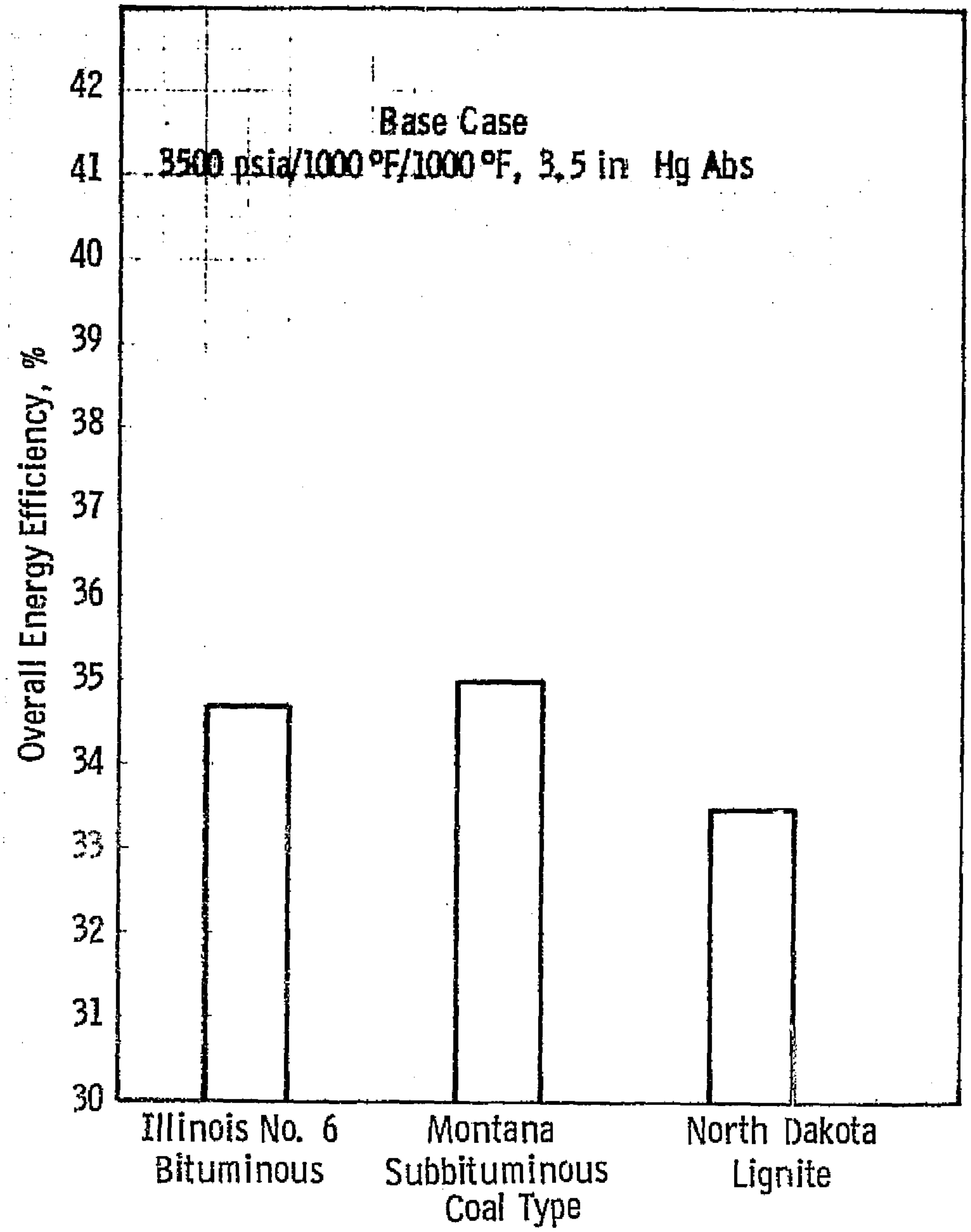

Fig. 12.12—Effect of coal type on overall efficiency for a 500 MWe steam plant with an atmospheric furnace

Curve 682219-A

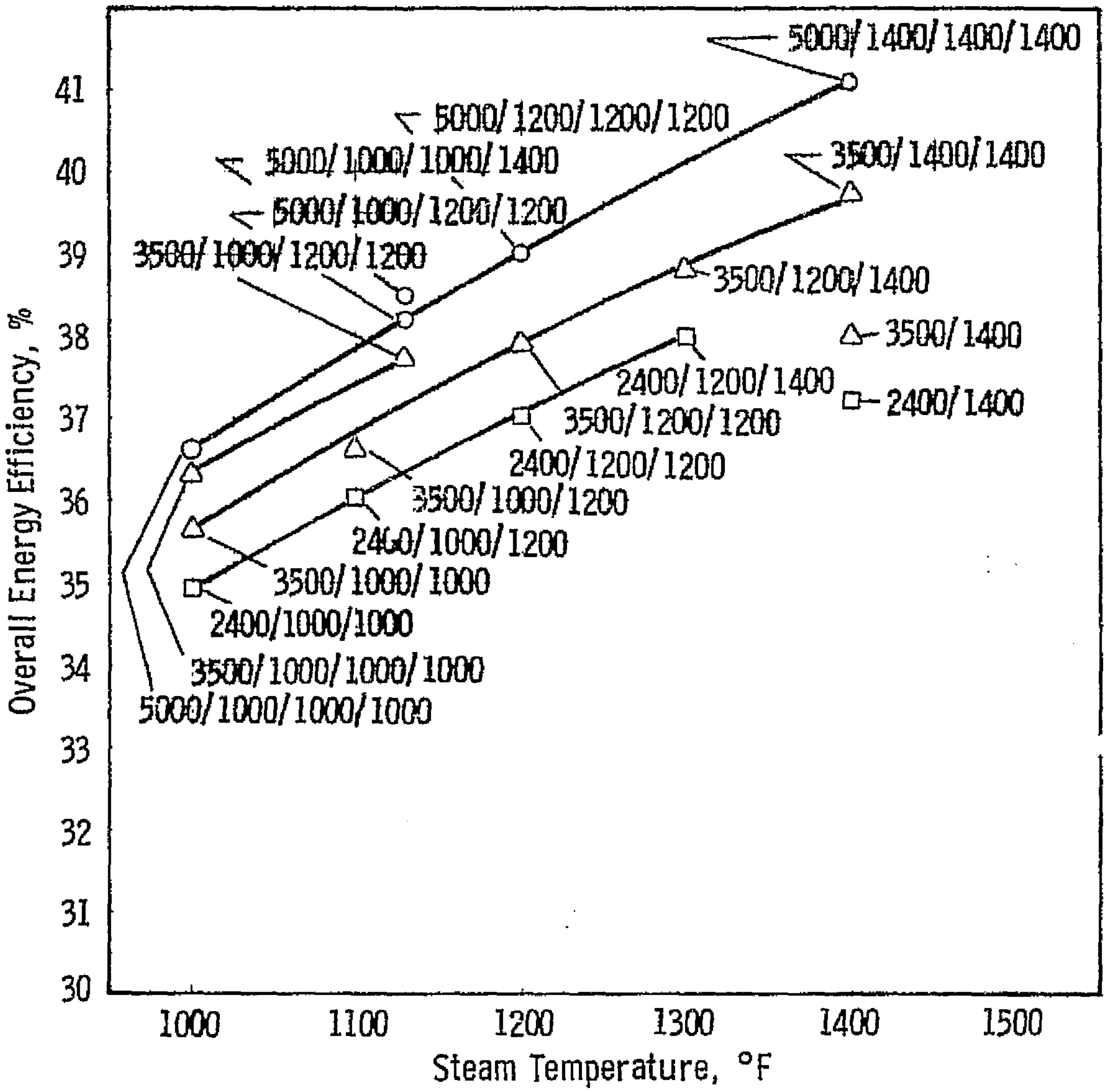

Fig. 12.13—Effect of steam throttle conditions on overall efficiency for a 500 MWe steam plant with an atmospheric furnace

Table 12.8 - Advanced Steam Pressurized Boiler-Gasifier System (Parametric Point 16)

Location	Flow Rate of Steam X 10^{-3}, lb/hr	T, °F or (1-x)*	P, psia	Flow Rate Gas, lb/s
1	3954.6	1000	3550	--
2	3671.3	557	608	--
3	3671.3	1000	534	--
4	3471.7	617	121	--
5	3265.4	617	121	--
6	206.3	617	121	--
7	206.3	4.9%	1.7	--
8	2877.2	7.5%	1.7	--
9	139.9	650	925	--
10	143.5	557	608	--
11	106.9	843	304	--
12	92.7	617	121	--
13	64.2	434	47.9	--
14	61.0	341	28.1	--
15	145.8	240	15.0	--
16	117.1	3.4%	5.2	--
17	3083.5	117	1.7	--
18	3954.6	530	∿ 4000	--
19	3954.6	608	∿ 4000	--
20	--	59	14.7	1520
21	--	663.8	145.9	147.4
22	--	663.8	145.9	970.8
23	--	2000	137.1	1613.4
24	--	1155.3	15.3	1613.4
25	--	470	145.9	147.4
26	--	1112.4	15.3	1721.9
27	--	600.6	15.0	1721.9
28	--	275	14.7	1721.9

* 1-x = % moisture
x = quality

Curve 682203-A

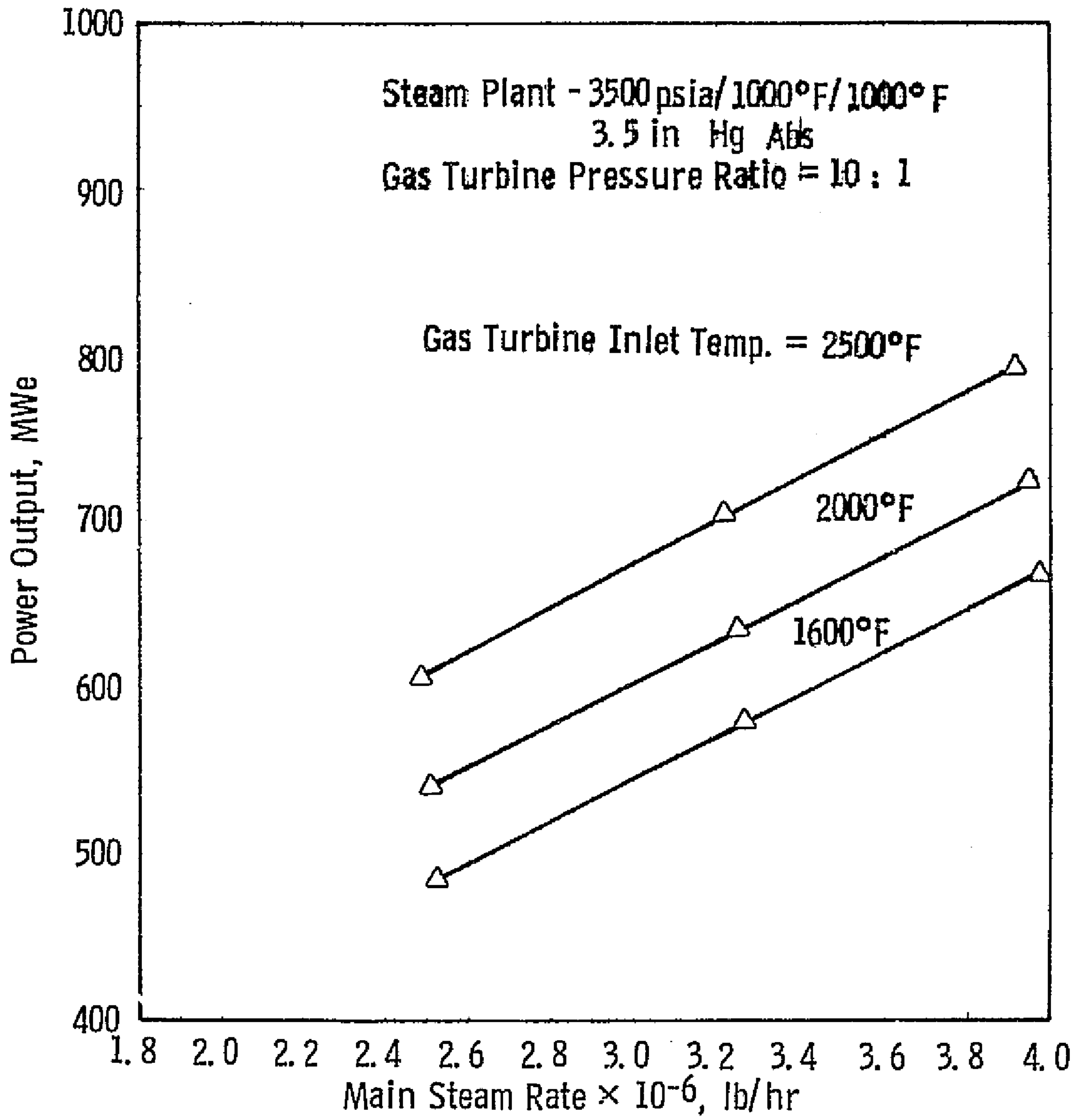

Fig. 12.14—Effect of steam flow rate on plant power and output for a nominal 600 MWe steam plant with a pressurized boiler gasifier system

a turbine inlet temperature of 1367°K (2000°F). The steam bottomer has a nominal power of 550 MWe, and the gas turbine engines have a nominal power of 200 MWe.

For a fixed airflow rate of 689.5 kg/s (1520 lb/s) (specified by the use of two W501 gas turbines for all parametric points), the steam flow rate is determined by the rate of fuel burned in the boiler. This is limited, however, by the fact that the sum of the fuel burned in the boiler and gas turbine combustor must not exceed the stochiometric value. The plant power level increases, of course, as the steam flow increases, as shown in Figure 12.14. Figures 12.15, 12.16, and 12.17 give the overall energy efficiency versus the main steam flow rate with parameters of gas turbine temperature and pressure ratio. It can be seen from these figures that the efficiency is not very sensitive to steam flow rate, that it increases substantially with gas turbine temperature, and that it nears a maximum at a pressure ratio of 10:1. Figure 12.18, which is a cross-plot of the previous three figures, shows clearly the beneficial effect of increasing the gas turbine inlet temperature.

Because the bulk of the power comes from the steam bottomer, the condenser pressure has a significant effect on efficiency, as shown in Figure 12.19.

The variation in the combination of sulfur and moisture content among the fuels results in the variation in efficiency shown in Figure 12.20.

Finally, Figure 12.21 shows that a substantial increase in efficiency will result from an increase in steam temperature and pressure.

12.4.3 Pressurized Boiler Fluidized Bed Boiler System

Table 12.9 lists the flow rates and state points of the steam and gas working fluids for the base case throughout the cycle illustrated in Figure 12.7. For the base case, the steam bottomer has a 24.134 MPa (3500 psi) throttle pressure, an 811°K (1000°F) throttle temperature, a single reheat to 811°K (1000°F), and a condenser pressure of 11.819 kPa

Curve 682197-A

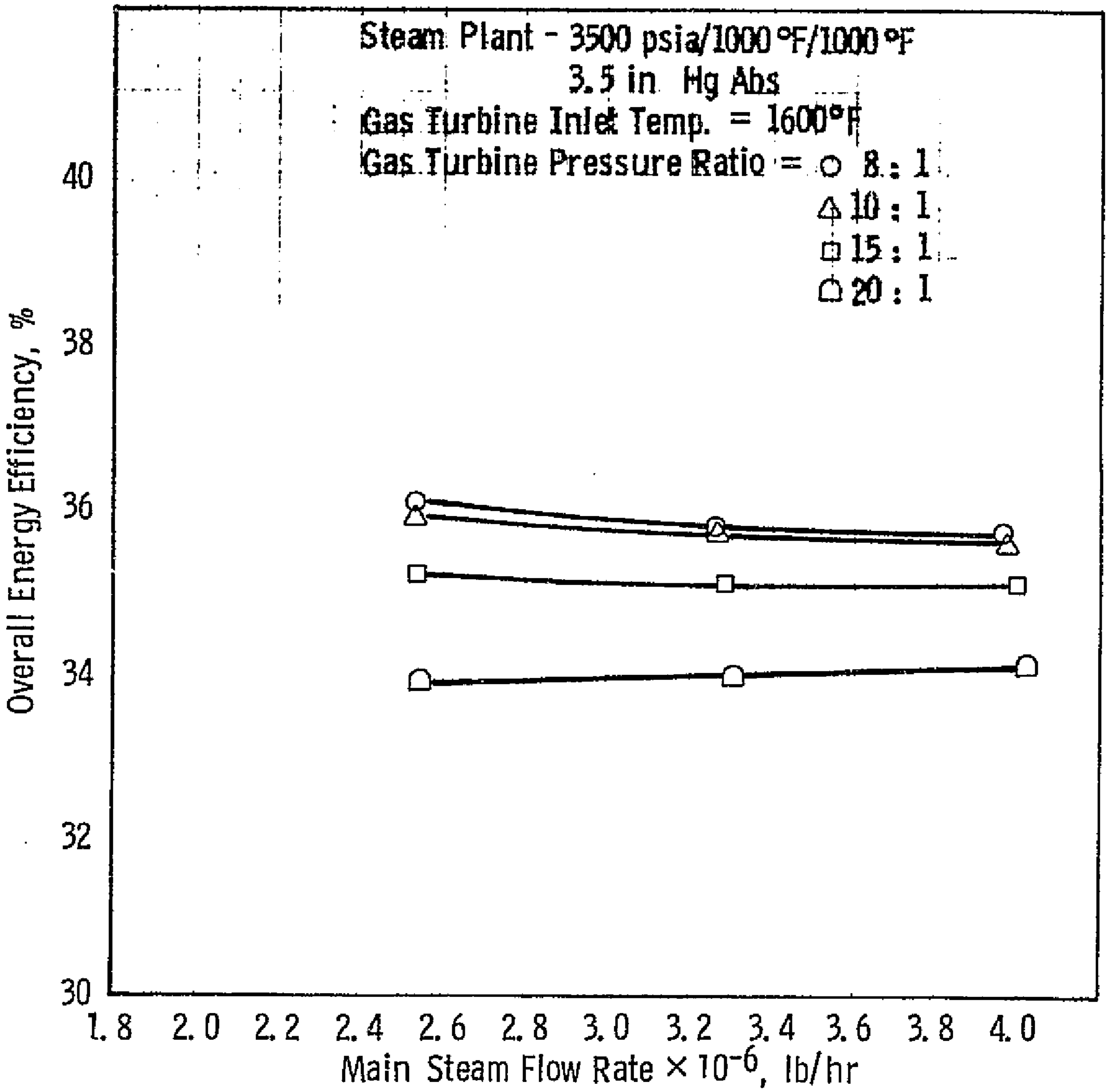

Fig. 12.15—Effect of steam flow and pressurizing gas turbine pressure ratio on overall efficiency for a nominal 600 MWe steam plant with a pressurized boiler gasifier system

Curve 682210-A

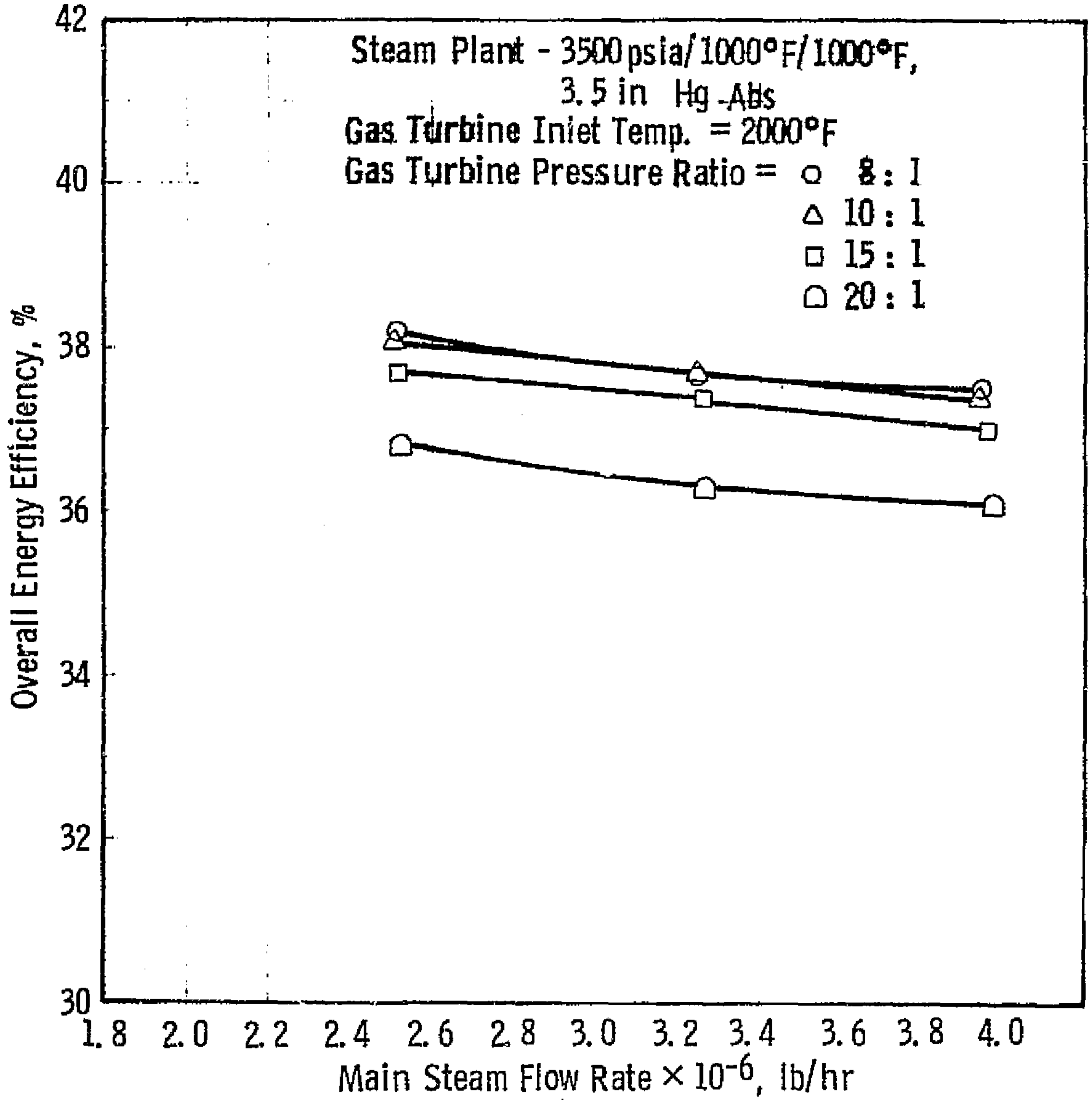

Fig. 12.16—Effect of steam flow rate and pressurizing gas turbine pressure ratio on overall efficiency for a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Curve 682194-A

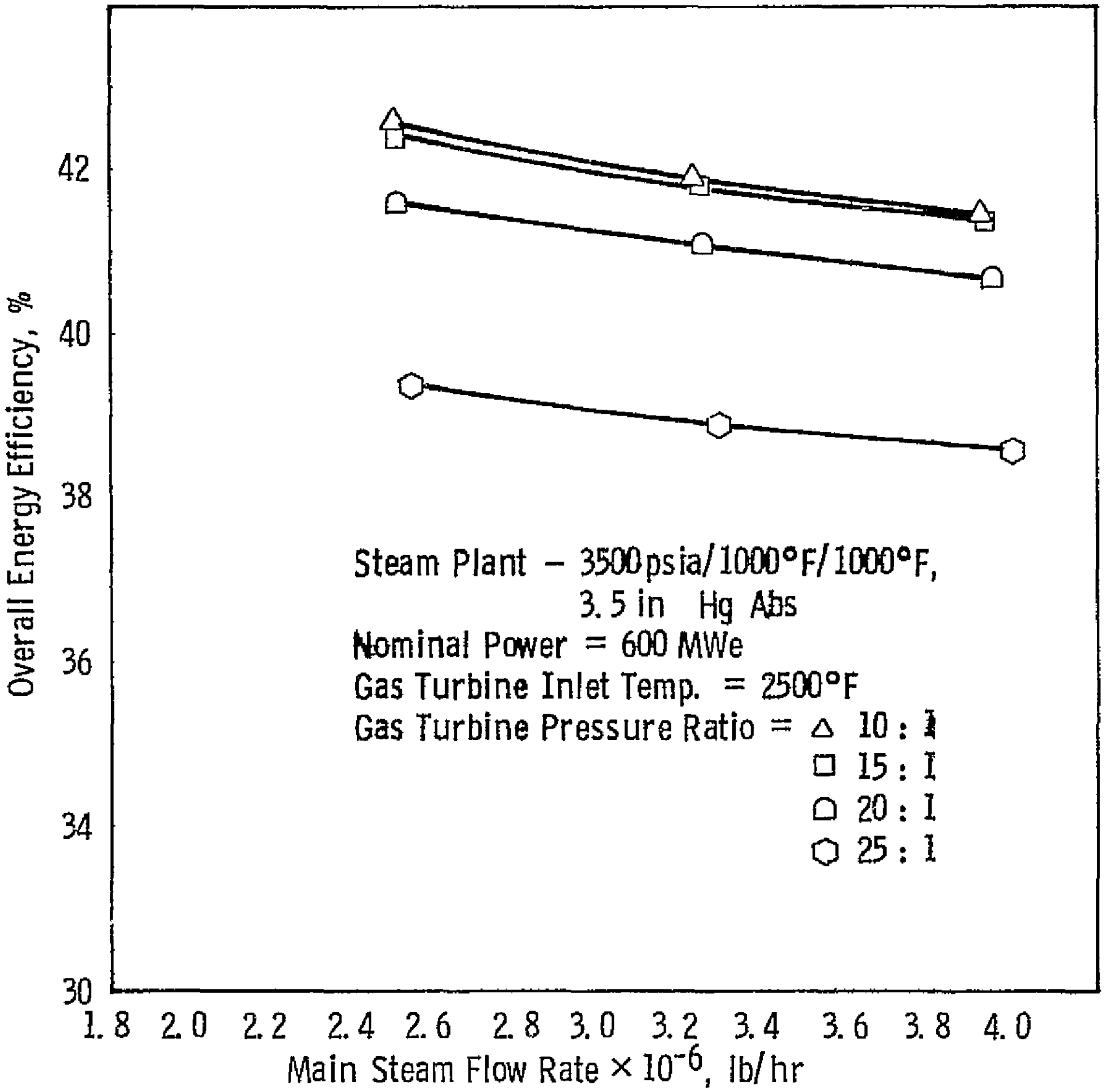

Fig. 12.17—Effect of steam flow rate and pressurizing gas turbine pressure ratio on overall efficiency for a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

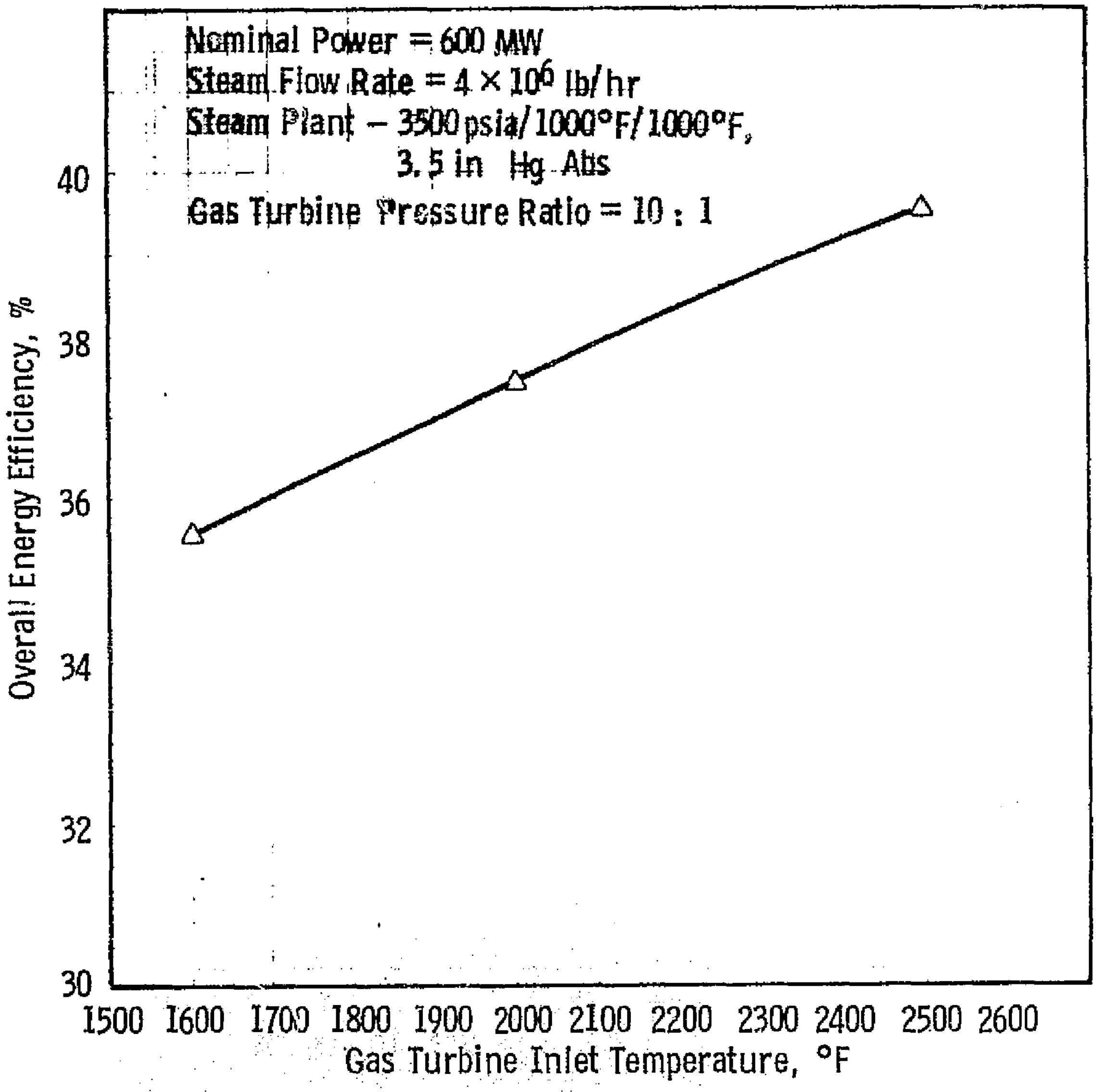

Fig. 12.18—Effect of pressurizing gas turbine inlet temperature on overall efficiency for a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Curve 682204-A

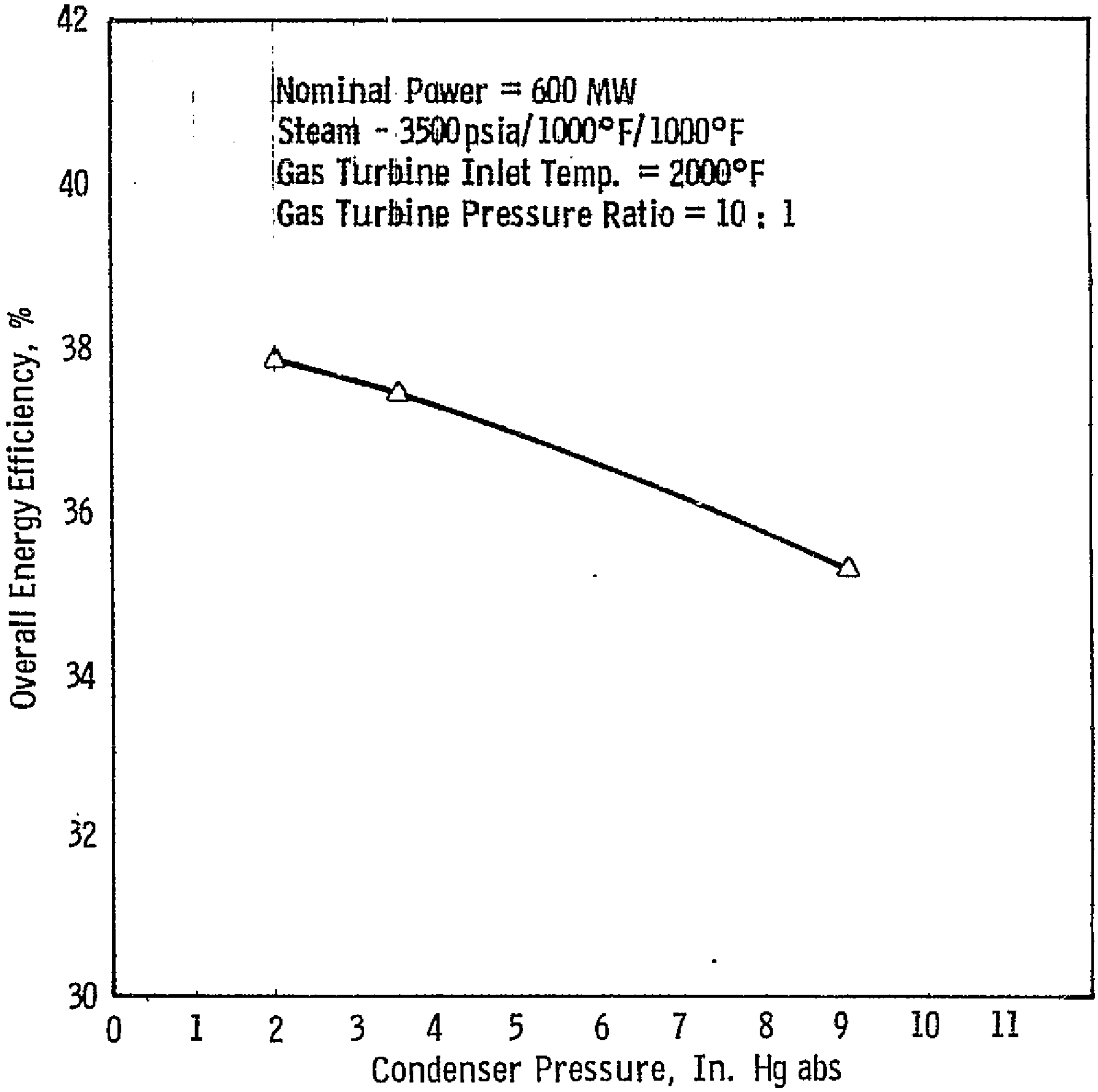

Fig. 12.19—Effect of condenser pressure on overall efficiency for a steam plant with a nominal 600 MWe pressurized boiler gasified system

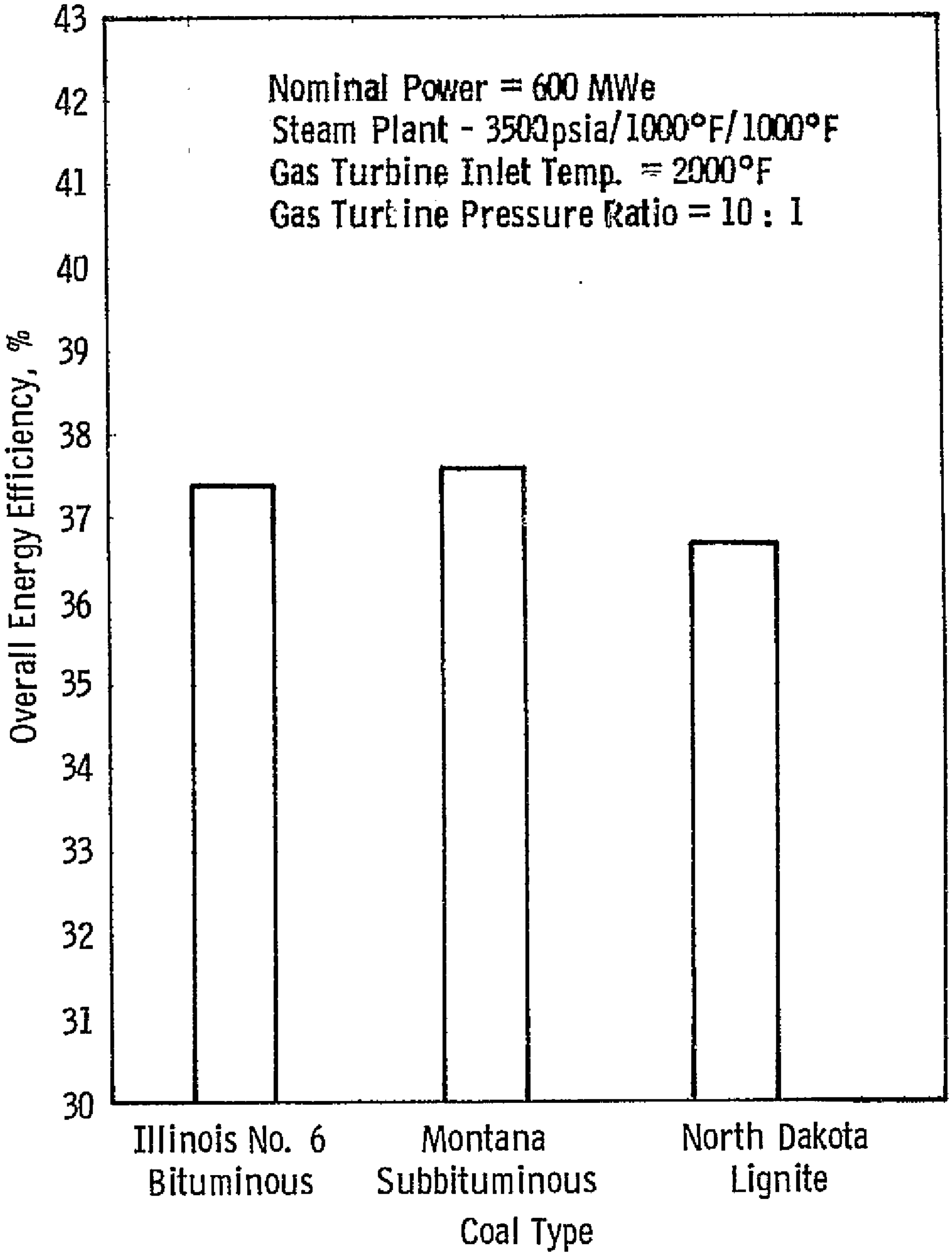

Fig. 12.20—Effect of coal type on overall efficiency for a nominal 600 MWe steam plant with a pressurized boiler gasifier system

Curve 682215-A

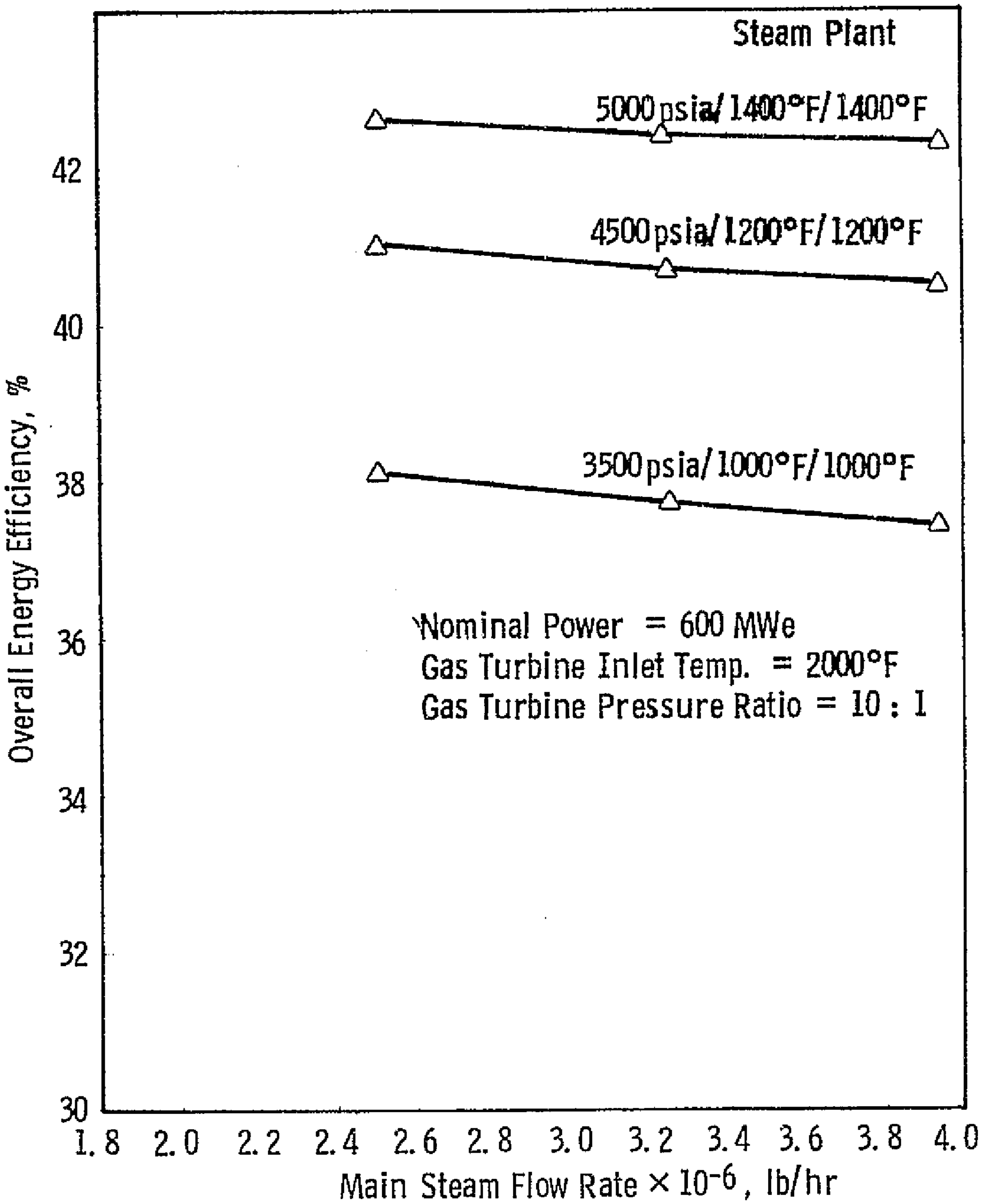

Fig. 12.21—Effect of steam flow rate and steam turbine throttle conditions on overall efficiency for a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Table 12.9 - Advanced Steam Pressurized Fluidized Bed Boiler Base Case (Parametric Point 7)

Location	Flow Rate of Steam X 10^{-3}, lb/hr	T, °F or (1-x)*	P, psia	Flow Rate Gas, lb/s
1	4000.0	1000	3500	--
2	3639.8	557	608	--
3	3639.8	1000	534	--
4	3386.0	617	121	--
5	3166.1	617	121	--
6	219.9	617	121	--
7	2.919	4.9%	1.7	--
8	2742.7	7.5%	1.7	--
9	177.8	650	925	--
10	182.4	557	608	--
11	135.9	843	304	--
12	117.9	617	121	--
13	81.6	434	47.9	--
14	64.4	341	28.1	--
15	153.8	240	15.0	--
16	123.6	3.4%	5.2	--
17	2962.6	117	1.7	--
18	4000.0	530	≃ 4000	--
19	4000.0	608	≃ 4000	--
20	--	59	14.7	1520
21	--	595.8	145.9	92.7
22	--	595.8	145.9	1427.3
23	--	1600	134.2	1563.2
24	--	866.6	15.3	1563.2
25	--	470	145.9	92.7
26	--	844.4	15.3	1655.9
27	--	584	15.0	1655.9
28	--	275	14.7	1655.9

* 1-x = % moisture
  x = quality

Table 12.10 - Advanced Steam Pressurized Fluidized Bed Boiler - Preferred Case (Parametric Point 31)

Location	Flow Rate of Steam X 10^{-3}, lb/hr	T, °F or (1-x)*	P, psia	Flow Rate Gas, lb/s
1	4000.0	1000	3500	--
2	3640.4	557	608	--
3	3640.4	1000	534	--
4	3387.0	617	121	--
5	3167.1	617	121	--
6	219.9	617	121	--
7	219.9	4.9%	1.7	--
8	2743.5	7.5%	1.7	--
9	177.5	650	925	--
10	182.1	557	608	--
11	135.7	843	304	--
12	117.7	617	121	--
13	81.5	434	49.9	--
14	64.5	341	28.1	--
15	153.9	240	15.0	--
16	123.7	3.4%	5.2	--
17	2963.4	117	1.7	--
18	4000.0	530	≈ 4000	--
19	4000.0	642	≈ 4000	--
20	--	59	14.7	1520
21	--	595.8	145.9	120.1
22	--	595.8	145.9	1399.9
23	--	1800	134.2	1538.3
24	--	1008.9	15.3	1538.3
25	--	470	145.9	120.1
26	--	970.4	15.3	1658.4
27	--	584	15.0	1658.4
28	--	275	14.7	1658.4

* 1-x = % moisture
x = quality

(3.5 in Hg) abs. The gas turbine engine has a pressure ratio of 10:1 and a turbine inlet temperature of 1144°K (1600°F). The steam bottomer has a nominal power of 600 MWe, and the gas turbine engines have a nominal power of 120 MWe.

Table 12.10 is a similar listing of conditions for the preferred case, which is very similar to the base case except that the gas turbine inlet temperature is increased to 1253°K (1800°F).

For a fixed airflow rate of 689.5 kg/s (1520 lb/s) (specified by the use of two W501 gas turbines for all parametric points) the steam flow rate is determined by the boiler coal consumption rate. This is limited, however, by the fact that the amount of coal burned must not exceed the stochiometric value. The plant power level increases, of course, as the steam flow rate increases (see Figure 12.22). Figures 12.23, 12.24, and 12.25 show the overall energy efficiency versus the main steam flow rate with parameters of gas turbine temperature and pressure ratio. It can be seen from these figures that the efficiency is not very sensitive to steam flow rate, that it increases substantially with gas turbine temperature, and that it nears a peak at a pressure ratio of 10:1. Figure 12.26, which is a cross-plot of the previous three figures, shows clearly the beneficial effect of increasing the gas turbine temperature. It should be noted, however, that the maximum temperature shown is 1253°K (1800°F). This is because the maximum temperature in the bed is limited by the in-bed desulfurization reaction. Further, without substantial additional equipment to produce a gaseous fuel it is not possible to increase the gas turbine inlet temperature by means of a reheat combustor.

Figure 12.27 shows that a significant improvement in efficiency results from a reduction in condenser pressure. This is because the major portion of the system power is produced by the steam bottomer.

The variation in the combination of sulfur and moisture content among the fuels results in the variation in efficiency shown in Figure 12.28.

Curve 682200-A

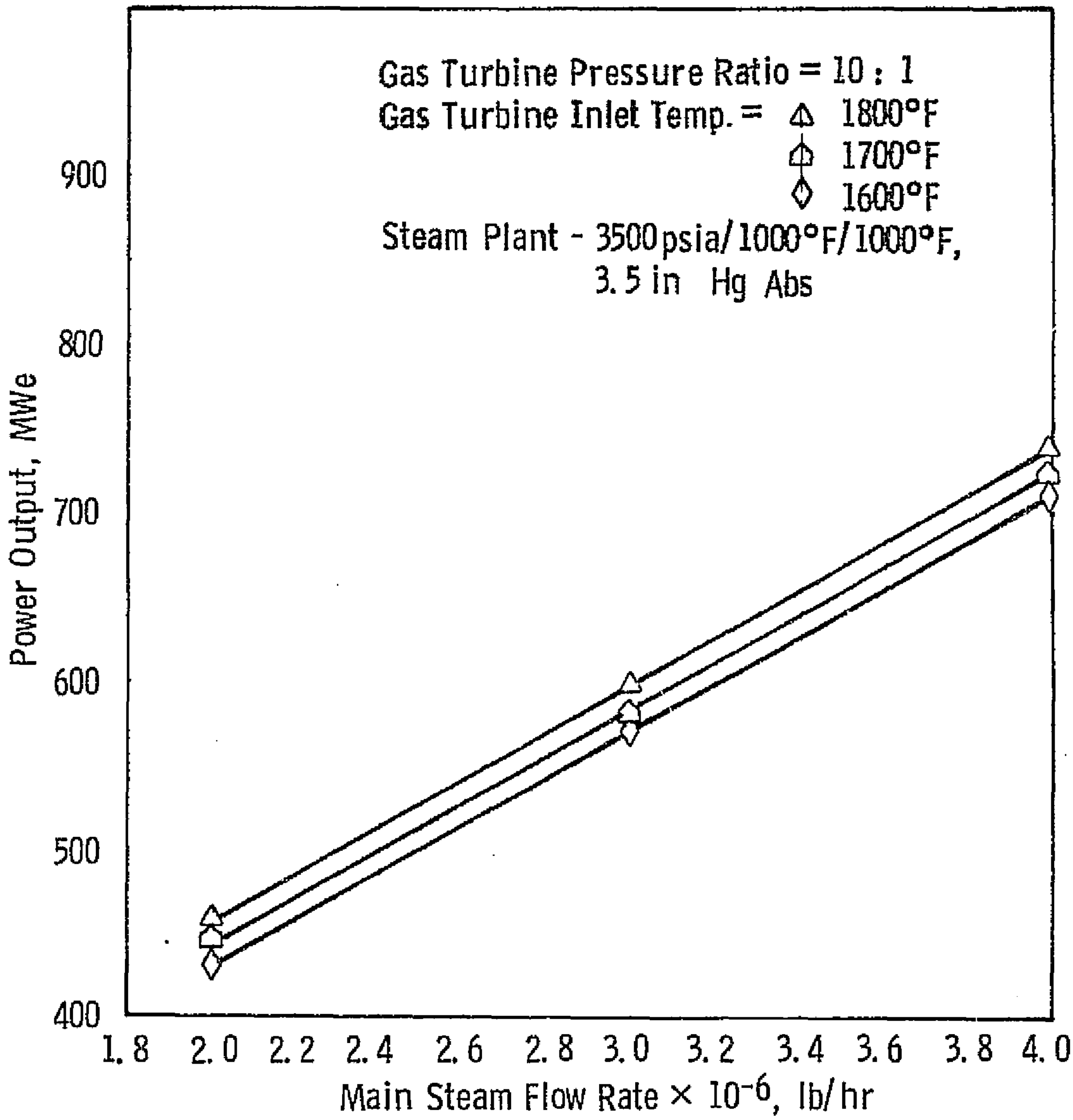

Fig. 12.22—Effect of steam flow rate and pressurizing gas turbine inlet temperature on plant power output for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682196-A

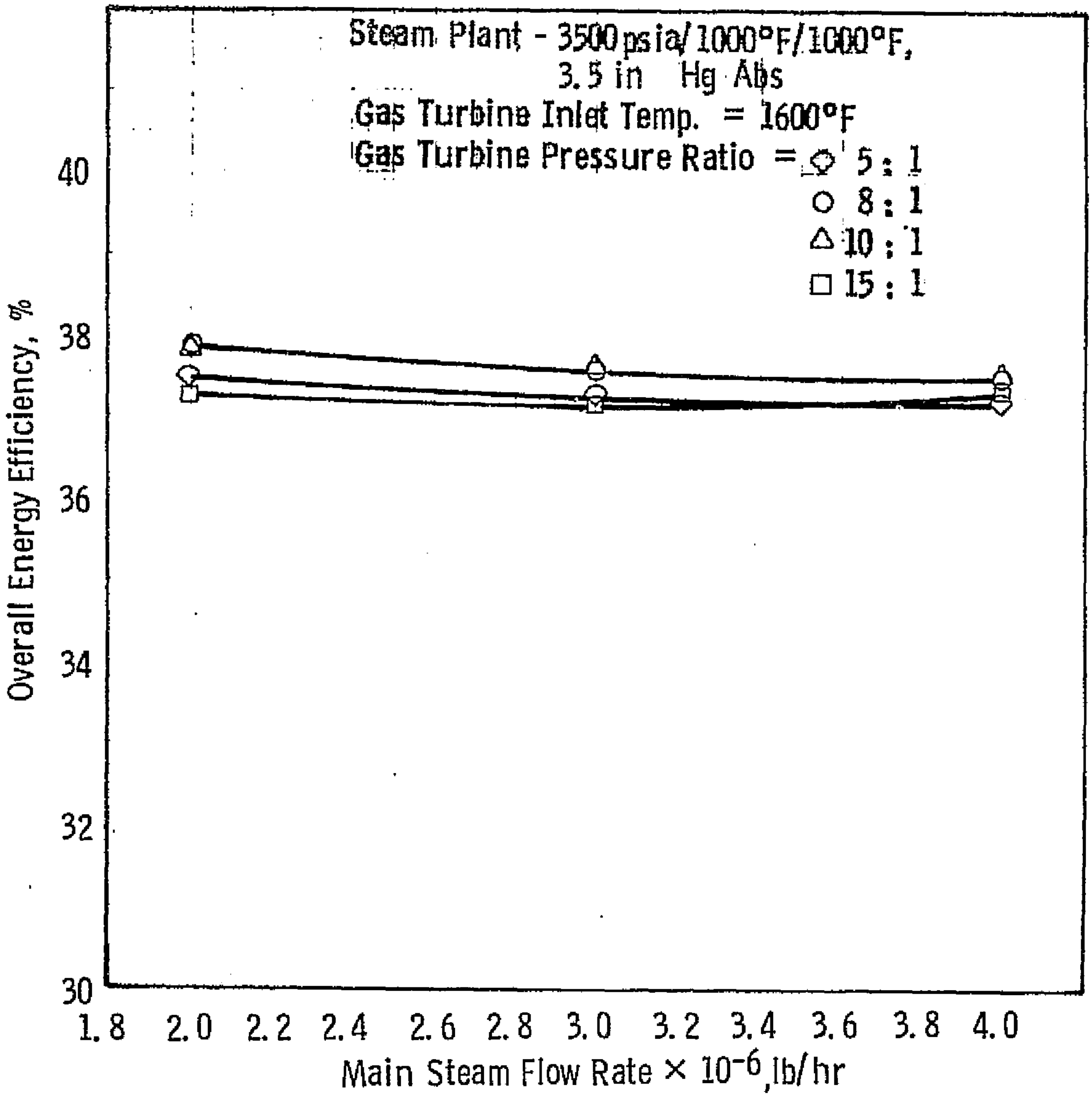

Fig. 12.23—Effect of steam flow rate and pressurizing gas turbine pressure ratio on overall efficiency for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

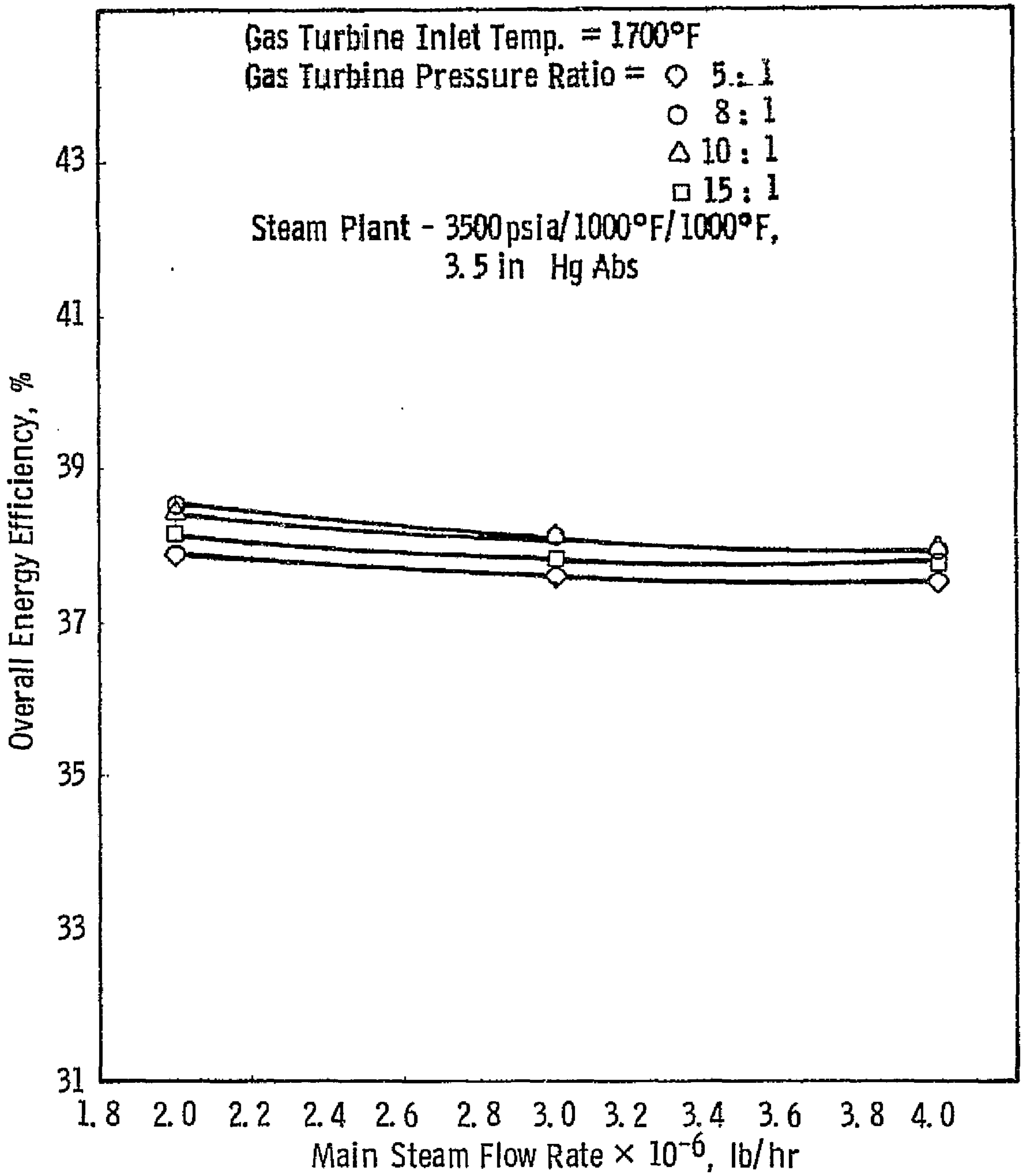

Fig. 12.24—Effect of steam flow rate and pressurizing gas turbine pressure ratio on overall efficiency for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682195-A

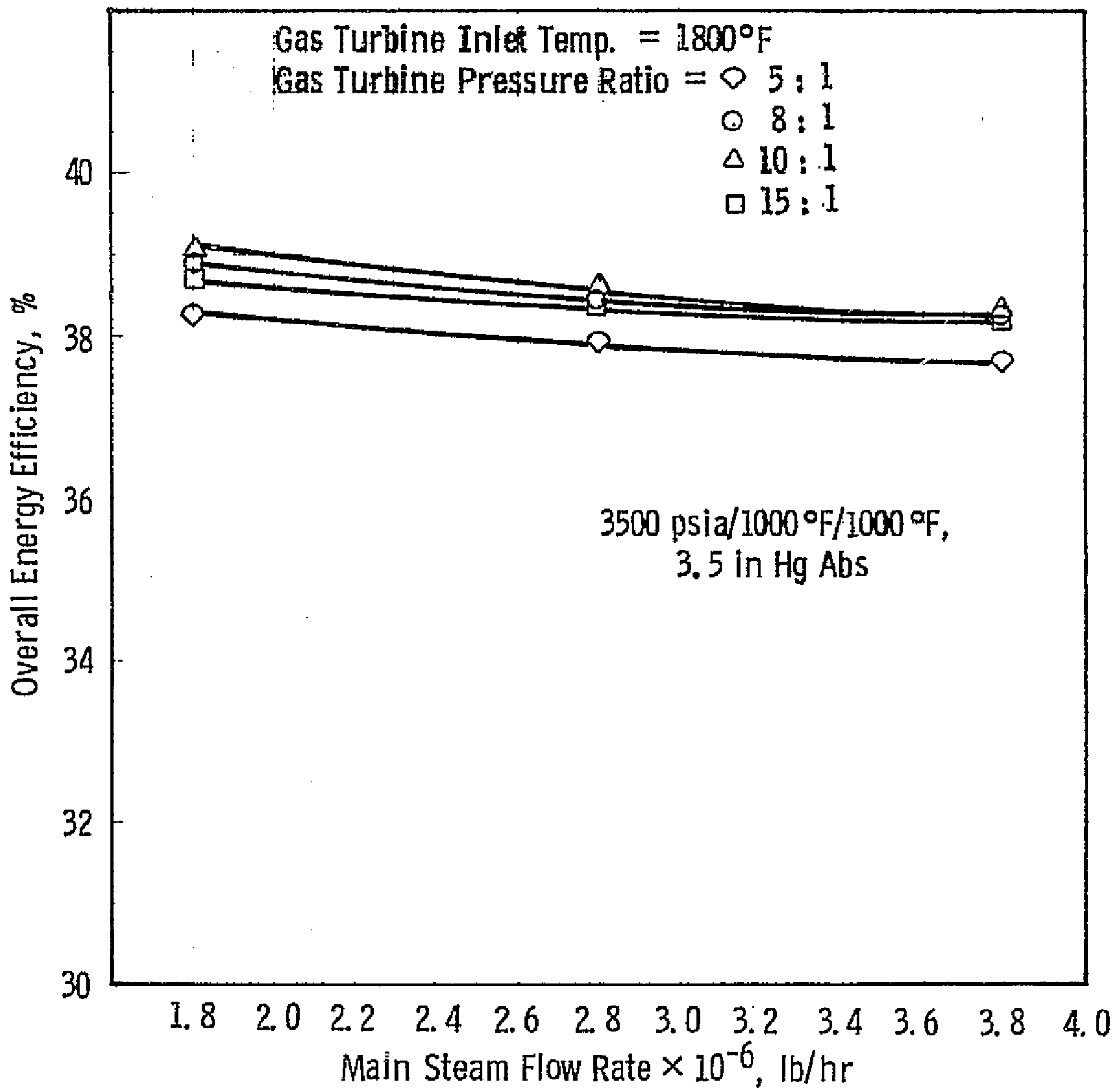

Fig. 12 25—Effect of steam flow rate and pressurizing gas turbine pressure ratio on overall efficiency for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682199-A

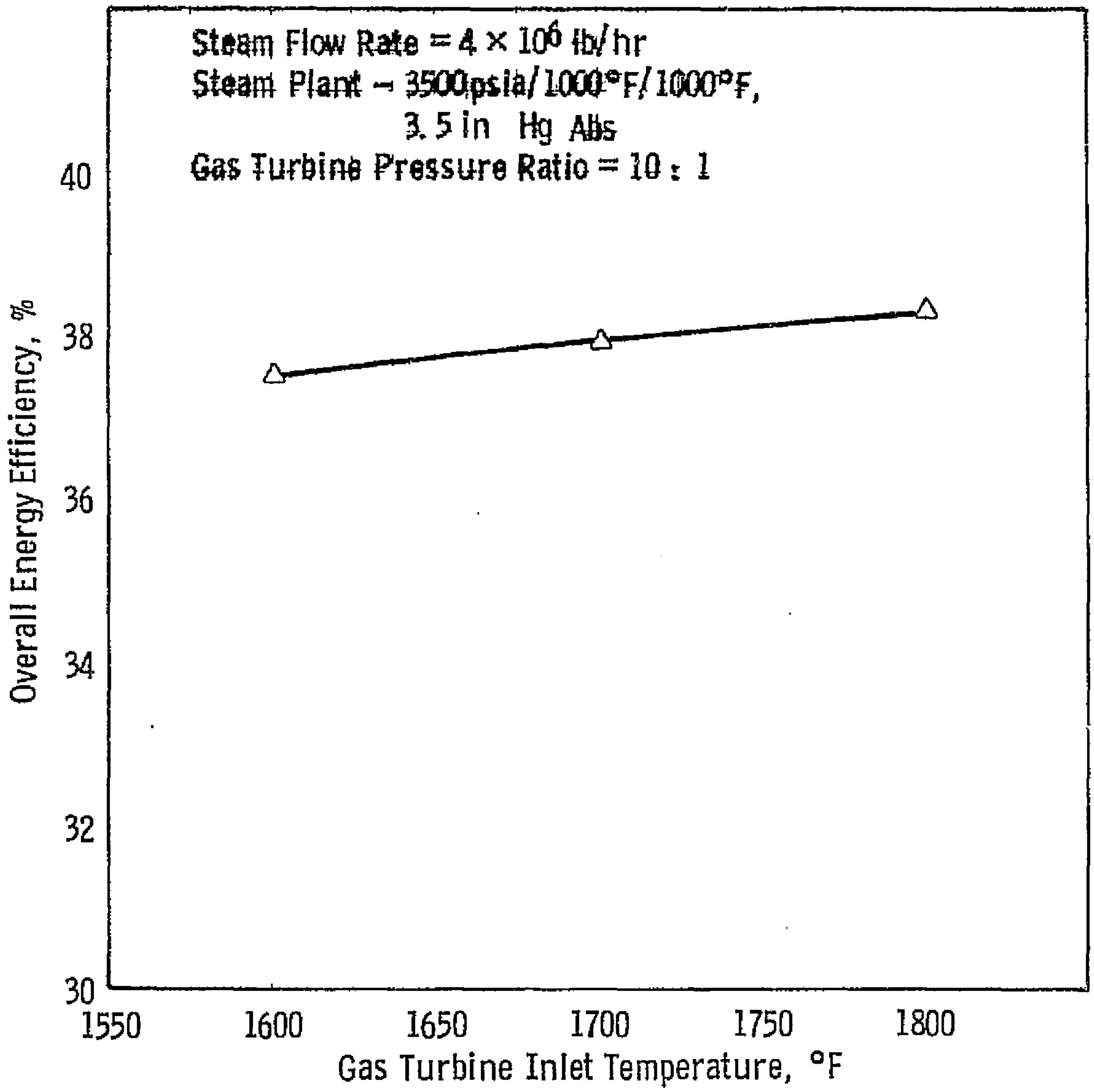

Fig. 12.26—Effect of pressurizing gas turbine inlet temperature on overall efficiency for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682209-A

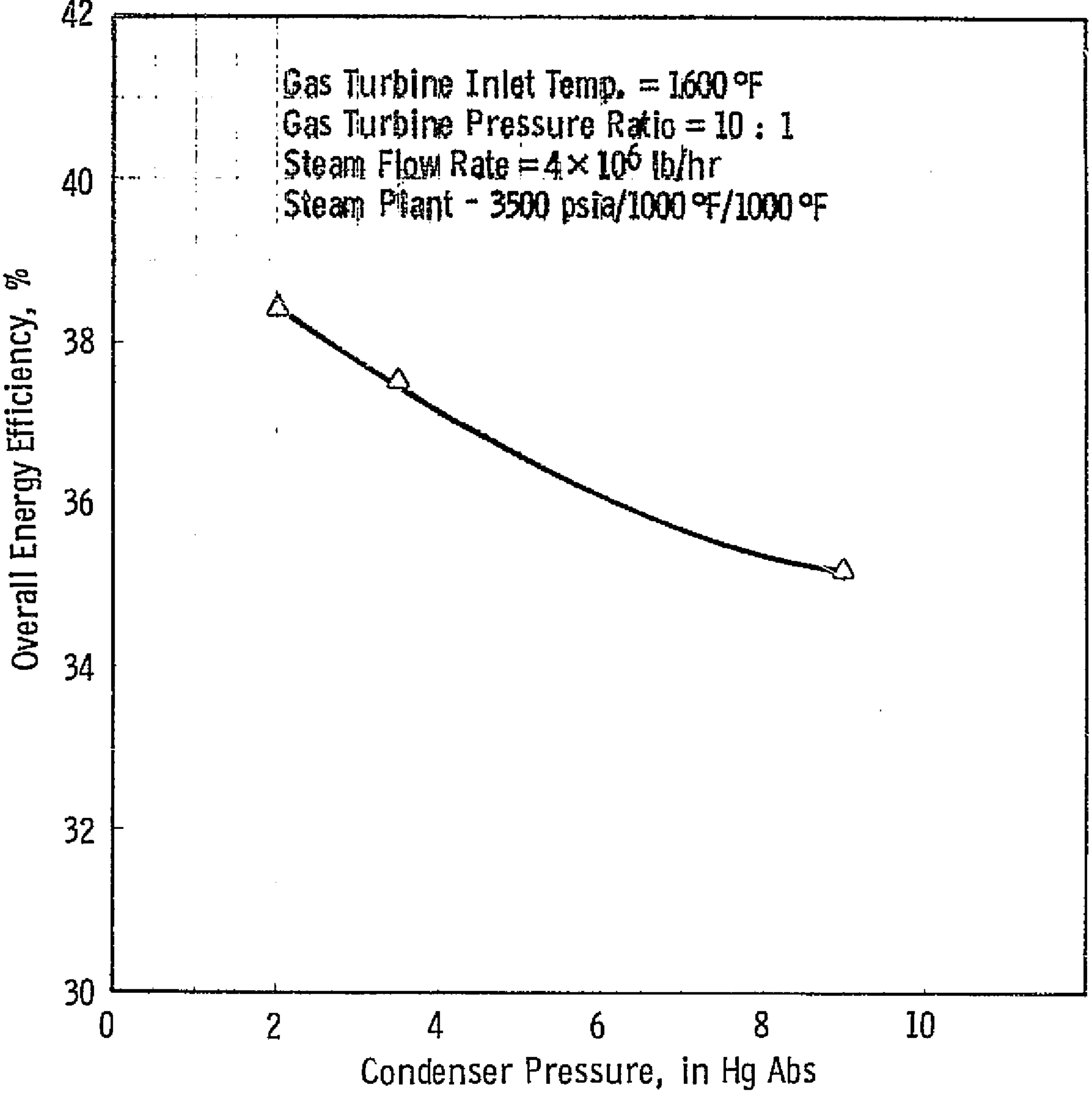

Fig. 12.27—Effect of condenser pressure on overall efficiency for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682208-A

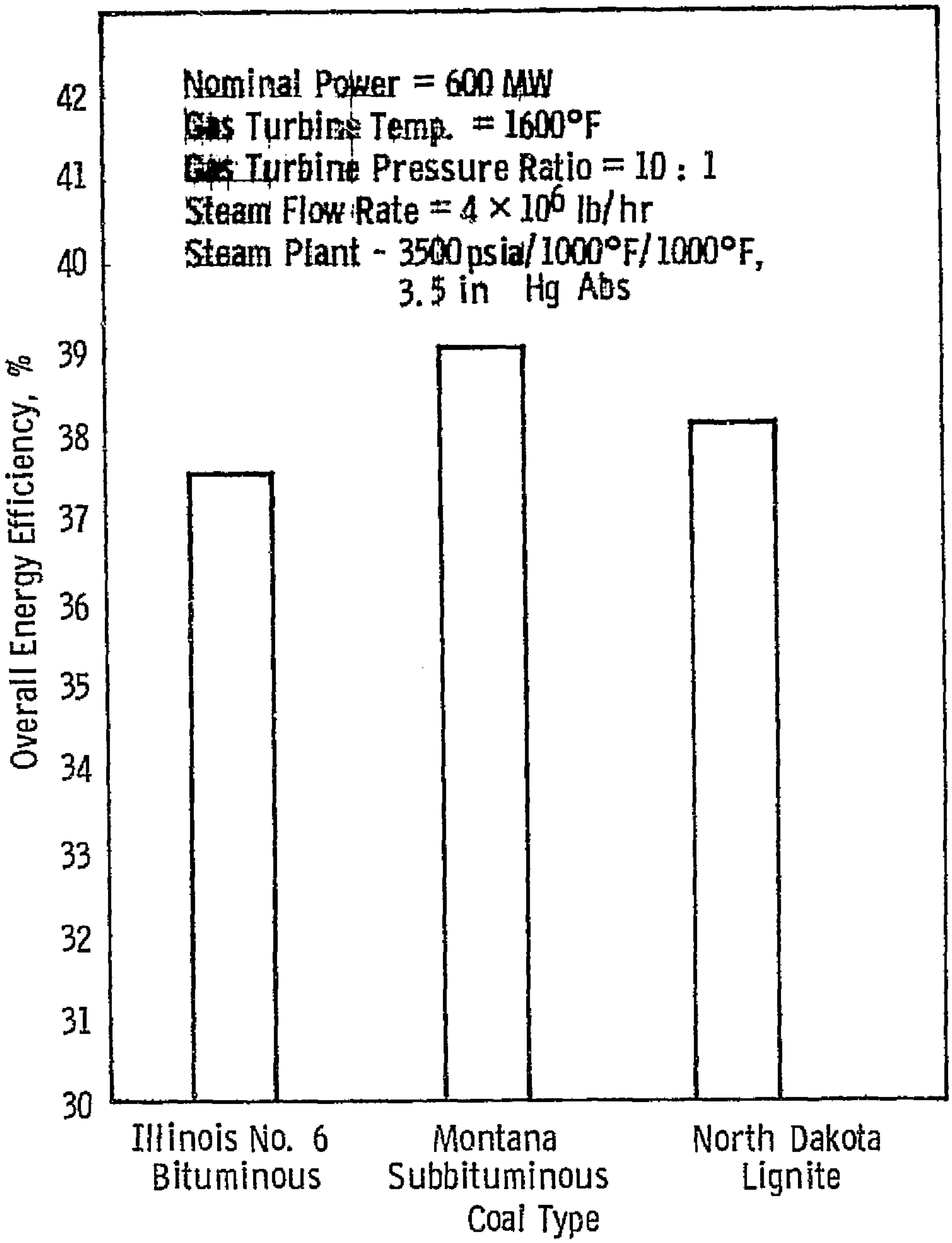

Fig. 12.28—Effect of coal type on overall efficiency for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Finally, Figure 12.29 shows that a substantial increase in efficiency will result from an increase in steam temperature and pressure.

12.5 Capital and Installation Costs of Plant Components

12.5.1 Atmospheric Furnace Systems

12.5.1.1 Boilers

The prices of conventional atmospheric furnace steam boilers at standard and advanced steam conditions were calculated for a range of specified operating conditions by the Foster Wheeler Corporation under subcontract to Westinghouse. The steam conditions supplied to Foster Wheeler are shown in Table 12.11. The prices calculated by Foster Wheeler are shown in Table 12.12.

As can be seen, the price of the boilers increases rapidly with increase in temperature, particularly at the higher pressure of 34.472 MPa (5000 psi). In fact, Foster Wheeler declined to estimate the price of a 34.472 MPa (5000 psi) boiler producing 1033°K (1400°F) steam. For the purposes of the study, therefore, the 34.472 MPa/1033°K/1033°K (5000 psi/1400°F/1400°F) steam boiler price was determined by plotting price versus temperature and extrapolating to the 1033°K (1400°F) level. The reason that Foster Wheeler declined to make the estimate is that they believe the technology required to satisfy these conditions is not sufficiently well defined for price estimation purposes.

Because the relatively large number of parametric steam conditions to be investigated, a representative number was chosen to be priced in detail by Foster Wheeler, and prices for all other conditions were interpolated. Figure 12.30 is a plot of the Foster Wheeler boiler prices versus steam temperature, with the steam conditions for each point noted on the curves. All the price calculations were made for nominal 500 MWe plants. The prices for nominal 900 MWe plants were calculated with the simple scaling formula:

$$(\mathrm{Price}_{900MW}) = (\mathrm{Price}_{500MW}) \left(\frac{900}{500}\right)^{0.89} \qquad (12.1)$$

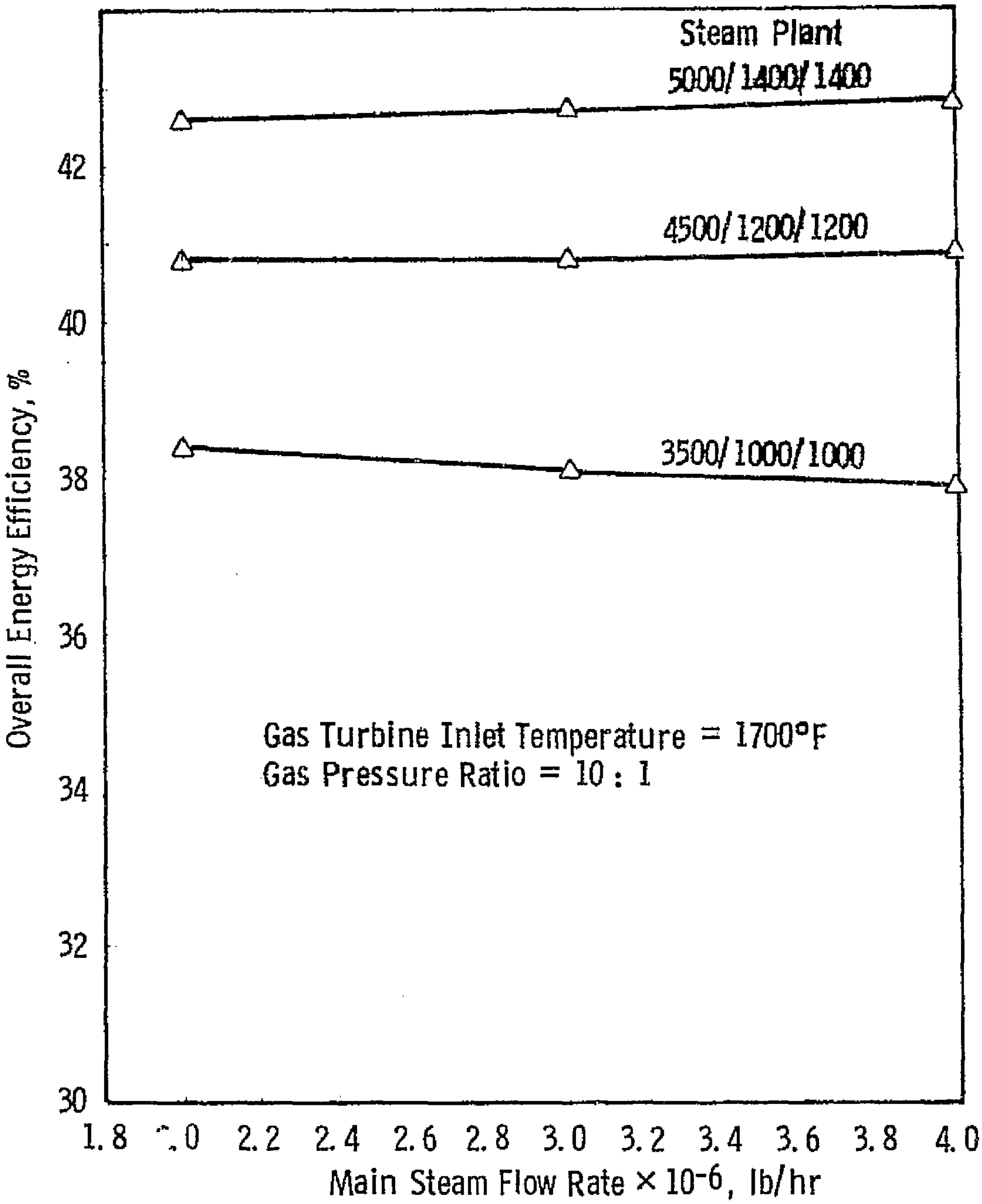

Fig. 12.29—Effect of steam flow rate and steam turbine throttle conditions on overall efficiency for a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Table 12.11 - Atmospheric Pressure Boiler Performance Specification

	Throttle			First Reheat			Second Reheat			F.W.		First Cold	Second Cold
	Press, psia	Temp, °F	Flow, lb/hr	Temp, °F	Press, psia	Flow, lb/hr	Temp, °F	Press, psia	Flow, lb/hr	Temp, °F	Load* MW	Rht.T, °F	Rht.T, °F
1)	5000	1000	3,520,000	1000	1100	2,818,212	1000	350	2,801,924	563	520.6	621	717
2)	5000	1200	3,228,610	1200	1800	2,564,958	1200	600	2,405,788	629	519.8	921	902
3)	5000	1400	2,414,416	1400	1100	2,007,571	1400	350	2,012,940	563	521.2	962	1072
4)	5000	1000	3,236,028	1200	2000	2,286,806	1400	450	2,220,503	643	519.8	769	788
5)	3500	1000	3,515,412	1000	1300	3,096,373	-	-	-	584	521.4	570	-
6)	3500	1200	2,928,516	1200	600	2,603,877	-	-	-	492	521.5	731	-
7)	3500	1400	2,393,811	1400	450	2,213,746	-	-	-	462	521.8	825	-
8)	3500	1200	2,662,053	1400	600	2,352,980	-	-	-	492	521.5	731	-
9)	3500	1400	3,057,206	-	-	-	-	-	-	480	522.5	-	-
10)	2400	1000	3,620,509	1000	600	3,228,487	-	-	-	492	520.5	644	-
11)	2400	1200	3,056,834	1200	600	2,749,[illegible]9	-	-	-	492	520.9	837	-
12)	2400	1400	3,157,693	-	-	-	-	-	-	480	522.4	-	-

* Corresponds to a back pressure of 3.5 in Hg abs.

Table 12.12 - Prices Calculated for Boilers

	Budget Price,$	Estimated Wt. (tons)	Furnace Dimensions,ft W	D	H	Add to Ill.No. 6 coal, cost & weight for alt. fuel units Mont. (Rosebud)	N. Dak. Lignite	
1)	34,606,000	17,341	53.4	45.0	143.0			For all units firing Montana (Rosebud) coal add 6% to furnace width. For all units firing North Dakota Lignite add 18% to furnace width.
2)	57,147,000	17,556	49.4	45.0	132.0	+5.8%	+15.7%	
See note 2 for Case 3								
4)	58,659,000	17,874	49.7	45.0	133.0			
5)	29,375,000 ⟷	14.627 ⟵⟶	49.6	45.0	133.0			
6)	34,026,000	11,841	52.1	45.0	139.0			This budget price is for materials erection supervision, field erection costs (total installation price) on a today's price basis. Avg. U.S. field erection is estimated at 50% of the materials cost.
7)	38,882,000	9,827	49.4	45.0	132.0	+6.5%	+20.9%	
8)	39,908,000	11,044	50.7	45.0	135.0			
9)	37,018,000	12,117	50.4	45.0	135.0			
10)	25,110,000	12,668	56.8	45.0	152.0			
11)	30,707,000	11,035	53.2	45.0	142.0	+6.2%	+22.6%	
12)	34,863,000	10,655	52.8	45.0	141.0			

NOTE 1: The budget pricing above makes no allowance for the developmental engineering which would be necessary for the advanced steam applications.

NOTE 2: Case No. 3 - As we determine that this case would require the use of cast superalloys at the high-temperature locations, this is not considered feasible with present materials.

NOTE 3: Case No. 5 - RH inlet conditions 580°F, 650 psig assumed. Furnace size, heat input, and cost will have to be scaled up to meet 520 MWe output.

Curve 682234-A

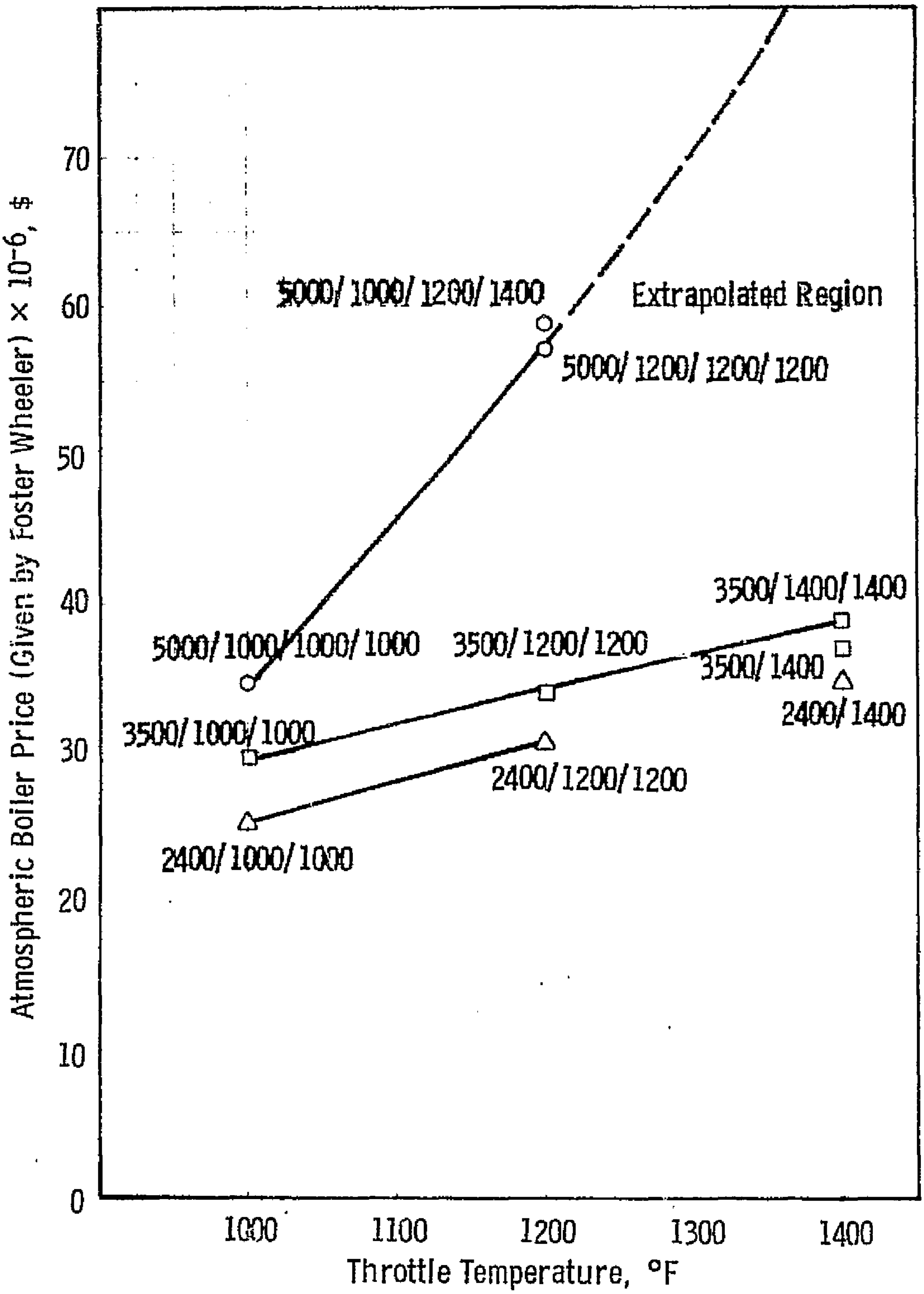

Fig. 12.30—Effect of steam turbine throttle conditions on the price of a 500 MWe steam plant with atmospheric furnace

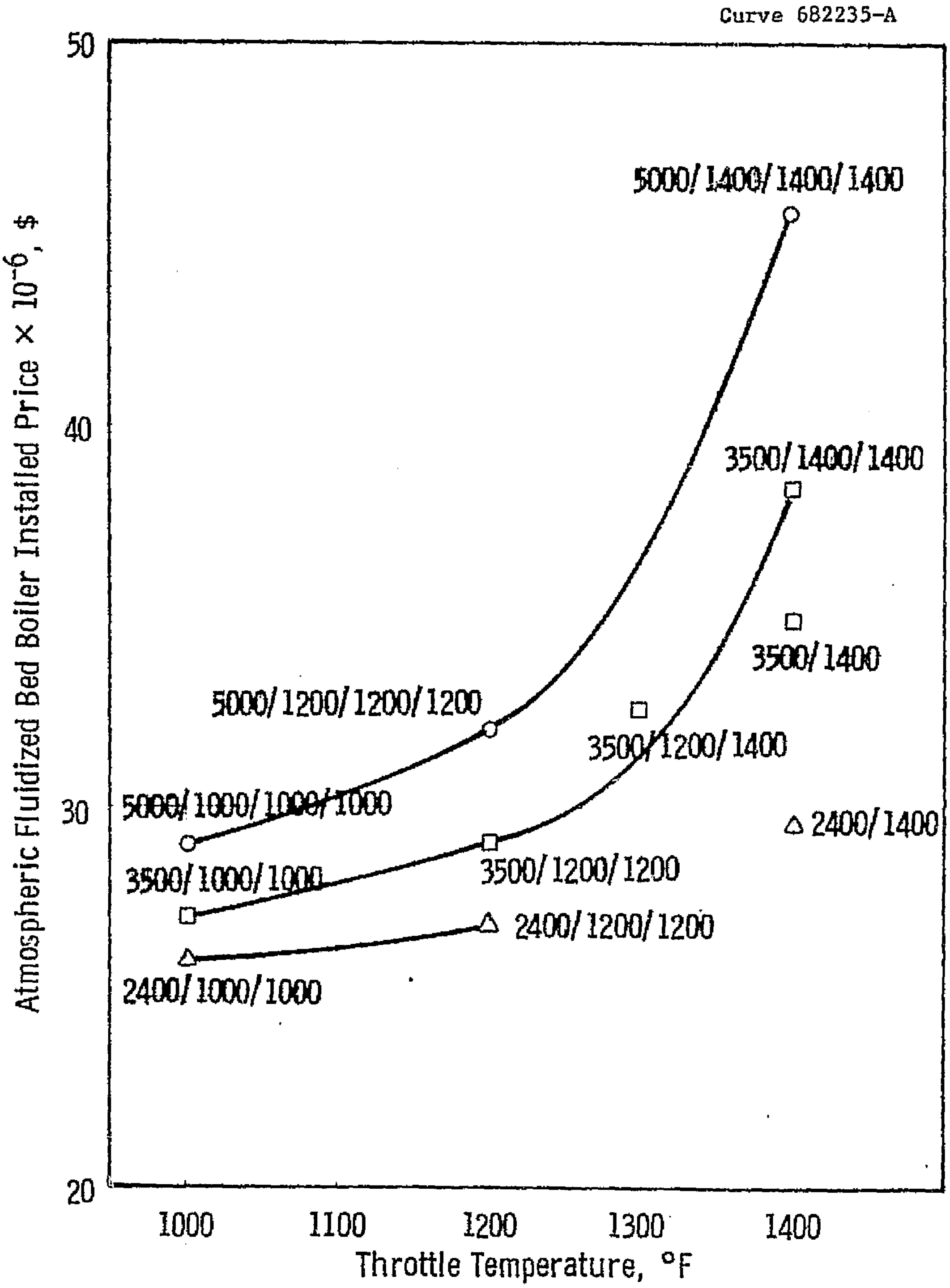

Fig. 12.31—Effect of steam turbine throttle conditions on the installed price of a nominal 500 MWe steam plant atmospheric fluidized bed boiler

The prices shown are installed prices. Foster Wheeler stated that the price of installation is 50% of the delivered material price. Thus installation price is one-third of the total price shown.

The prices of the atmospheric fluidized bed boiler were calculated in-house, and the methods used to calculate these prices are described in detail in Section 4 of this report. Figure 12.31 is a plot of the calculated prices as a function of steam temperature. It is interesting to note the comparison between the shape of the curves for the Foster Wheeler and Westinghouse boilers. The Foster Wheeler boiler prices increase substantially linearly with steam temperature, whereas the Westinghouse prices increase at a greater rate between 922 and 1033°K (1200 and 1400°F) than between 811 and 922°K (1000 and 1200°F). This resulted from the need to use tube materials at the hot end of the 1033°K (1400°F) boilers, which were markedly higher in price.

12.5.1.2 Steam Turbine-Generator

The prices of steam turbine-generator units were calculated by the Westinghouse Steam Turbine Division Marketing Department for a range of specified steam operating conditions.

Details of the methods used to calculate the turbine-generator prices are presented in Appendix A 12.1. A summary of prices for 500 MWe and 900 MWe units is given in Tables 12.13 and 12.14. In order to facilitate the interpolation of prices for units corresponding to the balance of the parametric points, the calculated prices were plotted versus steam temperature in Figures 12.32 to 12.37. Turbine prices increase substantially with increasing steam temperature (similar to the price increase with temperature seen in boiler prices).

Due to a communication error, prices shown in both the figures and tables are for units delivered in mid-1974. The tabulated prices were multiplied by a factor of 1.2456 to obtain the price for units ordered in mid-1974 as required in this study.

Table 12.13 - 500 MWe Steam Turbine-Generator Pricing Summary

Item	Initial Press, psig	Initial T, °F	1st Rht, °F	2nd Rht, °F	3rd Rht, °F	1974 Net Selling Price x 10^{-3}, $* 2.0 in Hg abs	3.5 in Hg abs	9.0 in Hg abs	Remarks
1	10000	1000	1000	1000	1000				
2	5000	1000	1000	1000		15,635			
3	5000	1200	1200	1200		53,168			Cross-compound
4	5000	1400	1400	1400		98,768			Cross-compound
5	5000	1000	1200	1200		44,618			Cross-compound
5I	5000	1000	1200	1400		64,568			Cross-compound
6	5000	1000	1000	1400		56,018			Cross-compound
7	3500	1000	1000	1000		13,811			
7I	3500	1000	1000	1000		-			
8	3500	1000	1200	1200		42,774			Cross-compound
9	3500	1000	1000			12,849	11,545	14,385	
10	3500	1200	1200			29,949			
11	3500	1400	1400			55,599			
12	3500	1000	1200			21,399			
13	3500	1000	1400			29,949			
14	3500	1200	1400			38,499			
15	3500	1400				41,349			
16	2400	1000	1000			12,901	11,608	14,453	
17	2400	1200	1200			30,001	28,708	31,553	
18	2400	1400				41,401			
19	2400	1000	1200			21,451			
20	2400	1200	1400			38,551	37,258	40,103	

* For units shipped in 1974, multiply by 1.246 for pricing of turbines ordered in mid-1974.

Table 12.14 - 900 MWe Steam Turbine-Generator Pricing Summary

Item	Initial Press, Psig	Initial T, °F	1st Rht, °F	2nd Rht, °F	1974 Net Selling Price x 10^{-3}, $* 2.0 in Hg abs	3.5 in Hg abs	Remarks
2	5000	1000	1000	1000	24,593	23,247	
3	5000	1200	1200	1200	64,562	63,152	Cross-compound
4	5000	1400	1400	1400	113,012	111,602	Cross-compound
7	3500	1000	1000	1000	22,313	20,967	
8	3500	1000	1200	1200	53,732	52,322	Cross-compound
9	3500	1000	1000		21,128	19,775	
10	3500	1200	1200		41,078	39,725	
11	3500	1400	1400		69,578	68,225	
16	2400	1000	1000		21,767	20,442	
17	2400	1200	1200		41,717	40,392	

* For units shipped in 1974, multiply by 1.246 for pricing of turbines ordered in mid-1974.

Curve 682236-A

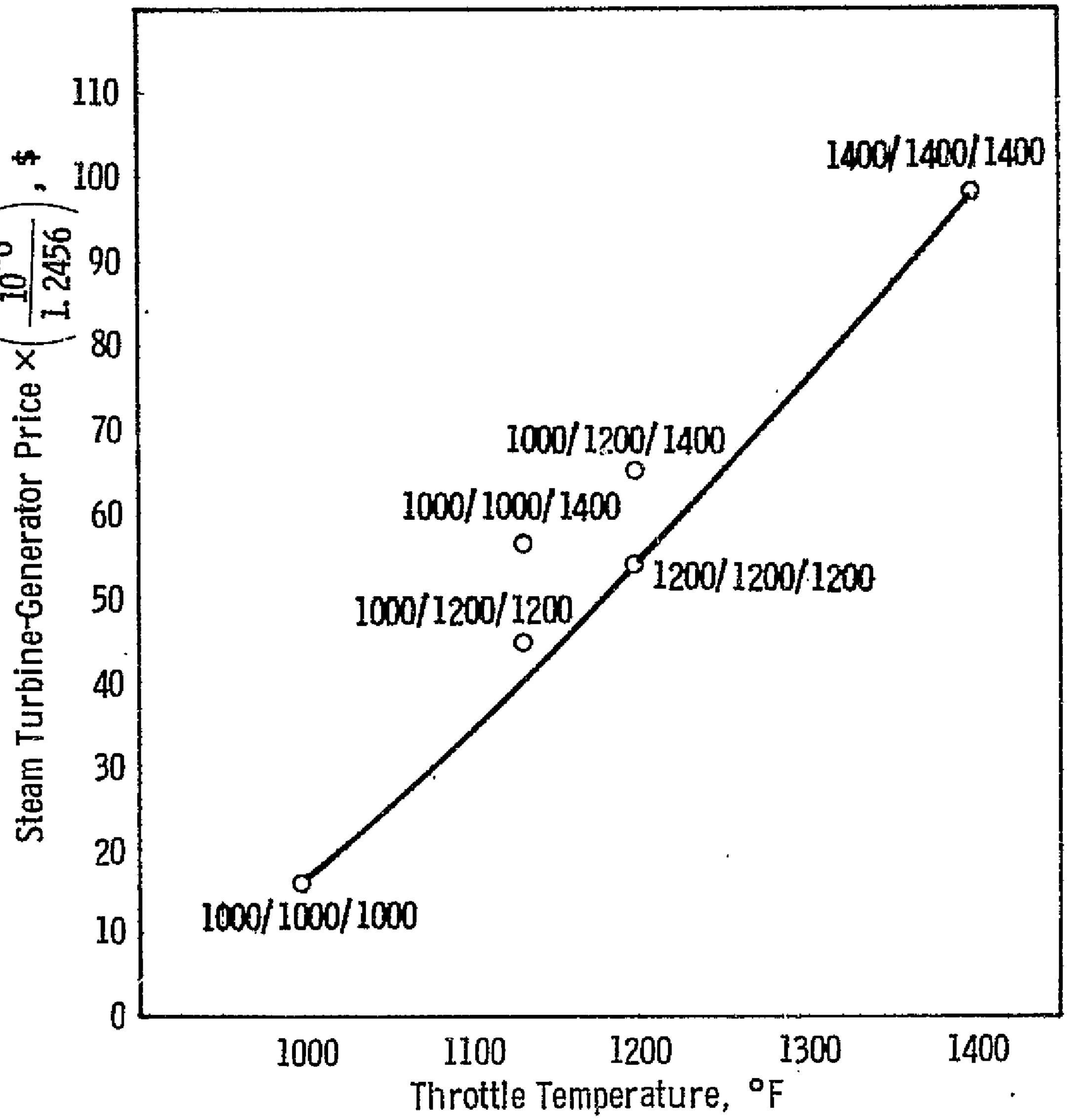

Fig. 12.32—Effect of steam turbine throttle conditions on 500 MWe steam turbine generator pricing

Curve 682232-A

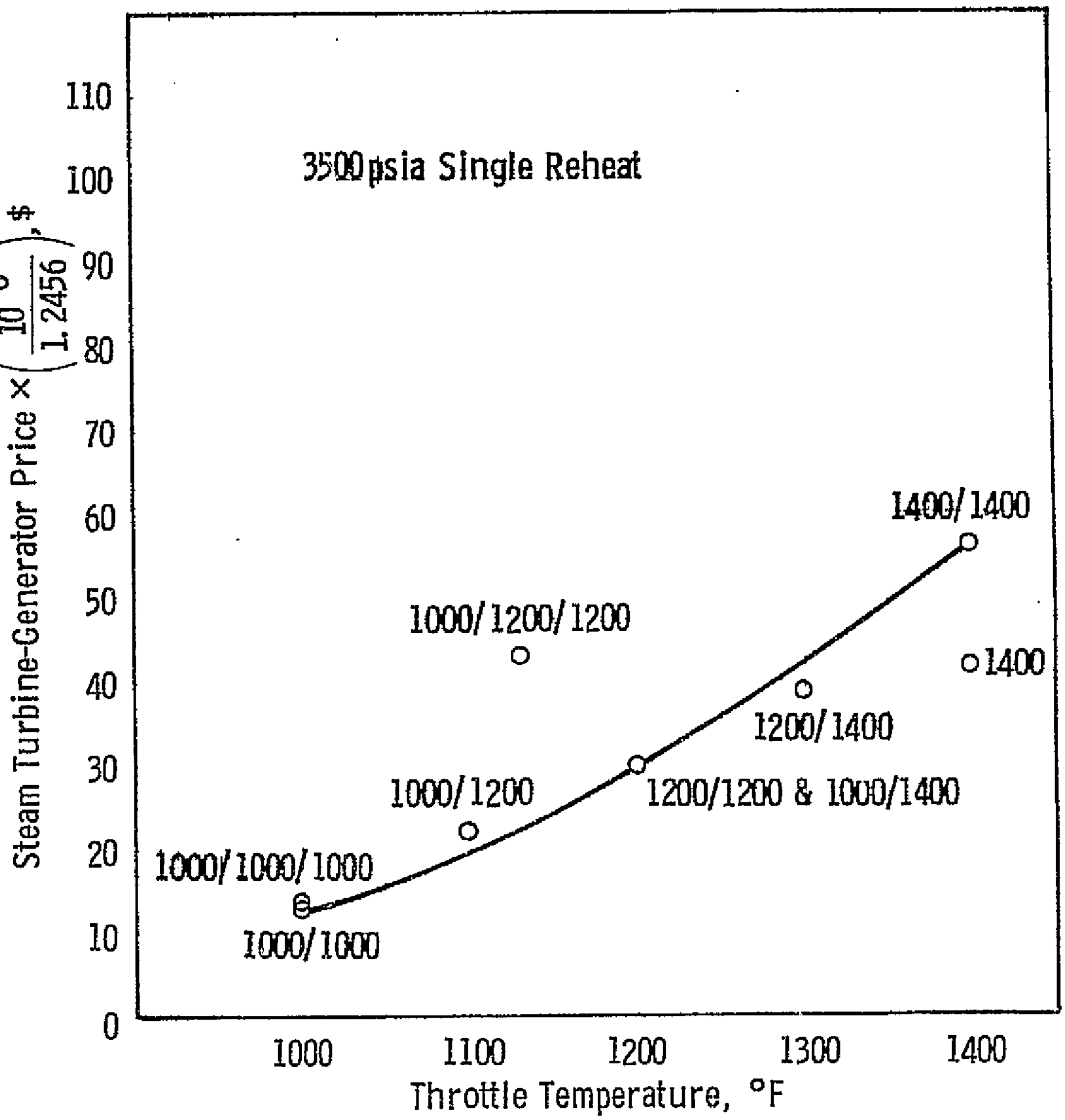

Fig. 12.33—Effect of steam turbine throttle conditions on 500 MWe steam turbine generator price

Curve 682239-A

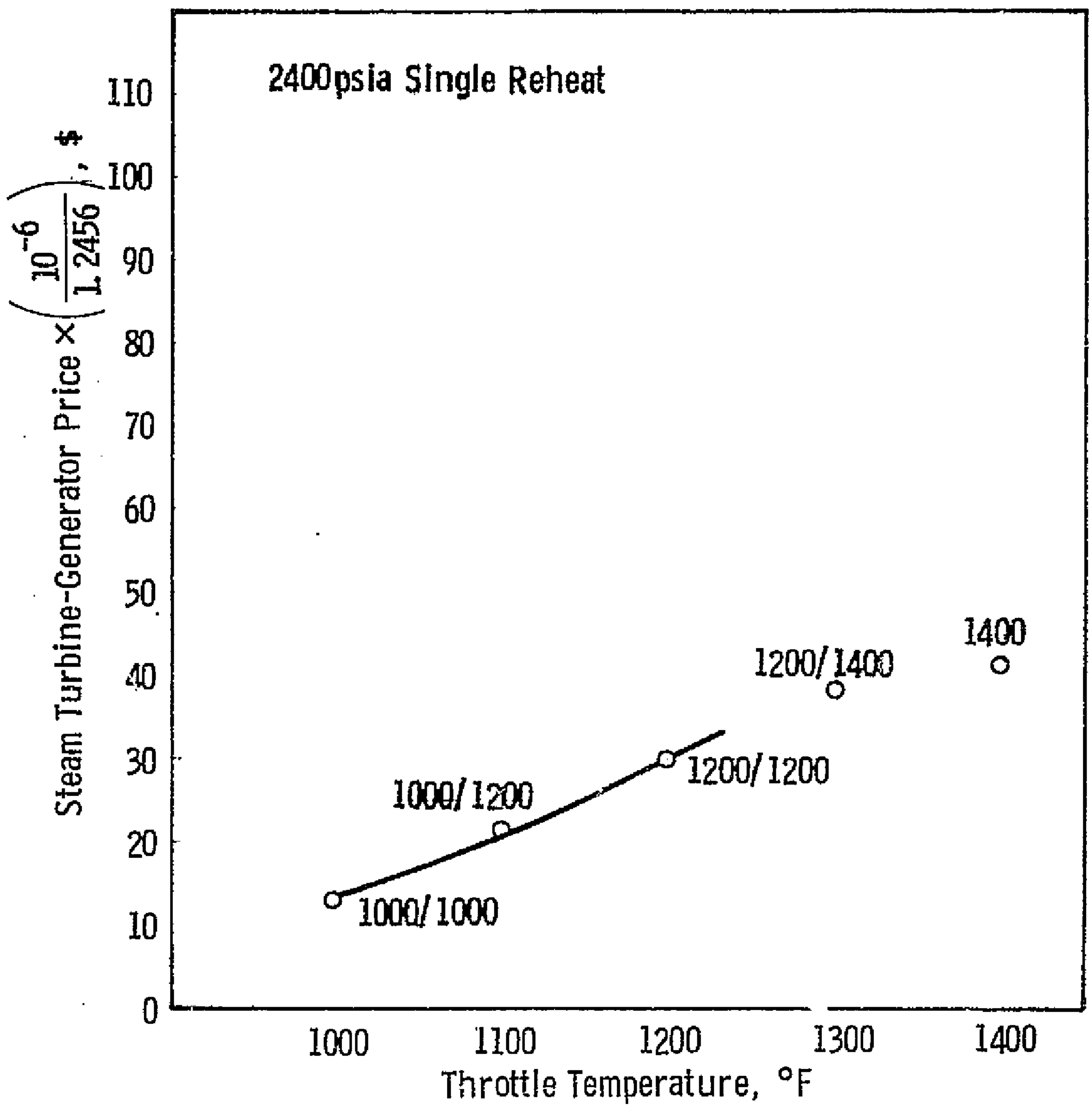

Fig. 12.34—Effect of steam turbine throttle conditions on 500 MWe steam turbine-generator price

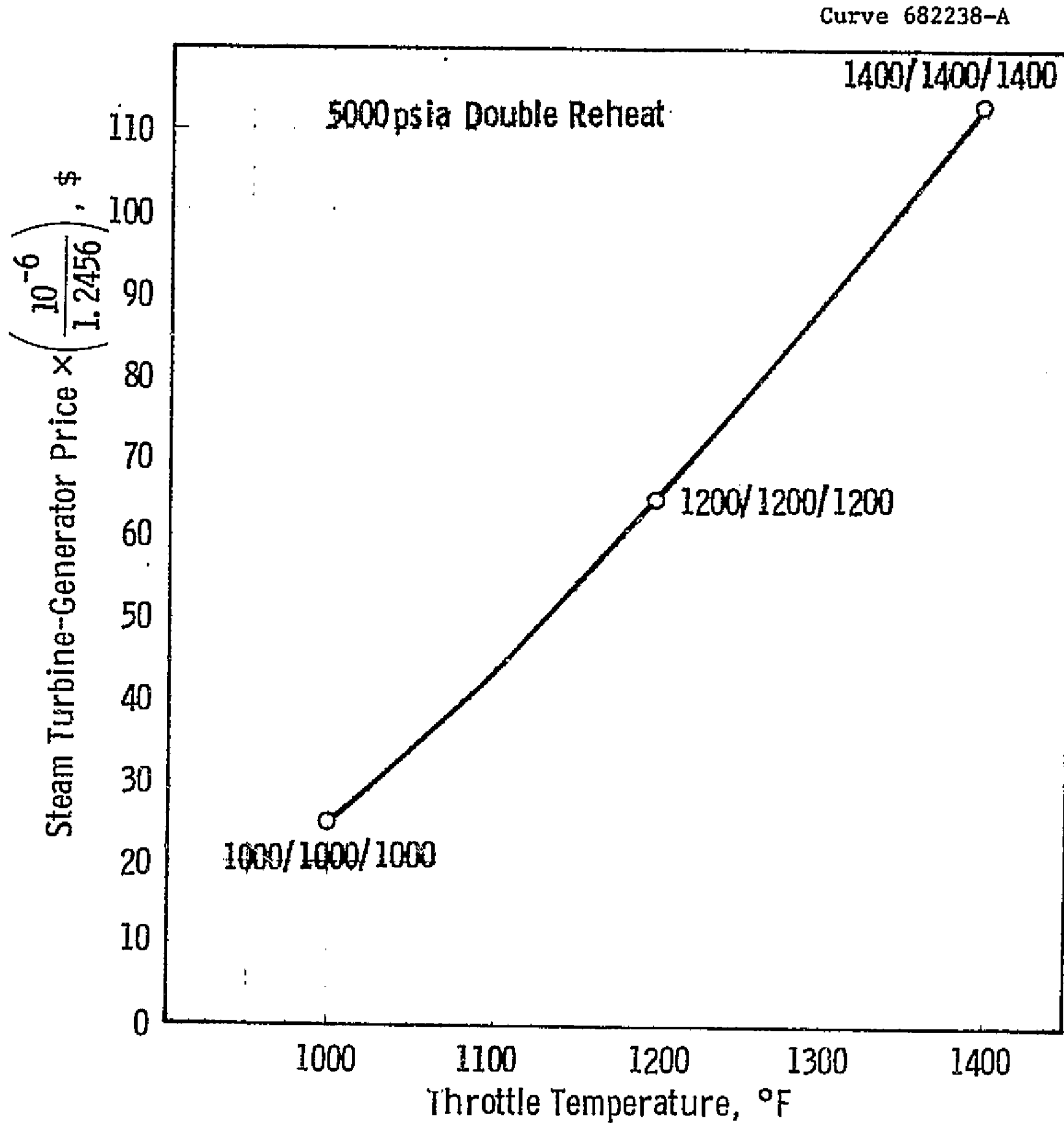

Fig. 12.35—Effect of steam turbine throttle conditions on 900 MWe steam turbine-generator price

Curve 682233-A

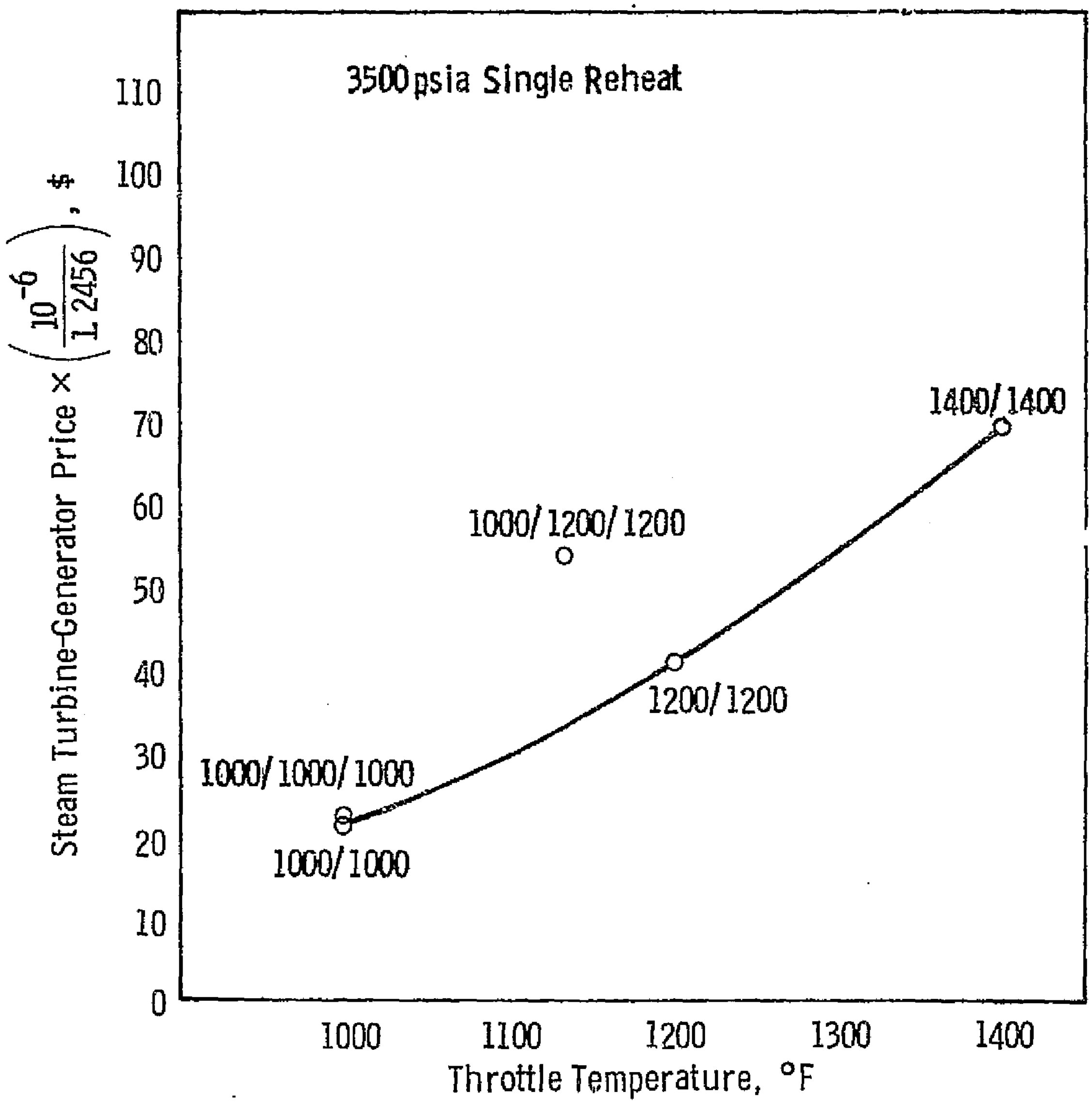

Fig. 12.36—Effect of steam turbine throttle conditions on 900 MWe steam turbine generator price

Curve 682237-A

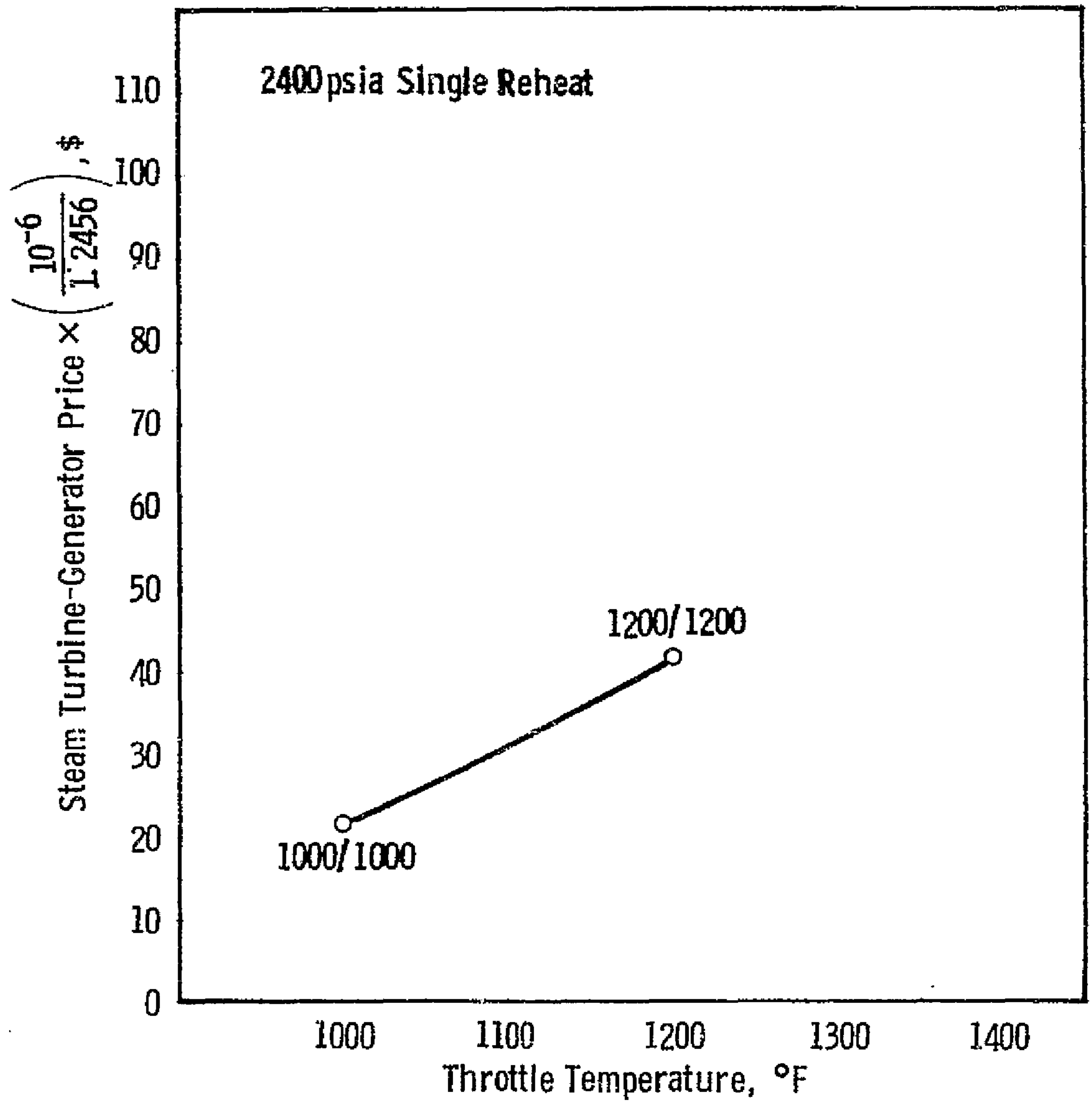

Fig. 12.37—Effect of steam turbine throttle conditions on 900 MWe steam turbine-generator price

12.5.1.3 Steam Piping

Included under the category of steam piping is the piping for the main steam, the hot reheat steam, and the cold reheat steam. All other piping is included in the general category of piping in the balance of plant costs calculated by the A/E.

The price of the steam piping is based on the known price for a given 16.547 MPa/811°K/811°K (2400 psi/1000°F/1000°F) 750 MWe plant. This price is $2,100,000 for material and $840,000 for installation. To arrive at prices at other conditions for each of the parametric points investigated, the following equation is used:

Material price = (base price material)(flow factor) (pressure factor) (temperature factor) (reheat factor) (12.2)

where the flow factor is (steam flow rate, in lb/hr) 4,811,700

pressure factor	=	1.15 for 3500 psi
		1.3 for 5000 psi
temperature factor*	=	6.7 for 1200°F
		21.3 for 1400°F
and the reheat factor	=	0.75 for no reheat
		1 for one reheat
		1.2 for two reheats

Erection price = (base price installation)(flow factor) (pressure factor)(temperature factor) (reheat factor) (12.3)

* Combination of increased material cost and increase in required material due to lower allowable stress

where the flow factor is the same as in Equation 12.2

pressure factor = the same as in Equation 12.2

temperature factor* = 1.3 for 1200°F

3.2 for 1400°F

reheat factor = the same as in Equation 12.2

12.5.1.4 Feedwater Heaters

The primary variables affecting the cost of feedwater heaters are the pressure level of the throttle steam and their capacity (i.e., the heat transferred in them). Their capacity, in turn, is approximately proportional to the throttle steam flow rate. Thus for a known price of \$1,150,000 for a 500 MWe, 24.132 MPa/811°K/811°K (3500 psi/1000°F/1000°F) steam plant with a throttle steam flow rate of 443 kg/s (3,515,000 lb/hr), the price is given by:

$$\text{Feedwater heater price, \$} = (1.15 \times 10^6)\left(\frac{\dot{M}}{3.515 \times 10^6}\right)(\text{pressure factor}) \qquad (12.4)$$

where $\dot{M}$ = the throttle steam flow rate (lb/hr),

pressure factor = 1.15 for 5000 psi and

0.85 for 2400 psi.

12.5.2 Pressurized Boiler-Gasifier Systems

12.5.2.1 Boiler

The basic cost advantage of the pressurized boiler is the reduction in heat transfer surface due to the higher convection and radiation heat transfer coefficients on the hot gas side resulting from the elevated gas pressure. In addition, the use of a clean low-Btu fuel gas permits the use of a water-walled multicell combustor configuration which improves the ratio of heat transfer area to combustor volume. These two factors, in conjunction with the use of two boiler units for each gas turbine, results in a relatively simple and compact unit.

* Due to an increase in required material resulting from lower allowable stress; increase in raw material cost has no effect.

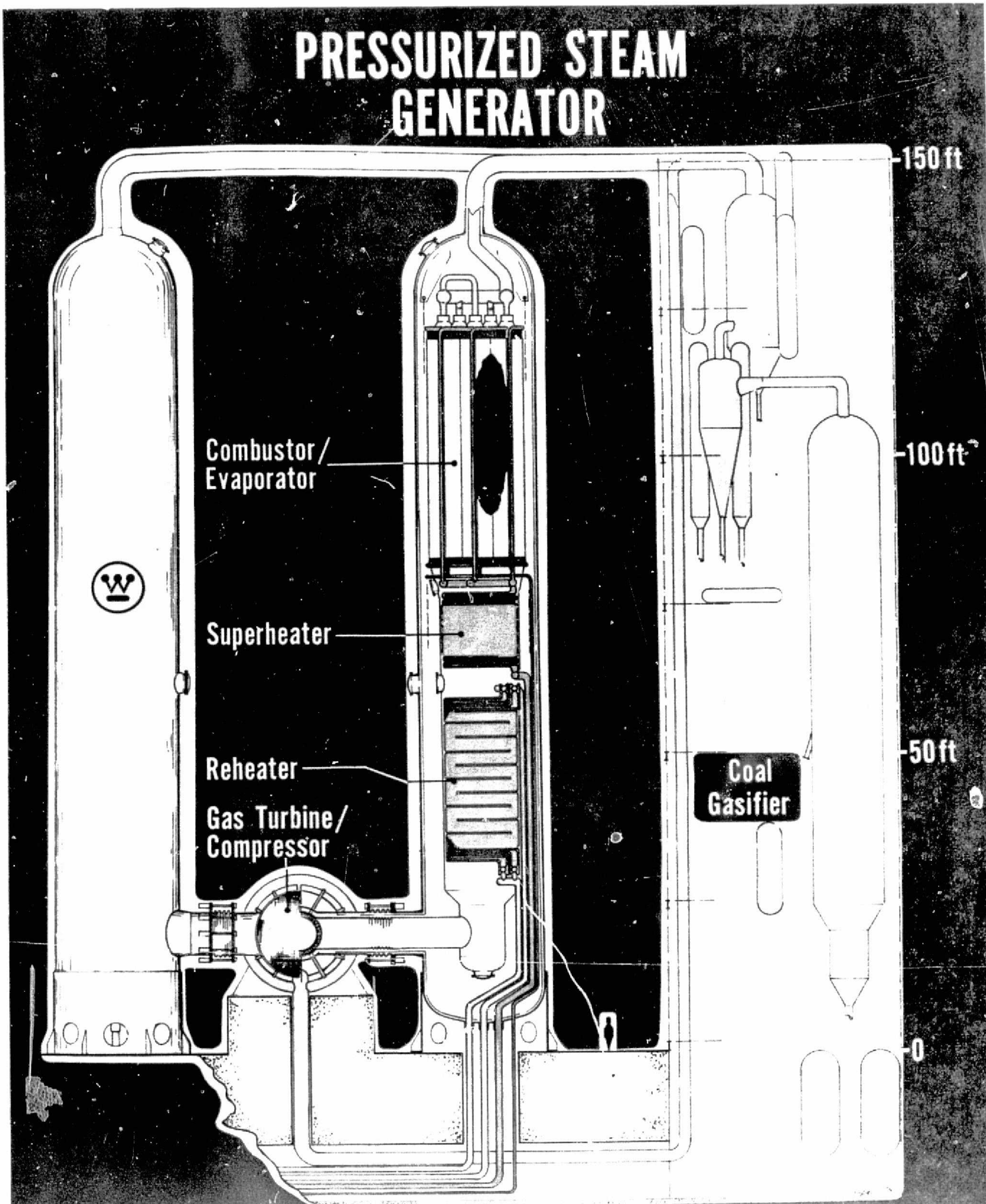

Fig. 12.38—Pressurized steam generator (One Unit (sectioned) produces 260 MWt, two units are close coupled to one coal gasifier and one turbine generator/air compressor)

Figure 12.38 shows the design configuration upon which the cost evaluation has been made.

Appendix A 12.2 describes the heat transfer analysis tha was made to calculate the required area and size needed for the base case to deliver the steam determined from the cycle performance calculations. The cost was then developed from tubing price quotations with appropriate adders for fabrication and auxiliary hardware required for a complete functional unit.

The pressure vessel was designed in conformance with the ASME boiler code for fired vessels. Because of its size [nominally 6.1 m (20 ft) in diameter by 30.5 m (100 ft) long] it had to be field fabricated. The assumption, therefore, was that the heat treatment and x-ray inspection of the welds would also be performed in the field.

The assumed boiler construction was such that the relatively cool compressor discharge air flowed in an annular space between the pressure wall and an inner wall which supports the steam generator tubing. For most of the pressure levels of interest, however, the air temperature was high enough to require insulation on the inside of the pressure vessel wall to maintain a low metal-working temperature and to minimize heat losses.

Table 12.15 gives the weights and costs of a boiler unit for the base case. Appendix A 12.3 is a description of the method used to calculate the costs for the different operating conditions corresponding to the various parametric points investigated. Basically the method was to ratio the costs of appropriate components as a function of pressure level and gas flow rate, which in turn affects the gas-side heat transfer coefficient. Also, the cost is ratioed by the flow rate of the steam generated, since this determines the amount of heat which must be transferred. Finally, a factor of 1.88 and 3.84 for 922 and 1033°K (1200 and 1400°F) steam, respectively, was applied to the superheater and reheater elements to account for the increased material cost corresponding to the higher required operating temperature. These factors were derived from

Table 12.15 - Pressurized Boiler Price Analysis
3500 psi/1000°F/1000°F)

	Component weight, lb	Material unit cost, \$/lb	Installation unit cost, \$/lb	Total Cost x 10^{-3}, \$ Total \$/lb	Material	Instal-lation	Total
1. Burner Section (Evaporator)							
1.1 Tubing (1-1/4 Cr, SA 213, 2 in od x 0.375 in wall)	98,000	0.57	1.00	1.57	56	98	154
1.2 Structural plate	60,000	0.50	0.16	0.66	30	10	40
1.3 Refractory	-						
1.4 Tube anchors (@ 5 lbs/tube)	2,500	0.80	2.00	2.80	2	5	7
1.5 Tube headers (6 in id)	32,000	0.63	0.63	1.26	20	20	40
1.6 Steam risers (6 in id)	57,000	0.35	0.35	0.70	20	20	40
1.7 Fittings	-				10		
2. Superheater							
2.1 Tubing (2-1/4 Croloy, 2 in od x 0.375 in wall)	103,000	1.16	0.24	1.40	120	25	145
2.2 Header piping & fittings (8 in id)	11,000	0.64	0.91	1.55	7	10	17
2.3 Turbine piping & fittings (8 in id)	11,000	0.64	0.91	1.55	7	10	17
2.4 Structural steel	30,000	0.40	0.26	0.66	12	8	20
3. Reheater							
3.1 Tubing (2-1/4 Croloy, 2 in od x 0.375 in wall)	206,000	1.16	0.20	1.00	240	42	282
3.2 Structural steel	50,000	0.40	0.26	0.66	12	8	20
3.3 Header piping (8 in id)	11,000	0.64	0.91	1.55	7	10	17
4. Pressure Vessel (SA 515, Grade 55, σ = 13,700 psi t = 1.5 in, D = 20 ft)							
4.1 Vessel fabricated	434,000	0.80	1.40	2.20	350	310	660
4.2 Refractory	176,000	0.39	0.37	0.76	69	65	134
4.3 Anchors	38,000	0.29	0.29	0.58	11	11	22
5. Burner Apparatus							
5.1 Burners and header pipe	--				25	-	25
5.2 Vessel, burner instruments	--				25	-	25
	1,250,000				1023	652	1,675
6. Contingency @ 15%							251
							1,936 per unit
							4 units reqd.

detailed analysis done for these various temperature levels in the pressurized fluidized bed steam boilers (see Section 4).

12.5.2.2 Steam Turbine-Generator

The prices of the steam turbine-generator units for the pressurized boiler-gasifier system are based on the prices determined for the atmospheric boiler systems. The following equation was derived from the prices established at the 500 and 900 MWe level:

$$\text{Price} = (\text{Price}_{500})\ (\text{MW}/500)^{0.92} \tag{12.5}$$

The value of MW used in the formula, of course, is the power generated by the steam portion of the power plant. The price depends upon steam temperature and pressure, and the reference value at 500 MWe was taken at steam conditions similar to the parametric point being calculated.

12.5.2.3 Steam Piping

The steam piping was priced on the same basis as for the atmospheric boiler case except that it was estimated that the multiple boiler arrangement for the pressurized boiler case would increase the price by a factor of 1.5.

12.5.2.4 Feedwater Heaters

For given steam conditions, the price of feedwater heaters is proportional to the quantity of the heat transferred in them. In the case of this pressurized cycle the heat transferred in the feedwater heaters is not directly proportional to the main throttle steam flow rate because a portion of the feedwater by-passes the extraction heaters and is heated in a stack-gas cooler. Accordingly, using information calculated in the cycle performance computer program, the actual heat transferred in the heaters was calculated and the price proportioned accordingly. For the parametric points with 31.027 and 34.472 MPa (4500 and 5000 psi) steam conditions, the price is multiplied by an additional factor of 1.15.

12.5.2.5 Gas Turbine-Generator

Prices of the gas turbine generator units were calculated on the basis of detailed proprietary information developed by the Westinghouse Gas Turbine Engine Division. This information made it possible to calculate the various components of the gas turbine as a function of such performance parameters as airflow rate, pressure ratio, enthalpy drop, and power rating. As requested, the price was broken down in the major components of compressor, combustor, turbine, and balance of plant and is presented in that form for each parametric point in the detailed account listing.

12.5.2.6 Hot Gas Piping

The low-Btu fuel gas was assumed to be generated in the gasifier at the nominal cycle pressure level and 1144°K (1600°F) and transmitted to the boilers and gas turbines in appropriate piping. The piping design chosen was a multiple layer construction with an inner liner of Incoloy, a middle layer of insulating refractory, and an outer layer of carbon steel. The outer carbon steel pipe contains the pressure forces. The insulation minimizes heat losses and allows the use of a low-temperature, low-cost outer pipe material. The inner layer of Incoloy 0.64 cm (1/4-in) thick is a lightweight liner that is inert to the corrosive effects of the high-temperature fuel gases and prevents possible shedding of the insulating material, which would damage the gas turbine downstream.

Prices were obtained from suppliers, which allowed the calculation of the prices of two pipe sizes, each operating at two pressure levels. These sizes and pressure levels covered the range expected to be encountered in the parametric study. Details of the cost breakdown of these reference pipe configurations are given in Appendix A 12.4.

For control and turndown purposes, the plant design calls for one gasifier module and corresponding fuel gas pipe for each boiler and gas turbine. The inside diameter of the pipe was calculated from continuity on the basis of fuel gas mass flow rate (determined from cycle performance calculations), the gas density (determined from the parametric operating conditions and fuel gas properties), and an assumed flow velocity. A value of 30.5 m/s (100 ft/s) was chosen; this is a nominal industry standard above which noise levels, and/or erosion rates become excessive.

The pipe price values which were calculated for a 0.91 m (3 ft) id and a 2.44 m (8 ft) id, each at 1.034 and 2.069 MPa (150 and 300 psi), were assumed to be an exponential function of pressure and diameter, which gave the following equation:

$$\text{Price} \propto (\text{pressure})^{0.3} (\text{dia}) \tag{12.6}$$

Using the continuity equation, the form of the equation becomes:

$$\text{Price} \propto (\text{pressure})^{-0.2} (\text{fuel gas flow rate})^{0.5} \tag{12.7}$$

This equation and a reference case cost permitted the calculation of hot gas piping prices for each parametric point.

For loss of load purposes, stop valves must be provided in each of the hot fuel gas lines. Because of the high operating temperatures, these valves have a significant cost. On the basis of bids as a function of size, an equation was developed for the price of the valves (total of 6) as follows:

$$\text{Price,\$} = (9227)\ (\text{gas flow rate/pressure}) \tag{12.8}$$

where gas flow rate is in pounds per second and pressure is in atmospheres.

12.5.2.7 Stack-Gas Cooler

The performance characteristics of the upper and lower stack-gas coolers were calculated by the computer code for overall cycle performance. These results, in conjunction with an assumed convection heat transfer coefficient value of 56.77 W/m^2-°K (10 Btu/hr-ft^2-°F) for finned

Curve 682230-A

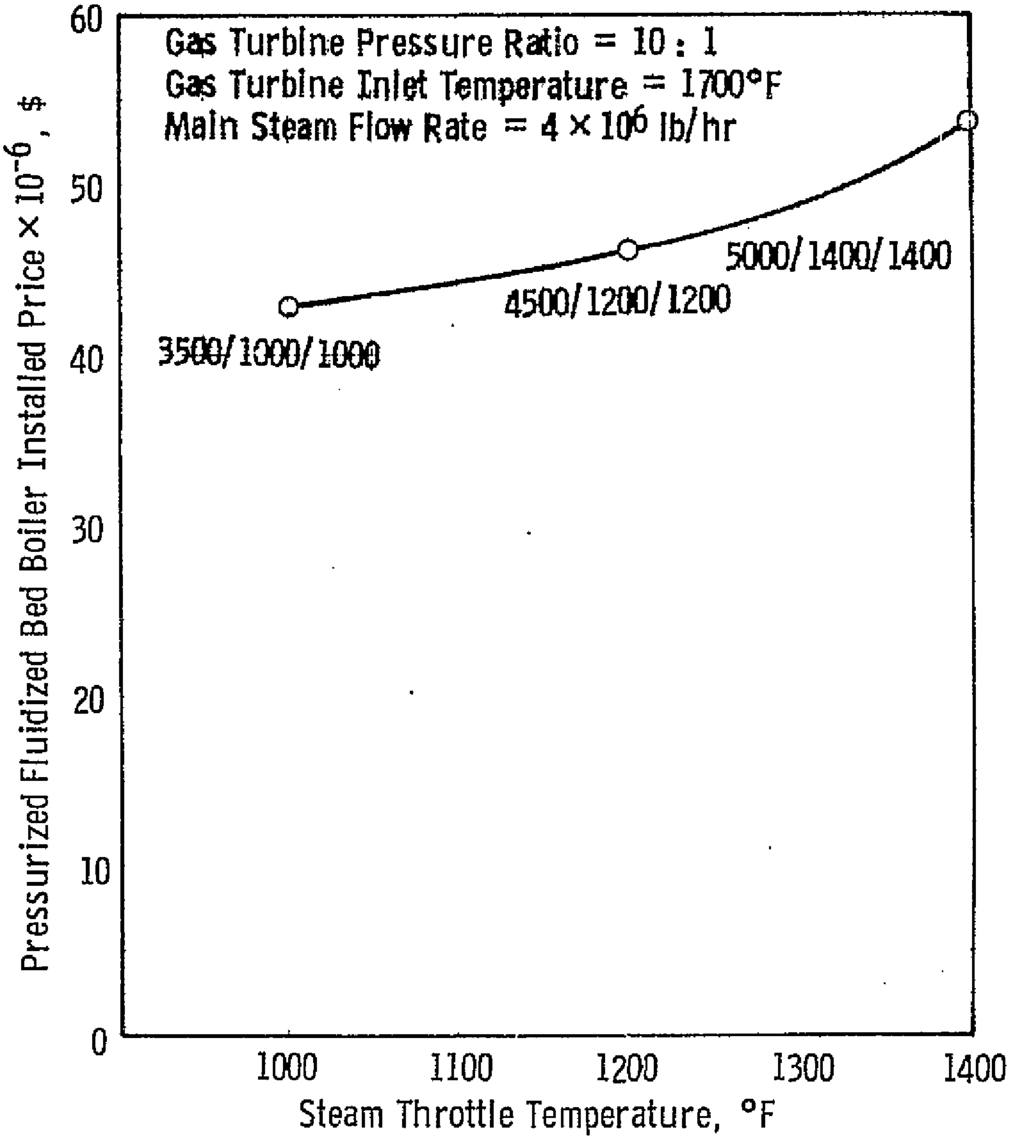

Fig. 12.39—Effect of steam turbine throttle conditions on the price of a pressurized fluidized bed boiler

tubing, allows the calculation of the total area required in the stack-gas coolers. Because of the cleanliness of the combustion gases and the relatively poor heat transfer coefficient on the gas side, an externally finned tube was used.

The major cost of the heat exchanger was that of the tubing, which was 5.1 cm (2 in) od, 3.9 mm (0.155 in) wall thickness, 9.1 m (30 ft) long, and made of A-209 TI material with a 1.3 mm (0.050 in) thick by 9.5 mm (0.375 in) high 304 SS fin welded to the tubing with a spacing of 236 fins/m (6 fins/in). Appendix A 12.5 gives a tabulation of the component costs for a heat exchanger with 46,450 m^2 (500,000 ft^2) of transfer surface. Not included is the cost of the gas turbine exhaust ducting that encases the stack-gas coolers; it is included in the cost of the gas turbine. The price of the stack-gas coolers for each parametric point was then calculated as a direct ratio of the area required for that point compared to the price for the 46,450 m^2 (500,000 ft^2) unit. Normalized, the price of the stack-gas coolers is \$46.50/m^2 (\$4.32/ft^2).

12.5.3 Pressurized Fluidized Bed Boiler System

12.5.3.1 Boiler

The basis for the design and pricing of pressurized fluidized bed boilers is described in detail in Section 4 of this report. Boilers were priced to satisfy the performance requirements defined by the cycle performance computer calculations. Figure 12.39 shows that the effect of steam temperature is similar to that of atmospheric fluidized bed boilers. Figure 12.40 shows the effect of gas-side pressure level on the boiler price. As can be seen, the price decreases as pressure increases. This is primarily the result of a reduction in particulate removal equipment cost due to the reduced volumetric flow of the hot gas to the gas turbine as the cycle pressure level increases.

Curve 682231-A

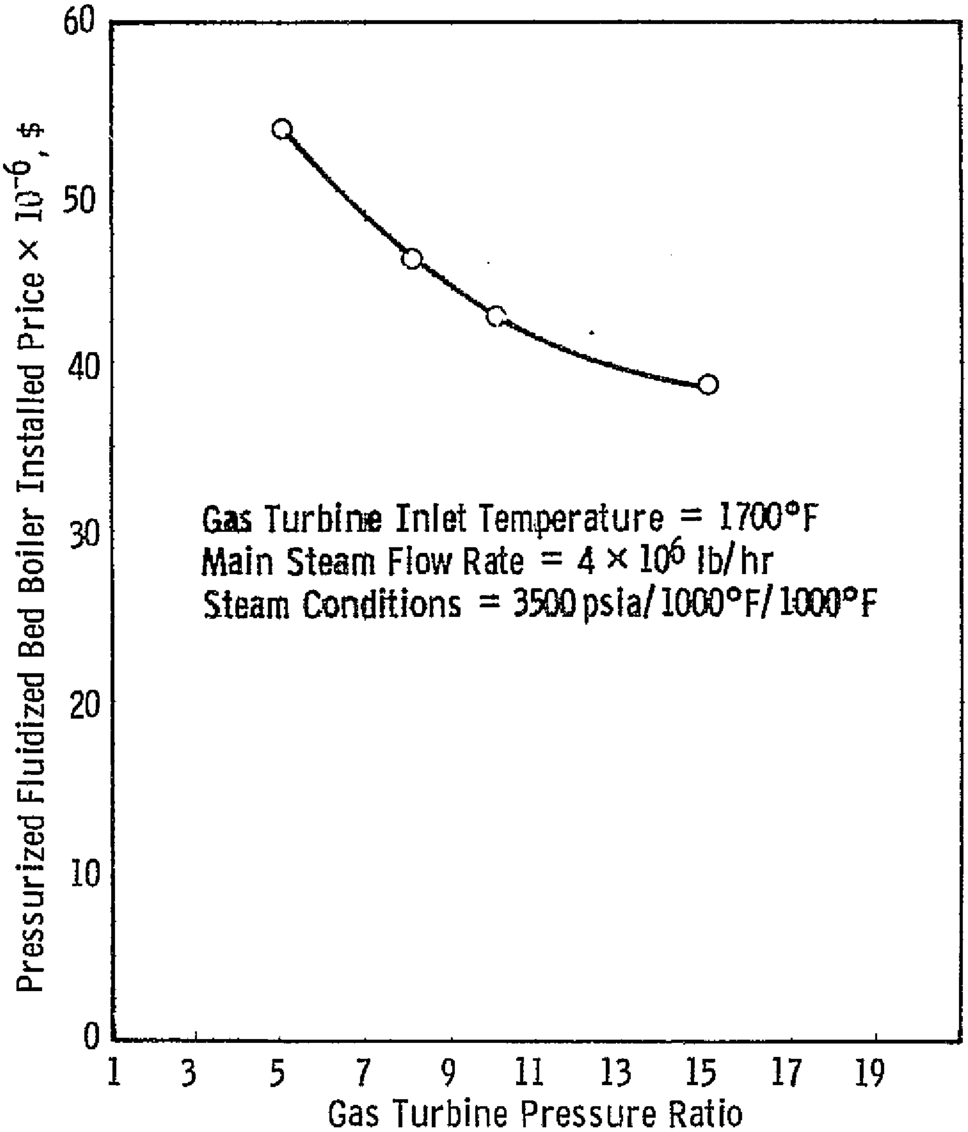

Fig. 12.40—Effect of pressurizing gas turbine pressure ratio on the price of pressurized fluidized bed boiler

12.5.3.2 Steam Turbine-Generator

The price for the steam turbine-generator units for the pressurized fluidized bed boiler system were calculated in the same manner as was done for the pressurized boiler-gasifier system.

12.5.3.3 Steam Piping

Because of the similarity between the multiple boiler arrangement of the pressurized boiler-gasified coal system and the pressurized fluidized bed boiler system, the steam piping was priced on the same basis for both.

12.5.3.4 Feedwater Heaters

Again, the pricing method used was the same as for the pressurized boiler-gasified coal system.

12.5.3.5 Gas Turbine-Generator

Using the appropriate values of airflow rate, pressure ratio, and enthalpy rise corresponding to each parametric point, the gas turbine prices were calculated as described for the pressurized boiler-gasified coal system.

12.5.3.6 Hot Gas Piping

The design of the pipe required to transport the hot combustion gases from the fluidized bed boiler to the gas turbines is essentially the same as that used to transport the hot fuel gas from the gasifier in the pressurized boiler-gasifier system. The cost is calculated for the appropriate size for each parametric point, of course, and there are a total of four pipes, two for each gas turbine. Further, no high-temperature stop valves are required since the loss of load emergency will be handled by pressure relief valves on the air inlet side of the boiler.

12.5.3.7 Stack-Gas Cooler

The design, and, therefore, the pricing method, of the stack-gas coolers is the same for the pressurized fluidized bed-boiler system and the pressurized boiler-gasifier system.

Table 12.16 - Advanced Steam Major Component Sizes & Prices (Ease Cases)

Unit	Unit Size, ft W	L(or D)	H	Unit Weight x 10^{-3}, lb	Unit Price FOB Mfg. Plant x 10^{-6},$	$/kWe*	Units Rqd.	Total Cost x 10^{-6},$
Atmospheric Boiler System								
10.1 Boiler	50	45	133	29,254	19.9	42.39	1	19.9
11.1 Stm. Turb-Gen.	19.5	125	21	995	14.3	30.46	1	14.3
Pressurized Boiler-Gasifier System								
10.1 Boiler	-	20	120	1,392	2.05	2.82	4	8.2
11.1-4 Gas Turb.-Gen	11	125	40	1,550	9.25	12.73	2	18.5
11.5 Stm. Turb.-Gen	19.5	127	21	1,050	16.4	22.56	1	16.4
13.2 Stk-Gas Cooler	30	40	67	1,690	2.0	2.75	2	4.0
Pressurized-Fluidized Bed Boiler System								
10.1 Boiler	-	18.3	116	930	10.8	15.14	4	43.3
11.1-4 Gas Turb.-Gen	11	125	40	1,550	6.55	9.18	2	13.1
11.5 Stm. Turb.-Gen	20	130	21	1,150	17.4	24.39	1	17.4
13.2 Stk.-Gas Cooler	30	40	64	1,600	1.9	2.66	2	3.8

*Note: Plant Net Power

12.5.4 Summary of Systems and Components

Table 12.16 shows the sizes, weights, and prices of the major components for the base cases of each of the advanced steam systems that were investigated.

In addition to the major components described in the foregoing material, a number of components are common to most power plants. The costs of all of the major components and the balance of plant equipment were segregated according to a standard accounts classification system and printed in tabular form by the computer. Tables 12.17 through 12.28 show these results for each of the base cases and for a recommended case for the pressurized fluidized bed system. Included in these tables are the summary sheets and the input/output sheets for each of these points.

12.6 Analysis of Overall Cost of Electricity

12.6.1 Atmospheric Furnace Systems

Figure 12.41 shows the cost of electricity for the three throttle pressure level plants as a function of steam temperature (for the cases where reheat temperature equals throttle temperature). Shown in addition to the total cost are the three major components of the cost - capital, fuel, and operating and maintenance. The results are clear. As the temperature increases in 111°K (200°F) steps, the slight decrease in the fuel cost contribution to the total cost of electricity is overwhelmed by the very large increase in the capital cost. The rate of increase is nearly the same for the 16.547 and 24.132 MPa (2400 and 3500 psi) plants but is significantly greater for the 34.472 MPa (5000 psi) plants.

At the 811°K (1000°F) temperature, the total cost of electricity produced by the 16.547 and 24.132 MPa (2400 and 3500 psi) plants is nearly the same at 6.9 mills/MJ (25 mills/kWh), while the 34.472 MPa (5000 psi) plant cost of electricity is slightly higher.

Figures 12.42 and 12.43 compare the conventional furnace plant and the fluidized bed furnace plant as a function of temperature at the

C.2

Table 12.17 ADVANCED STEAM CYCLE WITH ATM BOILER ACCOUNT LISTING
PARAMETRIC POINT NO.20

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	134.0	1000.00	.00	134000.00	.00
1. 2 CLEARING LAND	ACRE	44.7	.00	600.00	.00	26797.32
1. 3 GRADING LAND	ACRE	134.0	.00	3000.00	.00	402000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.5	120000.00	70000.00	300000.00	175000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	294612.43	294612.43
PERCENT TOTAL DIRECT COST IN ACCOUNT		1 = 2.264	ACCOUNT TOTAL,$		1303612.42	1448409.73
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	47400.0	.00	3.00	.00	142200.00
2. 2 PILING	FT	126400.0	6.50	8.50	821600.00	1074400.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		2 = 1.676	ACCOUNT TOTAL,$		821600.00	1216600.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	15800.0	70.00	80.00	1106000.00	1264000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		3 = 1.949	ACCOUNT TOTAL,$		1106000.00	1264000.00
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	765198.41	1026034.36
4. 3 SURFACE CONDENSER	FT2	255563.7	.00	.00	1201413.42	185894.59
PERCENT TOTAL DIRECT COST IN ACCOUNT		4 = 4.317	ACCOUNT TOTAL,$		3348111.81	1900428.94
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	1500.0	650.00	175.00	975000.00	262500.00
5. 2 SILOS & BUNKERS	TPH	206.8	1800.00	750.00	372275.41	155114.75
5. 3 CHIMNEY	FT	500.0	.00	.00	593557.88	890336.82
5. 4 STRUCTURAL FEATURES	EACH	1.0	374000.00	114000.00	374000.00	114000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		5 = 3.074	ACCOUNT TOTAL,$		2314833.28	1421951.56
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	3750000.0	.16	.16	600000.00	600000.00
6. 2 ADMINSTRATION	FT2	5000.0	16.00	14.00	80000.00	70000.00
6. 3 WAREHOUSE & SHOP	FT2	10000.0	12.00	8.00	120000.00	80000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT		6 = 1.275	ACCOUNT TOTAL,$		800000.00	750000.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	211.3	.00	.00	3149984.28	1465142.09
7. 2 DOLOMITE HAND. SYS	TPH	30.8	.00	.00	555629.24	330798.36
7. 3 FUEL OIL HAND. SYS	GAL	100000.0	.00	.00	20706.41	16770.11
PERCENT TOTAL DIRECT COST IN ACCOUNT		7 = 4.556	ACCOUNT TOTAL,$		3726319.91	1812710.55
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 12.17 Continued

ADVANCED STEAM CYCLE WITH ATM BOILER ACCOUNT LISTING
PARAMETRIC POINT NO. 20

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 ATM STEAM BOILER	EACH	1.0	19867000.00	9933500.00	19867000.00	9933500.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =24.511 ACCOUNT TOTAL,$					19867000.00	9933500.00
ENERGY CONVERTER						
11. 1 STEAM TURBINE-GEN	EACH	1.0	14324561.50	1007050.28	14324561.50	1007050.28
11. 2 STEAM PIPING	EACH	1.0	1700000.00	700000.00	1700000.00	700000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =14.584 ACCOUNT TOTAL,$					16024561.50	1707050.28
COUPLING HEAT EXCHANGER						
12. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = .000 ACCOUNT TOTAL,$					.00	.00
HEAT RECOVERY HEAT EXCH.						
13. 1 FEED WATER HEATER STRING		1.0	1200000.00	36000.00	1200000.00	36000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = 1.017 ACCOUNT TOTAL,$					1200000.00	36000.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	80.0	2500.00	700.00	200000.00	56000.00
14. 2 CONDENSATE POLISHING	KWE	500000.0	1.25	.30	625000.00	150000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .848 ACCOUNT TOTAL,$					825000.00	206000.00
POWER CONDITIONING						
15. 1 STD TRANSFORMER	KWE	511111.1	.00	.00	1258104.41	25362.09
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.064 ACCOUNT TOTAL,$					1258104.41	25362.09
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	548189.2	1.67	.10	915475.99	54818.92
16. 2 OTHER PUMPS	KWE	[illegible]3008.1	.88	.12	530647.16	72360.98
16. 3 MISC SERVICE SYS	KWE	548189.2	1.17	.73	641381.38	400178.12
16. 4 AUXILIARY BOILER	PPH	200000.0	4.00	.80	800000.00	160000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 2.940 ACCOUNT TOTAL,$					2887504.50	687358.01
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	750.0	3000.00	1800.00	2250000.00	1350000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 2.961 ACCOUNT TOTAL,$					2250000.00	1350000.00
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		548189.2	1.40	.17	767464.91	93192.17
18. 2 SWITCHGEAR & MCC PAN	KWE	548189.2	1.95	.45	1068968.97	246685.15
18. 3 CONDUIT,CABLES,TRAYS	FT	1950000.0	1.32	1.36	2573999.97	2651999.97
18. 4 ISOLATED PHASE BUS	FT	450.0	510.00	450.00	229500.00	202500.00
18. 5 LIGHTING & COMMUN	KWE	548189.2	.35	.43	191866.23	235721.36
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 6.795 ACCOUNT TOTAL,$					4831800.00	3430098.62

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Table 12.17 Continued

ADVANCED STEAM CYCLE WITH ATM BOILER ACCOUNT LISTING
PARAMETRIC POINT NO. 20

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	430000.00	10000.00	430000.00	10000.00
19. 2 OTHER CONTROLS	EACH	1.0	400000.00	240000.00	400000.00	240000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = .864 ACCOUNT TOTAL,$					800000.00	250000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	4.1	505836.81	126459.20	505836.81	126459.20
20. 2 DRY ASH	TPH	15.2	1103780.54	275945.16	1103780.64	275945.16
20. 3 WET SLURRY	TPH	30.8	945264.97	236316.24	945264.97	236316.24
20. 4 ONSITE DISPOSAL	ACRE	165.3	6909.30	10146.69	1149335.77	1687862.39
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 4.960 ACCOUNT TOTAL,$					3704218.16	2326582.97
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	1.0	2245305.15	1460098.34	2246305.16	1460098.34
21. 2 SCRUBBER	KWE	500000.0	28.84	13.22	14418303.62	6610558.00
21. 3 MISC STEEL & DUCTS		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 21 =20.345 ACCOUNT TOTAL,$					16664606.75	8070656.31
TOTAL DIRECT COSTS,$					83743273.00	37836708.00

TABLE 12.18-ADVANCED STEAM CYCLE WITH ATM BOILER COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.20

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 5.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	105160277.	114084029.	121579980.	137285782.	160487538.
INDIRECT COST,$	51.0	10922672.	15473785.	19296720.	27306680.	39139574.
PROF & OWNER COSTS,$	8.0	8412822.	9126722.	9726398.	10982862.	12839003.
CONTINGENCY COST,$	8.0	8412822.	9126722.	9726398.	10982862.	12839003.
SUB TOTAL,$	.0	132908593.	147811258.	160329496.	186558186.	225305116.
ESCALATION COST,$	6.5	27249207.	30304594.	32871100.	38248563.	46192542.
INTREST DURING CONST,$	10.0	31387790.	34907214.	37863530.	44057717.	53208220.
TOTAL CAPITALIZATION,$	.0	191545590.	213023056.	231064126.	268864464.	324705876.
COST OF ELEC-CAPITAL	18.0	13.07001	14.53552	15.76654	18.34583	22.15613
COST OF ELEC-FUEL	.0	8.36287	8.36297	8.36287	8.36287	8.36287
COST OF ELEC-OP & MAIN	.0	1.16570	1.16570	1.16570	1.16570	1.16570
TOTAL COST OF ELEC	.0	22.59858	24.06409	25.29511	27.87440	31.69470

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	8.00	5.00	20.00
TOTAL DIRECT COSTS,$	.0	121579980.	121579980.	121579980.	121579980.	121579980.
INDIRECT COST,$	51.0	19296720.	19296720.	19296720.	19296720.	19296720.
PROF & OWNER COSTS,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
CONTINGENCY COST,$	20.0	-6078999.	0.	9726398.	6078999.	24315996.
SUB TOTAL,$	.0	144524100.	150603098.	160329496.	156682096.	174919092.
ESCALATION COST,$	6.5	29630644.	30876973.	32871100.	32123302.	35862291.
INTREST DURING CONST,$	10.0	34130916.	35566537.	37863530.	37002158.	41309020.
TOTAL CAPITALIZATION,$	.0	208285658.	217046606.	231064126.	225807556.	252090402.
COST OF ELEC-CAPITAL	18.0	14.21226	14.81035	15.76654	15.40785	17.20126
COST OF ELEC-FUEL	.0	8.36287	8.36287	8.36287	8.36287	8.36287
COST OF ELEC-OP & MAIN	.0	1.16570	1.16570	1.16570	1.16570	1.16570
TOTAL COST OF ELEC	.0	23.74083	24.33863	25.29511	24.93643	26.72983

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	121579980.	121579980.	121579980.	121579980.	121579980.
INDIRECT COST,$	51.0	19296720.	19296720.	19296720.	19296720.	19296720.
PROF & OWNER COSTS,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
CONTINGENCY COST,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
SUB TOTAL,$	.0	160329496.	160329496.	160329496.	160329496.	160329496.
ESCALATION COST,$	.0	24861872.	32871100.	41144899.	52598683.	0.
INTREST DURING CONST,$	10.0	36540103.	37863530.	39221819.	41088125.	32373117.
TOTAL CAPITALIZATION,$	.0	221731470.	231064125.	240696212.	254016302.	192702612.
COST OF ELEC-CAPITAL	18.0	15.12973	15.76654	16.42378	17.33267	13.14896
COST OF ELEC-FUEL	.0	8.36287	8.36287	8.36287	8.36287	8.36287
COST OF ELEC-OP & MAIN	.0	1.16570	1.16570	1.16570	1.16570	1.16570
TOTAL COST OF ELEC	.0	24.65830	25.29511	25.95235	26.86124	22.67753

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	121579980.	121579980.	121579980.	121579980.	121579980.
INDIRECT COST,$	51.0	19296720.	19296720.	19296720.	19296720.	19296720.
PROF & OWNER COSTS,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
CONTINGENCY COST,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
SUB TOTAL,$	.0	160329495.	160329495.	160329496.	160329496.	160329496.
ESCALATION COST,$	6.5	32871100.	32871100.	32871100.	32871100.	32871100.
INTREST DURING CONST,$	15.0	22127921.	29894913.	37863530.	48113518.	58691702.
TOTAL CAPITALIZATION,$	.0	215328516.	223095508.	231064126.	241314114.	251892298.
COST OF ELEC-CAPITAL	18.0	14.69283	15.22293	15.76654	16.46594	17.18774
COST OF ELEC-FUEL	.0	8.36287	8.36287	8.36287	8.36287	8.36287
COST OF ELEC-OP & MAIN	.0	1.16570	1.16570	1.16570	1.16570	1.15570
TOTAL COST OF ELEC	.0	24.22140	24.75137	25.29511	25.99451	26.71631

Table 12.18-ADVANCED STEAM CYCLE WITH ATM BOILER COST OF ELECTRICITY,MILLS/KW.HR
Continued

PARAMETRIC POINT NO.20

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.30
TOTAL DIRECT COSTS,$	.0	121579980.	121579980.	121579980.	121579980.	121579980.
INDIRECT COST,$	51.0	19296720.	19296720.	19296720.	19296720.	19296720.
PROF & OWNER COSTS,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
CONTINGENCY COST,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
SUB TOTAL,$	.0	160329496.	160329496.	160329496.	160329496.	160329496.
ESCALATION COST,$	6.5	32871100.	32871100.	32871100.	32871100.	32871100.
INTREST DURING CONST,$	10.0	37863530.	37863530.	37863530.	37863530.	37863530.
TOTAL CAPITALIZATION,$	.0	231064126.	231064126.	231064126.	231064126.	231064126.
COST OF ELEC-CAPITAL	25.0	8.75919	12.61323	15.76654	18.91985	21.89797
COST OF ELEC-FUEL	.0	8.36287	8.36287	8.36287	8.36287	8.36287
COST OF ELEC-OP & MAIN	.0	1.16570	1.16570	1.16570	1.16570	1.16570
TOTAL COST OF ELEC	.0	18.28776	22.14180	25.29511	28.44842	31.42654

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	121579980.	121579980.	121579980.	121579980.	121579980.
INDIRECT COST,$	51.0	19296720.	19296720.	19296720.	19296720.	19296720.
PROF & OWNER COSTS,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
CONTINGENCY COST,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
SUB TOTAL,$	.0	160329496.	160329496.	160329496.	160329496.	160329496.
ESCALATION COST,$	6.5	32871100.	32871100.	32871100.	32871100.	32871100.
INTREST DURING CONST,$	10.0	37863530.	37863530.	37863530.	37863530.	37863530.
TOTAL CAPITALIZATION,$	.0	231064126.	231064126.	231064126.	231064126.	231064126.
COST OF ELEC-CAPITAL	18.0	15.76654	15.76654	15.76654	15.76654	15.76654
COST OF ELEC-FUEL	.0	4.91934	8.36287	14.75801	24.59668	10.03545
COST OF ELEC-OP & MAIN	.0	1.16570	1.16570	1.16570	1.16570	1.16570
TOTAL COST OF ELEC	.0	21.85157	25.29511	31.69025	41.52892	26.96768

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	121579980.	121579980.	121579980.	121579980.	121579980.
INDIRECT COST,$	51.0	19296720.	19296720.	19296720.	19296720.	19296720.
PROF & OWNER COSTS,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
CONTINGENCY COST,$	8.0	9726398.	9726398.	9726398.	9726398.	9726398.
SUB TOTAL,$	.0	160329496.	160329496.	160329496.	160329496.	160329496.
ESCALATION COST,$	6.5	32871100.	32871100.	32871100.	32871100.	32871100.
INTREST DURING CONST,$	10.0	37863530.	37863530.	37863530.	37863530.	37863530.
TOTAL CAPITALIZATION,$	.0	231064126.	231064126.	231064126.	231064126.	231064126.
COST OF ELEC-CAPITAL	18.0	85.40209	22.77389	20.49650	15.76654	12.81031
COST OF ELEC-FUEL	.0	8.36287	8.36287	8.36287	8.36287	8.36287
COST OF ELEC-OP & MAIN	.0	1.16571	1.16570	1.16570	1.16570	1.16570
TOTAL COST OF ELEC	.0	94.93067	32.30246	30.02507	25.29511	22.33688

Table 12.19 ADVANCED STEAM CYCLE WITH ATM BOILER

ACCOUNT NO	AUX POWER, MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	6.08688	16.58014	37.23961	8.98723
7	2.54180	6.92364	164.86630	.00000
10	8.50000	23.15329	.00000	.00000
14	.00000	.00000	8.65297	.00000
18	5.50000	14.98154	.00000	.00000
20	4.97926	13.56309	.00000	.00000
21	9.10391	24.79830	.00000	.00000
TOTALS	36.71185	7.92419	540.05286	9.98723

1	500.000	2	.000	3	.000	4	7868.000	5	5.000
6	590.000	7	3.500	8	2231000000.000	9	2.000	10	1.000
11	1.000	12	.000	13	1.000	14	.000	15	.000
16	2.000	17	134.000	18	3.000	19	5.000	20	2.500
21	.000	22	15800.000	23	.000	24	1500.000	25	500.000
26	3750000.000	27	5000.000	28	10000.000	29	100000.000	30	1.100
31	1.000	32	750.000	33	1.000	34	1.000	35	1.000
36	1950000.000	37	450.000	38	1.000	39	1.000	40	374000.000
41	114000.000	42	400000.000	43	10000.000	44	400000.000	45	240000.000
46	.000	47	.000	48	3.000	49	2.000	50	1.000
51	.000	52	5.350						
1	1.000	2	19600000.000	3	.500	4	1.000	5	1.000
6	1.000	7	11500000.000	8	.000	9	3800000.000	10	.000
11	1700000.000	12	700000.000	13	1.000	14	1200000.000	15	.030
16	.000	17	200000.000	18	1.000	19	1.000	20	1.000
21	.000	22	.000	23	.000	24	.000	25	.000
26	1.000	27	.000	28	.000	29	.000	30	.000

ADVANCED STEAM CYCLE WITH ATM BOILER BASE CASE INPUT

NOMINAL POWER, MWE	500.0000	NET POWER, MWE	463.2882
NOM HEAT RATE, BTU/KW-HR	9116.2804	NET HEAT RATE, BTU/KW-HR	9838.6719
OFF DESIGN HEAT RATE	8911.6262		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	2.0000
NUMBER OF TUBES/SHELL	7088.5017	TUBE LENGTH, FT	71.5510
U, BTU/HR-FT2-F	591.4577	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	51.4000
OFF DESIGN PRES, IN HG A	2.3702	LP TURBINE BLADE LEN, IN	25.0000

Table 12.20 PRESSURIZED BOILER ADVANCED STEAM SYSTEM ACCOUNT LISTING
PARAMETRIC POINT NO.18

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	151.0	1000.00	.00	151000.00	.00
1. 2 CLEARING LAND	ACRE	50.3	.00	600.00	.00	30196.98
1. 3 GRADING LAND	ACRE	151.0	.00	3000.00	.00	453000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.5	120000.00	70000.00	300000.00	175000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	327886.95	327886.95
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 = 1.394 ACCOUNT TOTAL,$					1353886.94	1536083.91
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	51750.0	.00	3.00	.00	155250.00
2. 2 PILING	FT	138000.0	6.50	8.50	897000.00	1173000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 = 1.074 ACCOUNT TOTAL,$					897000.00	1328250.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	17250.0	70.00	80.00	1207500.00	1380000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 = 1.249 ACCOUNT TOTAL,$					1207500.00	1380000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	11.0	.00	.00	1688500.00	841500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	932435.02	1250277.52
4. 3 SURFACE CONDENSER	FT2	323603.5	.00	.00	1404182.06	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 = 2.951 ACCOUNT TOTAL,$					4025117.06	2091777.52
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	1325.0	650.00	175.00	861250.00	231875.00
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 = .720 ACCOUNT TOTAL,$					1183250.00	308875.00
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	2700000.0	.16	.16	432000.00	432000.00
6. 2 ADMINISTRATION	FT2	17500.0	16.00	14.00	280000.00	245000.00
6. 3 WAREHOUSE & SHOP	FT2	17500.0	12.00	8.00	210000.00	140000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 = .839 ACCOUNT TOTAL,$					922000.00	817000.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	293.2	.00	.00	4233051.02	1887837.80
7. 2 DOLOMITE HAND. SYS	TPH	162.0	.00	.00	1239830.78	596648.20
7. 3 FUEL OIL HAND. SYS	GAL	1650000.0	.00	.00	201133.44	158292.55
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 = 4.013 ACCOUNT TOTAL,$					5674015.25	2642778.50
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	293.2	.00	.00	51138325.50	28765308.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 8 = 38.555 ACCOUNT TOTAL,$					51138325.50	28765308.00

Table 12.20 Continued PRESSURIZED BOILER ADVANCED STEAM SYSTEM ACCOUNT LISTING

PARAMETRIC POINT NO.16

ACCOUNT NO. & NAME	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
FIRING SYSTEM						
9. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 9 = .000 ACCOUNT TOTAL,$					.00	.00
VAPOR GENERATOR (FIRED)						
10. 1 PRESSURIZED BOILER	EA	1.0	8189999.94	1819999.98	8189999.94	1819999.98
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 = 4.830 ACCOUNT TOTAL,$					8189999.94	1819999.98
ENERGY CONVERTER						
11. 1 GAS TURB COMPRESSOR-SECT		1.0	1700000.00	85000.00	1700000.00	85000.00
11. 2 GAS TURB COMB SECT		1.0	1500000.00	75000.00	1500000.00	75000.00
11. 3 GAS TURB TURBINE SECTION		1.0	3700000.00	185000.00	3700000.00	185000.00
11. 4 BALANCE OF GAS TURBINE		1.0	11600000.00	1740000.00	11600000.00	1740000.00
11. 5 STEAM TURBINE		1.0	16442105.37	1112449.28	16442105.37	1112449.28
11. 6 GENERATOR		1.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =18.403 ACCOUNT TOTAL,$					34942105.00	3197449.25
COUPLING HEAT XCHANGER						
12. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = .000 ACCOUNT TOTAL,$					.00	.00
HEAT RECOVERY HEAT EXCH.						
13. 1 FEED WATER HEATER STRING		1.0	800000.00	24000.00	800000.00	24000.00
13. 2 STACK GAS COOLER		1.0	4000000.00	2300000.00	4000000.00	2300000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = 3.437 ACCOUNT TOTAL,$					4800000.00	2324000.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPH	680.1	2000.00	560.00	1360197.50	380855.30
14. 2 CONDENSATE POLISHING	KWE	576400.0	1.25	.30	720500.00	172920.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = 1.271 ACCOUNT TOTAL,$					2080697.50	553775.30
POWER CONDITIONING						
15. 1 STD TRANSFORMER	KVA	909700.0	.00	.00	2158056.94	43161.14
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.062 ACCOUNT TOTAL,$					2158056.94	43161.14
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	578603.9	1.67	.10	966268.57	57860.39
16. 2 OTHER PUMPS	KWE	821860.5	.88	.12	723237.25	98623.26
16. 3 MISC SERVICE SYS	KWE	933932.4	1.17	.73	1092700.91	681770.65
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 1.707 ACCOUNT TOTAL,$					2782206.72	838254.30
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	895.0	3000.00	1800.00	2685000.00	1611000.00
17. 2 HOT GAS PIPING	FT	1.0	1200000.00	400000.00	1200000.00	400000.00
17. 3 STEAM PIPING	TON	1.0	2000000.00	800000.00	2000000.00	800000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 4.196 ACCOUNT TOTAL,$					5885000.00	2811000.00

Table 12.20 (Continued) PRESSURIZED BOILER ADVANCED STEAM SYSTEM ACCOUNT LISTING
PARAMETRIC POINT NO.15

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		821983.5	1.40	.17	1150604.72	139716.29
18. 2 SWITCHGEAR & MCC PAN	KWE	821860.5	1.95	.45	1602628.00	369837.23
18. 3 CONDUIT,CABLES,TRAYS	FT	3140009.0	1.32	1.36	4144799.97	4270399.94
18. 4 ISOLATED PHASE BUS	FT	675.0	510.00	450.00	344250.00	303750.00
18. 5 LIGHTING & COMMUN	KWE	747145.9	.35	.43	261501.08	321272.75
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 6.229 ACCOUNT TOTAL,$					7503783.75	5404976.12
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	528000.00	12000.00	528000.00	12000.00
19. 2 OTHER CONTROLS	EACH	1.0	625000.00	375000.00	625000.00	375000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = .743 ACCOUNT TOTAL,$					1153000.00	387000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	23.4	1839500.28	459625.07	1838500.28	459625.07
20. 3 WET SLURRY	TPH	162.0	4112006.75	1028002.19	4112008.75	1028002.19
20. 4 ONSITE DISPOSAL	ACRE	535.8	5679.89	8622.84	3043318.97	4620181.31
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 7.287 ACCOUNT TOTAL,$					8993827.87	6107808.56
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	5797996.12	3768697.47	.00	.00
21. 2 SCRUBBER	KWE	.0	24.30	11.14	.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,$					144889766.00	82357495.50

Table 12.21 -
PRESSURIZED BOILER ADVANCED STEAM SYSTEM COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.16

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	180186463.	194393415.	207247260.	233131504.	271369588.
INDIRECT COST,$	51.0	18001314.	25501862.	31802322.	45003286.	64504709.
PROF & OWNER COSTS,$	8.0	14414317.	15591473.	16579781.	18650520.	21709567.
CONTINGENCY COST,$	9.0	16216781.	17540407.	18652253.	20981835.	24423263.
SUB TOTAL,$	.0	228919470.	253527156.	274281612.	317767140.	382007120.
ESCALATION COST,$	6.5	57522000.	63733165.	68950544.	79882195.	96031224.
INTREST DURING CONST,$	10.0	59529272.	75927893.	82143557.	95166872.	114405859.
TOTAL CAPITALIZATION,$	.0	354869740.	393188200.	425375712.	492816204.	592444200.
COST OF ELEC-CAPITAL	18.0	15.50395	17.17794	18.58417	21.53057	25.88320
COST OF ELEC-FUEL	.0	7.76049	7.76049	7.76049	7.76049	7.76049
COST OF ELEC-OP & MAIN	.0	1.47711	1.47711	1.47711	1.47711	1.47711
TOTAL COST OF ELEC	.0	24.74145	26.41553	27.82177	30.76817	35.12080

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	9.00	5.00	20.00
TOTAL DIRECT COSTS,$	.0	207247260.	207247260.	207247260.	207247260.	207247260.
INDIRECT COST,$	51.0	31802322.	31802322.	31802322.	31802322.	31802322.
PROF & OWNER COSTS,$	8.0	16579781.	16579781.	16579781.	16579781.	16579781.
CONTINGENCY COST,$	20.0	-10362363.	0.	18652253.	10362363.	41449451.
SUB TOTAL,$	.0	245267000.	255629362.	274281612.	265991724.	297078812.
ESCALATION COST,$	5.5	61655678.	54261630.	68950544.	56856583.	74681440.
INTREST DURING CONST,$	10.0	73454081.	76557465.	82143557.	79660849.	88971003.
TOTAL CAPITALIZATION,$	.0	380377756.	386448456.	425375712.	412519152.	460731252.
COST OF ELEC-CAPITAL	18.0	16.61826	17.32038	18.58417	18.02249	20.12882
COST OF ELEC-FUEL	.0	7.76049	7.76049	7.76049	7.76049	7.76049
COST OF ELEC-OP & MAIN	.0	1.47711	1.47711	1.47711	1.47711	1.47711
TOTAL COST OF ELEC	.0	25.85596	26.55797	27.82177	27.26008	29.36641

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	207247260.	207247260.	207247260.	207247260.	207247260.
INDIRECT COST,$	51.0	31802322.	31802322.	31802322.	31802322.	31802322.
PROF & OWNER COSTS,$	8.0	16579781.	16579781.	16579781.	16579781.	16579781.
CONTINGENCY COST,$	9.0	18652253.	18652253.	18652253.	18652253.	18652253.
SUB TOTAL,$	.0	274281612.	274281612.	274281612.	274281612.	274281612.
ESCALATION COST,$	.0	51888795.	68950544.	86743599.	111646617.	0.
INTREST DURING CONST,$	10.0	79709465.	82143557.	85696598.	90624202.	68083721.
TOTAL CAPITALIZATION,$	.0	404879068.	425375712.	446721804.	476552428.	342365332.
COST OF ELEC-CAPITAL	18.0	17.63873	18.58417	19.51676	20.82003	14.95755
COST OF ELEC-FUEL	.0	7.76049	7.76049	7.76049	7.76049	7.76049
COST OF ELEC-OP & MAIN	.0	1.47711	1.47711	1.47711	1.47711	1.47711
TOTAL COST OF ELEC	.0	26.92633	27.82177	28.75436	30.05762	24.19514

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 5.00	9.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	207247260.	207247260.	207247260.	207247260.	207247260.
INDIRECT COST,$	51.0	31802322.	31802322.	31802322.	31802322.	31802322.
PROF & OWNER COSTS,$	8.0	16579781.	16579781.	16579781.	16579781.	16579781.
CONTINGENCY COST,$	9.0	18652253.	18652253.	18652253.	18652253.	18652253.
SUB TOTAL,$	.0	274281612.	274281612.	274281612.	274281612.	274281612.
ESCALATION COST,$	6.5	68950544.	68950544.	68950544.	68950544.	68950544.
INTREST DURING CONST,$	15.0	47561783.	64554401.	82143557.	104994868.	128838686.
TOTAL CAPITALIZATION,$	.0	390793936.	407786556.	425375712.	443227024.	472070840.
COST OF ELEC-CAPITAL	18.0	17.07334	17.81572	18.58417	19.58252	20.62423
COST OF ELEC-FUEL	.0	7.76049	7.76049	7.76049	7.76049	7.76049
COST OF ELEC-OP & MAIN	.0	1.47711	1.47711	1.47711	1.47711	1.47711
TOTAL COST OF ELEC	.0	26.31093	27.05332	27.82177	28.82012	29.86183

Table 12.21 Continued -
PRESSURIZED BOILER ADVANCED STEAM SYSTEM COST OF ELECTRICITY,MILLS/KW.HR
PARAMETRIC POINT NO.19

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	16.00	21.50	25.00
TOTAL DIRECT COSTS,$	.0	207247260.	207247260.	207247260.	207247260.	207247260.
INDIRECT COST,$	51.0	31802322.	31802322.	31802322.	31802322.	31802322.
PROF & OWNER COSTS,$	8.0	16579781.	16579781.	16579781.	16579781.	16579781.
CONTINGENCY COST,$	9.0	18652253.	18652253.	18652253.	18652253.	18652253.
SUB TOTAL,$	.0	274281612.	274281612.	274281612.	274281612.	274281612.
ESCALATION COST,$	6.5	68950544.	68950544.	68950544.	68950544.	68950544.
INTREST DURING CONST,$	10.0	82143557.	82143557.	82143557.	82143557.	82143557.
TOTAL CAPITALIZATION,$	.0	425375712.	425375712.	425375712.	425375712.	425375712.
COST OF ELEC-CAPITAL	25.0	10.32454	14.96734	18.58417	22.30101	25.81135
COST OF ELEC-FUEL	.0	7.76049	7.76049	7.76049	7.76049	7.76049
COST OF ELEC-OP & MAIN	.0	1.47711	1.47711	1.47711	1.47711	1.47711
TOTAL COST OF ELEC	.0	19.56214	24.10494	27.82177	31.53860	35.04895

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	207247260.	207247260.	207247260.	207247260.	207247260.
INDIRECT COST,$	51.0	31802322.	31802322.	31802322.	31802322.	31802322.
PROF & OWNER COSTS,$	8.0	16579781.	16579781.	16579781.	16579781.	16579781.
CONTINGENCY COST,$	9.0	18652253.	18652253.	18652253.	18652253.	18652253.
SUB TOTAL,$	.0	274281612.	274281612.	274281612.	274281612.	274281612.
ESCALATION COST,$	6.5	68950544.	68950544.	68950544.	68950544.	68950544.
INTREST DURING CONST,$	10.0	82143557.	82143557.	82143557.	82143557.	82143557.
TOTAL CAPITALIZATION,$	.0	425375712.	425375712.	425375712.	425375712.	425375712.
COST OF ELEC-CAPITAL	18.0	18.58417	18.58417	18.58417	18.58417	18.58417
COST OF ELEC-FUEL	.0	4.56439	7.76049	13.69498	22.82496	9.31258
COST OF ELEC-OP & MAIN	.0	1.47711	1.47711	1.47711	1.47711	1.47711
TOTAL COST OF ELEC	.0	24.62628	27.82177	33.75626	42.88624	29.37387

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	207247260.	207247260.	207247260.	207247260.	207247260.
INDIRECT COST,$	51.0	31802322.	31802322.	31802322.	31802322.	31802322.
PROF & OWNER COSTS,$	9.0	16579781.	16579781.	16579781.	16579781.	165.3781.
CONTINGENCY COST,$	9.0	18652253.	18652253.	18652253.	18652253.	18652253.
SUB TOTAL,$	.0	274281612.	274281612.	274281612.	274281612.	274281612.
ESCALATION COST,$	6.5	68950544.	68950544.	68950544.	68950544.	68950544.
INTREST DURING CONST,$	10.0	82143557.	82143557.	82143557.	82143557.	82143557.
TOTAL CAPITALIZATION,$	.0	425375712.	425375712.	425375712.	425375712.	425375712.
COST OF ELEC-CAPITAL	19.0	100.65427	25.84391	24.15943	18.58417	15.09964
COST OF ELEC-FUEL	.0	7.76049	7.76049	7.76049	7.76049	7.76049
COST OF ELEC-OP & MAIN	.0	1.47712	1.47711	1.47711	1.47711	1.47711
TOTAL COST OF ELEC	.0	109.90188	36.08140	33.39702	27.82177	24.33724

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Table 12.22-PRESSURIZED BOILER ADVANCED STEAM SYSTEM

ACCOUNT NO	AUX POWER,MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	7.42254	35.31706	45.37844	10.47413
7	2.79907	13.50674	607.50886	.00000
14	.00000	.00000	54.26708	.00000
18	7.17990	34.64623	.00000	.00000
20	3.32197	16.02998	5.36552	.00000
TOTALS	20.72347	2.86403	1068.80029	10.47413

PRESSURIZED BOILER ADVANCED STEAM SYSTEM BASE CASE INPUT

NOMINAL POWER, MWE	744.3000	NET POWER, MWE	723.5765
NOM HEAT RATE, BTU/KW-HR	8875.7793	NET HEAT RATE, BTU/KW-HR	9129.9844
ST TURB HEAT RATE CHANGE	.9776		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	2.0000
NUMBER OF TUBES/SHELL	8537.7158	TUBE LENGTH, FT	71.5510
U, BTU/HR-FT2-F	591.4577	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	52.4000
OFF DESIGN PRES, IN HG A	2.3758	LP TURBINE BLADE LEN, IN	25.0000

1	744.300	2	.000	3	.000	4	8500.400	5	5.000
6	576.400	7	3.500	8	868600000.000	9	2.000	10	1.000
11	1.000	12	288400.000	13	1.000	14	.000	15	.000
16	2.000	17	151.000	18	3.000	19	5.000	20	2.500
21	.000	22	17250.000	23	.000	24	1325.000	25	.000
26	2700000.000	27	17500.000	28	17500.000	29	1650000.000	30	1.100
31	1.250	32	995.000	33	.000	34	1.100	35	1.100
36	3140000.000	37	675.000	38	1.000	39	1.000	40	322000.000
41	77000.000	42	528000.000	43	12000.000	44	525000.000	45	375000.000
46	1.000	47	.000	48	3.000	49	2.000	50	.000
51	.500	52	3.750						
1	1.000	2	630000.000	3	1400000.000	4	1.000	5	1.000
5	1.000	7	1.000	8	1.000	9	1.000	10	1700000.000
11	.050	12	1500000.000	13	.050	14	3700000.000	15	.050
15	11600000.000	17	.150	18	13200000.000	19	.000	20	4400000.000
21	.000	22	1.000	23	1.000	24	800000.000	25	.030
26	4000000.000	27	2300000.000	28	1.000	29	1.000	30	1200000.000
31	400000.000	32	2000000.000	33	800000.000	34	1.000	35	.000
35	.000	37	.000	38	.000	39	.000	40	.000
41	.000	42	.000	43	1.000	44	1.000	45	.000
45	.000	47	.000	48	.000	49	1.000	50	1.000

Table 12.23–FLUIDIZED BED BOILER ADVANCED STEAM SYS ACCOUNT LISTING
PARAMETRIC POINT NO. 7

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	136.0	1000.00	.00	136000.00	.00
1. 2 CLEARING LAND	ACRE	45.3	.00	500.00	.00	27197.28
1. 3 GRADING LAND	ACRE	136.0	.00	3000.00	.00	408000.00
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.5	120000.00	70000.00	300000.00	175000.00
1. 6 SIDING R R TRACK	MILE	.0	125000.00	60000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	298561.39	298561.39
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 = 1.755 ACCOUNT TOTAL,$					1309561.39	1458758.66
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	54600.0	.00	3.00	.00	163800.00
2. 2 PILING	FT	145600.0	6.50	8.50	946400.00	1237600.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 = 1.488 ACCOUNT TOTAL,$					946400.00	1401400.00
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	18200.0	70.00	80.00	1274000.00	1456000.00
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 = 1.731 ACCOUNT TOTAL,$					1274000.00	1456000.00
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	11.0	.00	.00	1688500.00	841500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	940486.20	1261073.14
4. 3 SURFACE CONDENSER	FT2	326397.7	.00	.00	1413943.84	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 = 3.896 ACCOUNT TOTAL,$					4042930.03	2102573.12
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	1550.0	650.00	175.00	1007500.00	271250.00
5. 2 SILOS & BUNKERS	TPH	.0	1800.00	750.00	.00	.00
5. 3 CHIMNEY	FT	400.0	.00	.00	435070.92	652606.38
5. 4 STRUCTURAL FEATURES	EACH	1.0	322000.00	77000.00	322000.00	77000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 5 = 1.753 ACCOUNT TOTAL,$					1764570.92	1000856.38
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	3375000.0	.16	.16	540000.00	540000.00
6. 2 ADMINSTRATION	FT2	10000.0	16.00	14.00	160000.00	140000.00
6. 3 WAREHOUSE & SHOP	FT2	17500.0	12.00	8.00	210000.00	140000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 = 1.097 ACCOUNT TOTAL,$					910000.00	820000.00
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	292.5	.00	.00	4224218.06	1884458.42
7. 2 DOLOMITE HAND. SYS	TPH	158.3	.00	.00	1214155.87	586034.72
7. 3 FUEL OIL HAND. SYS	GAL	1000000.0	.00	.00	134000.00	106000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 = 5.166 ACCOUNT TOTAL,$					5572373.87	2576493.09
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 12.23 - FLUIDIZED BED BOILER ADVANCED STEAM SYS ACCOUNT LISTING
Continued
PARAMETRIC POINT NO. 7

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 FLUIDIZED BED BOILER	EA	1.0	25952000.00	17301000.00	25952000.00	17301000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =27.420 ACCOUNT TOTAL,$					25952000.00	17301000.00
ENERGY CONVERTER						
11. 1 GAS TURB COMPRESSOR-SECT		1.0	1700000.00	85000.00	1700000.00	85000.00
11. 2 GAS TURB COMB SECT		1.0	900000.00	45000.00	900000.00	45000.00
11. 3 GAS TURB TURBINE SECTION		1.0	3200000.00	160000.00	3200000.00	160000.00
11. 4 BALANCE OF GAS TURBINE		1.0	7300000.00	1095000.00	7300000.00	1095000.00
11. 5 STEAM TURBINE		1.0	17438596.50	1158367.97	17438596.50	1158367.97
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =20.972 ACCOUNT TOTAL,$					30538596.50	2543367.94
COUPLING HEAT EXCHANGER						
12. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = .000 ACCOUNT TOTAL,$					.00	.00
HEAT RECOVERY HEAT EXCH.						
13. 1 FEED WATER HEATER STRING		1.0	900000.00	27000.00	900000.00	27000.00
13. 2 STACK GAS COOLER		1.0	3800000.00	2200000.00	3800000.00	2200000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = 4.391 ACCOUNT TOTAL,$					4700000.00	2227000.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	98.7	2500.00	700.00	246839.99	69115.20
14. 2 CONDENSATE POLISHING	KWE	617100.0	1.25	.30	771374.98	185130.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .897 ACCOUNT TOTAL,$					1018214.98	254245.20
POWER CONDITIONING						
15. 1 STD TRANSFORMER	KVA	893933.3	.00	.00	2667639.28	53352.79
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.725 ACCOUNT TOTAL,$					2667639.28	53352.79
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	621569.1	1.67	.10	1038020.44	62156.91
16. 2 OTHER PUMPS	KWE	810365.6	.88	.12	713122.60	97243.99
16. 3 MISC SERVICE SYS	KWE	920871.1	1.17	.73	1077419.23	672235.92
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 2.320 ACCOUNT TOTAL,$					2828562.25	831636.82
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	1040.0	3000.00	1800.00	3120000.00	1872000.00
17. 2 HOT GAS PIPING	FT	1.0	900000.00	600000.00	900000.00	600000.00
17. 3 STEAM PIPING	TON	1.0	2000000.00	800000.00	2000000.00	800000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 5.891 ACCOUNT TOTAL,$					6028000.00	3272000.00

Table 12.23 -FLUIDIZED BED BOILER ADVANCED STEAM SYS   ACCOUNT LISTING
Continued
PARAMETRIC POINT NO. 7

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		884036.3	1.40	.17	1237650.81	150286.17
18. 2 SWITCHGEAR & MCC PAN	KWE	884036.3	1.95	.45	1723870.78	397816.33
18. 3 CONDUIT,CABLES,TRAYS	FT	3640000.0	1.32	1.36	4804799.94	4950399.94
18. 4 ISOLATED PHASE BUS	FT	675.0	510.00	450.00	344250.00	303750.00
18. 5 LIGHTING & COMMUN	KWE	736696.9	.35	.43	257843.92	316779.67
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 9.194 ACCOUNT TOTAL,$					8368415.37	6119032.06
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	528000.00	12000.00	529000.00	12000.00
19. 2 OTHER CONTROLS	EACH	1.0	565000.00	400000.00	565000.00	400000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = 1.017 ACCOUNT TOTAL,$					1193000.00	412000.00
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	28.7	1803525.59	450881.40	1803525.59	450881.40
20. 3 WET SLURRY	TPH	159.3	4017638.69	1004409.67	4017638.69	1004409.67
20. 4 ONSITE DISPOSAL	ACRE	523.9	5709.18	8660.44	2991293.12	4537585.87
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 3.386 ACCOUNT TOTAL,$					8812457.37	5992876.94
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	5787524.25	3761890.75	.00	.00
21. 2 SCRUBBER	KWE	.0	24.56	11.26	.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,$					107318719.00	19822591.50

Table 12.24 -
FLUIDIZED BED BOILER ADVANCED STEAM SYS   COST OF ELECTRICITY, MILLS/KW.HR
PARAMETRIC POINT NO. 7

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 6.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	136120184.	147870796.	157741310.	178422386.	208973974.
INDIRECT COST,$	51.0	14392748.	20375559.	25409521.	35956870.	51538179.
PROF & OWNER COSTS,$	8.0	10889615.	11829664.	12619305.	14273791.	16717918.
CONTINGENCY COST,$	9.0	10889615.	11829664.	12619305.	14273791.	16717918.
SUB TOTAL,$	.0	172282158.	191905678.	208389438.	242926836.	293947984.
ESCALATION COST,$	5.5	35321661.	39344917.	42724453.	49805385.	60265852.
INTREST DURING CONST,$	10.0	40686280.	45320584.	49213401.	57369778.	69418970.
TOTAL CAPITALIZATION,$	.0	249290098.	276571176.	300327289.	350101996.	423632804.
COST OF ELEC-CAPITAL	18.0	11.05366	12.31270	13.37031	15.58623	18.85976
COST OF ELEC-FUEL	.0	7.72648	7.72648	7.72648	7.72648	7.72648
COST OF ELEC-OP & MAIN	.0	1.77972	1.77972	1.77972	1.77972	1.77972
TOTAL COST OF ELEC	.0	20.55985	21.81890	22.87650	25.09243	28.36596

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	8.00	5.00	20.00
TOTAL DIRECT COSTS,$	.0	157741310.	157741310.	157741310.	157741310.	157741310.
INDIRECT COST,$	51.0	25409521.	25409521.	25409521.	25409521.	25409521.
PROF & OWNER COSTS,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
CONTINGENCY COST,$	20.0	-7887065.	0.	12619305.	7887065.	31548262.
SUB TOTAL,$	.0	187883070.	195770134.	208389438.	203657198.	227318394.
ESCALATION COST,$	6.5	38520193.	40137216.	42724453.	41754239.	46605309.
INTREST DURING CONST,$	10.0	44370602.	46233217.	49213401.	48095832.	53683677.
TOTAL CAPITALIZATION,$	.0	270773864.	282140564.	300327288.	293507268.	327607376.
COST OF ELEC-CAPITAL	18.0	12.05461	12.56065	13.37031	13.06669	14.58479
COST OF ELEC-FUEL	.0	7.72648	7.72648	7.72648	7.72648	7.72648
COST OF ELEC-OP & MAIN	.0	1.77972	1.77972	1.77972	1.77972	1.77972
TOTAL COST OF ELEC	.0	21.56081	22.06685	22.87650	22.57288	24.09099

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	157741310.	157741310.	157741310.	157741310.	157741310.
INDIRECT COST,$	51.0	25409521.	25409521.	25409521.	25409521.	25409521.
PROF & OWNER COSTS,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
CONTINGENCY COST,$	9.0	12619305.	12619305.	12619305.	12619305.	12619305.
SUB TOTAL,$	.0	208389438.	208389438.	208389438.	208389438.	208389438.
ESCALATION COST,$	.0	32314401.	42724453.	53478385.	68365524.	0.
INTREST DURING CONST,$	10.0	47493266.	49213401.	50978847.	53404592.	42077196.
TOTAL CAPITALIZATION,$	.0	288197104.	300327288.	312846668.	330159552.	250466634.
COST OF ELEC-CAPITAL	18.0	12.83028	13.37031	13.92766	14.69841	11.15055
COST OF ELEC-FUEL	.0	7.72648	7.72649	7.72649	7.72648	7.72648
COST OF ELEC-OP & MAIN	.0	1.77972	1.77972	1.77972	1.77972	1.77972
TOTAL COST OF ELEC	.0	22.33648	22.87650	23.43386	24.20461	20.65675

ACCOUNT	RATE, PERCENT	INT DURING CONST, PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	157741310.	157741310.	157741310.	157741310.	157741310.
INDIRECT COST,$	51.0	25409521.	25409521.	25409521.	25409521.	25409521.
PROF & OWNER COSTS,$	9.0	12619305.	12619305.	12619305.	12619305.	12619305.
CONTINGENCY COST,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
SUB TOTAL,$	.0	208389438.	208389439.	208389438.	208389438.	208389438.
ESCALATION COST,$	6.5	42724453.	42724453.	42724453.	42724453.	42724453.
INTREST DURING CONST,$	15.0	28760927.	38856132.	49213401.	62535898.	76284970.
TOTAL CAPITALIZATION,$	.0	279874816.	289970020.	300327288.	313649788.	327398860.
COST OF ELEC-CAPITAL	18.0	12.45978	12.90921	13.37031	13.96341	14.57551
COST OF ELEC-FUEL	.0	7.72648	7.72648	7.72648	7.72648	7.72648
COST OF ELEC-OP & MAIN	.0	1.77972	1.77972	1.77972	1.77972	1.77972
TOTAL COST OF ELEC	.0	21.96598	22.41541	22.87650	23.46961	24.08171

Table 12.24 continued –
FLUIDIZED BED BOILER ADVANCED STEAM SYS   COST OF ELECTRICITY-MILLS/KW.HR
PARAMETRIC POINT NO. 7

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	157741310.	157741310.	157741310.	157741310.	157741310.
INDIRECT COST,$	51.0	25409521.	25409521.	25409521.	25409521.	25409521.
PROF & OWNER COSTS,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
CONTINGENCY COST,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
SUB TOTAL,$	.0	208389438.	208389438.	208389438.	208389438.	208389438.
ESCALATION COST,$	6.5	42724453.	42724453.	42724453.	42724453.	42724453.
INTREST DURING CONST,$	10.0	49213401.	49213401.	49213401.	49213401.	49213401.
TOTAL CAPITALIZATION,$	.0	300327289.	300327289.	300327288.	300327289.	300327288.
COST OF ELEC-CAPITAL	25.0	7.42755	10.69624	13.37031	16.04437	18.56987
COST OF ELEC-FUEL	.0	7.72649	7.72648	7.72648	7.72648	7.72648
COST OF ELEC-OP & MAIN	.0	1.77972	1.77972	1.77972	1.77972	1.77972
TOTAL COST OF ELEC	.0	15.93415	20.20244	22.87650	25.55057	28.07607

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	157741310.	157741310.	157741310.	157741310.	157741310.
INDIRECT COST,$	51.0	25409521.	25409521.	25409521.	25409521.	25409521.
PROF & OWNER COSTS,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
CONTINGENCY COST,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
SUB TOTAL,$	.0	208389439.	208389439.	208389438.	208389438.	208389438.
ESCALATION COST,$	6.5	42724453.	42724453.	42724453.	42724453.	42724453.
INTREST DURING CONST,$	10.0	49213401.	49213401.	49213401.	49213401.	49213401.
TOTAL CAPITALIZATION,$	.0	300327288.	300327288.	300327288.	300327288.	300327288.
COST OF ELEC-CAPITAL	18.0	13.37031	13.37031	13.37031	13.37031	13.37031
COST OF ELEC-FUEL	.0	4.54499	7.72648	13.63497	22.72495	9.27178
COST OF ELEC-OP & MAIN	.0	1.77972	1.77972	1.77972	1.77972	1.77972
TOTAL COST OF ELEC	.0	19.69501	22.87650	28.78499	37.87497	24.42180

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	65.00	80.00
TOTAL DIRECT COSTS,$	.0	157741310.	157741310.	157741310.	157741310.	157741310.
INDIRECT COST,$	51.0	25409521.	25409521.	25409521.	25409521.	25409521.
PROF & OWNER COSTS,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
CONTINGENCY COST,$	8.0	12619305.	12619305.	12619305.	12619305.	12619305.
SUB TOTAL,$	.0	208389438.	208389438.	208389438.	208389438.	208389438.
ESCALATION COST,$	6.5	42724453.	42724453.	42724453.	42724453.	42724453.
INTREST DURING CONST,$	10.0	49213401.	49213401.	49213401.	49213401.	49213401.
TOTAL CAPITALIZATION,$	.0	300327288.	300327288.	300327288.	300327288.	300327288.
COST OF ELEC-CAPITAL	18.0	72.42249	19.31266	17.38140	13.37031	10.86337
COST OF ELEC-FUEL	.0	7.72648	7.72648	7.72648	7.72648	7.72648
COST OF ELEC-OP & MAIN	.0	1.77973	1.77972	1.77972	1.77972	1.77972
TOTAL COST OF ELEC	.0	91.92870	28.81886	26.88760	22.87650	20.36957

Table 12.25 - FLUIDIZED BED BOILER ADVANCED STEAM SYS

ACCOUNT NO	AUX POWER, MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	7.47122	35.04653	45.77027	10.52312
7	2.79259	13.09965	846.82170	.00000
8	.38032	1.78405	.00000	.00000
14	.00000	.00000	10.67949	.00000
18	7.35960	34.52292	.00000	.00000
20	3.31428	15.54594	5.24238	.00000
TOTALS	21.31801	3.00219	1263.74336	10.52312

FLUIDIZED BED BOILER ADVANCED STEAM SYS		BASE CASE INPUT	
NOMINAL POWER, MWE	731.4000	NET POWER, MWE	710.0820
NOM HEAT RATE, BTU/KW-HR	9825.0344	NET HEAT RATE, BTU/KW-HR	9089.9786
ST TURB HEAT RATE CHANGE	8628.9789		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	2.0000
NUMBER OF TUBES/SHELL	8712.2999	TUBE LENGTH, FT	71.5510
U, BTU/HR-FT2-F	591.4577	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	51.4000
OFF DESIGN PRES, IN HG A	2.3935	LP TURBINE BLADE LEN, IN	25.0000

1	731.400	2	.000	3	.000	4	8630.300	5	5.000
6	617.100	7	3.500	8	876100000.000	9	2.000	10	1.000
11	1.000	12	132.800	13	1.000	14	.000	15	.000
16	2.000	17	136.000	18	3.000	19	5.000	20	2.500
21	.000	22	13200.000	23	.000	24	1550.000	25	400.000
26	3375000.000	27	10000.000	28	17500.000	29	1000000.000	30	1.100
31	1.250	32	1040.000	33	.000	34	1.200	35	1.200
36	3640000.000	37	675.000	38	1.000	39	1.000	40	322000.000
41	77000.000	42	529000.000	43	12000.000	44	655000.000	45	400000.000
46	.000	47	.000	48	3.000	49	2.000	50	.000
51	.500	52	5.350						
1	1.000	2	25952000.000	3	17301000.000	4	1.000	5	1.000
6	1.000	7	1.000	8	1.000	9	1700000.000	10	.050
11	900000.000	12	.050	13	3200000.000	14	.050	15	7300000.000
16	.150	17	14000000.000	18	.000	19	1.000	20	1.000
21	900000.000	22	.030	23	3800000.000	24	2200000.000	25	1.000
25	1.000	27	900000.000	28	600000.000	29	2000000.000	30	800000.000
31	.000	32	.000	33	.000	34	1.000	35	.000
35	.000	37	.000	38	.000	39	.000	40	.000
41	.000	42	.000	43	1.000	44	1.000	45	.000
46	.000	47	.000	48	.000	49	2.000	50	1.000

Table 12.26 - FLUIDIZED BED BOILER ADVANCED STEAM SYS ACCOUNT LISTING
PARAMETRIC POINT NO.31

ACCOUNT NO. & NAME,	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
SITE DEVELOPMENT						
1. 1 LAND COST	ACRE	138.1	1000.00	.00	138095.45	.00
1. 2 CLEARING LAND	ACRE	45.0	.00	600.00	.00	27616.34
1. 3 GRADING LAND	ACRE	138.1	.00	3000.00	.00	414286.46
1. 4 ACCESS RAILROAD	MILE	5.0	115000.00	110000.00	575000.00	550000.00
1. 5 LOOP RAILROAD TRACK	MILE	2.5	120000.00	70000.00	303692.26	177153.82
1. 6 SIDING R R TRACK	MILE	.0	125000.00	80000.00	.00	.00
1. 7 OTHER SITE COSTS	ACRE	.0	.00	.00	302688.79	302688.79
PERCENT TOTAL DIRECT COST IN ACCOUNT 1 = 1.724 ACCOUNT TOTAL,$					1319476.52	1471745.39
EXCAVATION & PILING						
2. 1 COMMON EXCAVATION	YD3	56145.1	.00	3.00	.00	168435.25
2. 2 PILING	FT	149720.2	6.50	8.50	973181.42	1272621.86
PERCENT TOTAL DIRECT COST IN ACCOUNT 2 = 1.491 ACCOUNT TOTAL,$					973181.42	1441057.09
PLANT ISLAND CONCRETE						
3. 1 PLANT IS. CONCRETE	YD3	18715.3	70.00	80.00	1310051.91	1497202.19
3. 2 SPECIAL STRUCTURES	YD3	.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 3 = 1.734 ACCOUNT TOTAL,$					1310051.91	1497202.19
HEAT REJECTION SYSTEM						
4. 1 COOLING TOWERS	EACH	11.0	.00	.00	1688500.00	841500.00
4. 2 CIRCULATING H2O SYS	EACH	1.0	.00	.00	940808.25	1261504.95
4. 3 SURFACE CONDENSER	FT2	326509.4	.00	.00	1414334.31	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 4 = 3.796 ACCOUNT TOTAL,$					4043642.56	2103004.94
STRUCTURAL FEATURES						
5. 1 STAT. STRUCTURAL ST.	TON	1582.9	650.00	175.00	1028906.41	277013.26
5. 2 SILOS & BUNKERS	TPH	.0	1800.00	750.00	.00	.00
5. 3 CHIMNEY	FT	403.1	.00	.00	439491.03	659236.55
5. 4 STRUCTURAL FEATURES	EACH	1.0	326961.38	78186.42	326961.38	78186.42
PERCENT TOTAL DIRECT COST IN ACCOUNT 5 = 1.735 ACCOUNT TOTAL,$					1795358.81	1014436.22
BUILDINGS						
6. 1 STATION BUILDINGS	FT3	3455944.0	.16	.16	552951.03	552951.03
6. 2 ADMINSTRATION	FT2	10239.8	16.00	14.00	163837.34	143357.68
6. 3 WAREHOUSE & SHOP	FT2	17837.7	12.00	8.00	214052.37	142701.58
PERCENT TOTAL DIRECT COST IN ACCOUNT 6 = 1.093 ACCOUNT TOTAL,$					930840.74	839010.28
FUEL HANDLING & STORAGE						
7. 1 COAL HANDLING SYS	TPH	297.9	.00	.00	4293356.62	1910882.91
7. 2 DOLOMITE HAND. SYS	TPH	161.2	.00	.00	1234028.20	594252.29
7. 3 FUEL OIL HAND. SYS	GAL	1031053.5	.00	.00	137364.92	108627.81
PERCENT TOTAL DIRECT COST IN ACCOUNT 7 = 5.113 ACCOUNT TOTAL,$					5664749.69	2613763.00
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 12.26 FLUIDIZED BED BOILER ADVANCED STEAM SYS ACCOUNT LISTING
Continued
PARAMETRIC POINT NO.31

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 FLUIDIZED BED BOILER	EA	1.0	26615000.00	17744000.00	26615000.00	17744000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 10 =27.397 ACCOUNT TOTAL,$					26615000.00	17744000.00
ENERGY CONVERTER						
11. 1 GAS TURB COMPRESSOR-SECT		1.0	1700000.00	85000.00	1700000.00	85000.00
11. 2 GAS TURB COMB. SECT		1.0	900000.00	45000.00	900000.00	45000.00
11. 3 GAS TURB TURBINE SECTION		1.0	3400000.00	170000.00	3400000.00	170000.00
11. 4 BALANCE OF GAS TURBINE		1.0	9300000.00	1245000.00	9300000.00	1245000.00
11. 5 STEAM TURBINE		1.0	17438596.50	1158317.39	17438596.50	1158317.39
PERCENT TOTAL DIRECT COST IN ACCOUNT 11 =21.272 ACCOUNT TOTAL,$					31738596.50	2703317.37
COUPLING HEAT EXCHANGER						
12. 1		.0	.00	.00	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 12 = .000 ACCOUNT TOTAL,$					.00	.00
HEAT RECOVERY HEAT EXCH.						
13. 1 FEED WATER HEATER STRING		1.0	900000.00	27000.00	900000.00	27000.00
13. 2 STACK GAS COOLER		1.0	4000000.00	2300000.00	4000000.00	2300000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 13 = 4.463 ACCOUNT TOTAL,$					4900000.00	2327000.00
WATER TREATMENT						
14. 1 DEMINERALIZER	GPM	98.8	2500.00	700.00	246879.99	69126.40
14. 2 CONDENSATE POLISHING	KWE	617200.0	1.25	.30	771499.98	185160.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 14 = .786 ACCOUNT TOTAL,$					1018379.98	254286.40
POWER CONDITIONING						
15. 1 STD TRANSFORMER	KVA	928766.6	.00	.00	2709787.59	54195.75
PERCENT TOTAL DIRECT COST IN ACCOUNT 15 = 1.707 ACCOUNT TOTAL,$					2709787.59	54195.75
AUXILIARY MECH EQUIPMENT						
16. 1 BOILER FEED PUMP &DR.	KWE	617143.4	1.67	.10	1030629.54	61714.34
16. 2 OTHER PUMPS	KWE	855859.0	.88	.12	753155.95	102703.08
16. 3 MISC SERVICE SYS	KWE	972567.1	1.17	.73	1137903.50	709973.97
16. 4 AUXILIARY BOILER	PPH	.0	4.00	.80	.00	.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 16 = 2.344 ACCOUNT TOTAL,$					2921688.97	874391.39
PIPE & FITTINGS						
17. 1 CONVENTIONAL PIPING	TON	1064.9	3000.00	1800.00	3194828.19	1916896.91
17. 2 HOT GAS PIPING	FT	1.0	900000.00	600000.00	900000.00	600000.00
17. 3 STEAM PIPING	TON	1.0	2000000.00	800000.00	2000000.00	800000.00
PERCENT TOTAL DIRECT COST IN ACCOUNT 17 = 5.813 ACCOUNT TOTAL,$					6094828.19	3316896.91

Table 12.26 FLUIDIZED BED BOILER ADVANCED STEAM SYS ACCOUNT LISTING
Continued
PARAMETRIC POINT NO.31

ACCOUNT NO. & NAME.	UNIT	AMOUNT	MAT $/UNIT	INS $/UNIT	MAT COST,$	INS COST,$
AUXILIARY ELEC EQUIPMENT						
18. 1 MISC MOTERS,ETC		933664.4	1.40	.17	1307130.17	158722.95
18. 2 SWITCHGEAR & MCC PAN	KWE	933664.4	1.95	.45	1820645.61	420148.98
18. 3 CONDUIT,CABLES,TRAYS	FT	3727299.6	1.32	1.36	4920035.37	5069127.37
18. 4 ISOLATED PHASE BUS	FT	683.3	510.00	450.00	348486.87	307488.41
18. 5 LIGHTING & COMMUN	KWE	759830.4	.35	.43	265940.63	326727.05
PERCENT TOTAL DIRECT COST IN ACCOUNT 18 = 9.233 ACCOUNT TOTAL,$					8662238.50	6282214.62
CONTROL, INSTRUMENTATION						
19. 1 COMPUTER	EACH	1.0	533070.06	12115.23	538188.81	12231.56
19. 2 OTHER CONTROLS	EACH	1.0	573184.52	404923.02	681469.77	409906.63
PERCENT TOTAL DIRECT COST IN ACCOUNT 19 = 1.014 ACCOUNT TOTAL,$					1219658.58	422138.19
PROCESS WASTE SYSTEMS						
20. 1 BOTTOM ASH	TPH	.0	.00	.00	.00	.00
20. 2 DRY ASH	TPH	29.2	1830610.44	457652.61	1830610.44	457652.61
20. 3 WET SLURRY	TPH	161.2	4390652.36	1022665.52	4090662.06	1022665.52
20. 4 ONSITE DISPOSAL	ACRE	533.5	5685.61	8630.20	3033083.12	4603927.81
PERCENT TOTAL DIRECT COST IN ACCOUNT 20 = 9.288 ACCOUNT TOTAL,$					8954355.62	6084245.94
STACK GAS CLEANING						
21. 1 PRECIPITATOR	EACH	.0	5569411.44	3815117.41	.00	.00
21. 2 SCRUBBER	KWE	.0	24.36	11.17	.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,$					110871830.00	51042903.00

Table 12.27 -
FLUIDIZED BED BOILER ADVANCED STEAM SYS   COST OF ELECTRICITY,MILLS/KW-HR
PARAMETRIC POINT NO.31

ACCOUNT	RATE, PERCENT	LABOR RATE, $/HR 5.00	8.50	10.60	15.00	21.50
TOTAL DIRECT COSTS,$	.0	139764038.	151802458.	161914732.	183102352.	214402244.
INDIRECT COST,$	51.0	14735073.	20974620.	25031890.	35937566.	52800510.
PROF & OWNER COSTS,$	8.0	11181143.	12144197.	12953178.	14648188.	17152179.
CONTINGENCY COST,$	9.0	11228028.	12195142.	13007517.	14709637.	17224133.
SUB TOTAL,$	.0	176908214.	197016414.	213907306.	249297742.	301579064.
ESCALATION COST,$	6.5	35539844.	40593130.	44181892.	51491677.	62290222.
INTREST DURING CONST,$	10.0	42137106.	46926604.	50949782.	59379298.	71831991.
TOTAL CAPITALIZATION,$	.0	255595164.	284636143.	309038980.	360169712.	435701272.
COST OF ELEC-CAPITAL	18.0	10.94326	12.18712	13.23196	15.42116	18.65520
COST OF ELEC-FUEL	.0	7.56605	7.56605	7.56605	7.56605	7.56605
COST OF ELEC-OP & MAIN	.0	1.73574	1.73574	1.73574	1.73574	1.73574
TOTAL COST OF ELEC	.0	20.24504	21.48891	22.53375	24.72294	27.95698

ACCOUNT	RATE, PERCENT	CONTINGENCY, PERCENT -5.00	.00	8.03	5.00	20.00
TOTAL DIRECT COSTS,$	.0	161914732.	161914732.	161914732.	161914732.	161914732.
INDIRECT COST,$	51.0	26031880.	26031880.	26031880.	26031880.	26031880.
PROF & OWNER COSTS,$	8.0	12953179.	12953178.	12953178.	12953178.	12953178.
CONTINGENCY COST,$	20.0	-8095737.	0.	13007517.	8095737.	32382946.
SUB TOTAL,$	.0	192804054.	200999790.	213907306.	208995526.	233282736.
ESCALATION COST,$	6.5	39823080.	41495230.	44181892.	43167379.	48183827.
INTREST DURING CONST,$	10.0	45923277.	47851579.	50949782.	49779864.	55564743.
TOTAL CAPITALIZATION,$	.0	278550408.	290246588.	309038980.	301942768.	337031300.
COST OF ELEC-CAPITAL	18.0	11.92655	12.42734	13.23196	12.92813	14.43049
COST OF ELEC-FUEL	.0	7.56605	7.56605	7.56605	7.56605	7.56605
COST OF ELEC-OP & MAIN	.0	1.73574	1.73574	1.73574	1.73574	1.73574
TOTAL COST OF ELEC	.0	21.22834	21.72913	22.53375	22.22991	23.73228

ACCOUNT	RATE, PERCENT	ESCALATION RATE, PERCENT 5.00	6.50	8.00	10.00	.00
TOTAL DIRECT COSTS,$	.0	161914732.	161914732.	161914732.	161914732.	161914732.
INDIRECT COST,$	51.0	26031880.	26031880.	26031880.	26031880.	26031880.
PROF & OWNER COSTS,$	8.0	12953178.	12953178.	12953178.	12953178.	12953178.
CONTINGENCY COST,$	8.0	13007517.	13007517.	13007517.	13007517.	13007517.
SUB TOTAL,$	.0	213907306.	213907306.	213907306.	213907306.	213907306.
ESCALATION COST,$	.0	33411148.	44181892.	55312026.	70725548.	0.
INTREST DURING CONST,$	10.0	49157203.	50949782.	52790090.	55319474.	43516326.
TOTAL CAPITALIZATION,$	.0	296475655.	309038980.	322009420.	339952324.	257427634.
COST OF ELEC-CAPITAL	18.0	12.69404	13.23196	13.78731	14.55556	11.02197
COST OF ELEC-FUEL	.0	7.56605	7.56605	7.56605	7.56605	7.56605
COST OF ELEC-OP & MAIN	.0	1.73574	1.73574	1.73574	1.73574	1.73574
TOTAL COST OF ELEC	.0	21.99583	22.53375	23.08910	23.85735	20.32376

ACCOUNT	RATE, PERCENT	INT DURING CONST,PERCENT 6.00	8.00	10.00	12.50	15.00
TOTAL DIRECT COSTS,$	.0	161914732.	161914732.	161914732.	161914732.	161914732.
INDIRECT COST,$	51.0	26031880.	26031880.	26031880.	26031880.	26031880.
PROF & OWNER COSTS,$	8.0	12953178.	12953178.	12953178.	12953178.	12953178.
CONTINGENCY COST,$	8.0	13007517.	13007517.	13007517.	13007517.	13007517.
SUB TOTAL,$	.0	213907305.	213907305.	213907306.	213907306.	213907306.
ESCALATION COST,$	6.5	44181892.	44181892.	44181892.	44181892.	44181892.
INTREST DURING CONST,$	15.0	29766434.	40220823.	50949782.	64754951.	79007420.
TOTAL CAPITALIZATION,$	.0	287855632.	298310024.	309038980.	322844148.	337096616.
COST OF ELEC-CAPITAL	18.0	12.32497	12.77259	13.23196	13.82305	14.43329
COST OF ELEC-FUEL	.0	7.56605	7.56605	7.56605	7.56605	7.56605
COST OF ELEC-OP & MAIN	.0	1.73574	1.73574	1.73574	1.73574	1.73574
TOTAL COST OF ELEC	.0	21.62675	22.07437	22.53375	23.12484	23.73508

Table 12.27 Continued

FLUIDIZED BED BOILER ADVANCED STEAM SYS   COST OF ELECTRICITY,MILLS/KW.HR

PARAMETRIC POINT NO.31

ACCOUNT	RATE, PERCENT	FIXED CHARGE RATE, PCT 10.00	14.40	18.00	21.60	25.00
TOTAL DIRECT COSTS,$	.0	161914732.	161914732.	161914732.	161914732.	161914732.
INDIRECT COST,$	51.0	26031880.	26031880.	26031880.	26031880.	26031880.
PROF & OWNER COSTS,$	8.0	12953178.	12953178.	12953178.	12953178.	12953178.
CONTINGENCY COST,$	9.0	13007517.	13007517.	13007517.	13007517.	13007517.
SUB TOTAL,$	.0	213907306.	213907306.	213907306.	213907306.	213907306.
ESCALATION COST,$	6.5	44181892.	44181892.	44181892.	44181892.	44181892.
INTREST DURING CONST,$	10.0	50949782.	50949782.	50949782.	50949782.	50949782.
TOTAL CAPITALIZATION,$	.0	309038980.	309038980.	309038980.	309038980.	309038980.
COST OF ELEC-CAPITAL	25.0	7.35109	10.58557	13.23196	15.87835	18.37772
COST OF ELEC-FUEL	.0	7.56605	7.56605	7.56605	7.56605	7.56605
COST OF ELEC-OP & MAIN	.0	1.73574	1.73574	1.73574	1.73574	1.73574
TOTAL COST OF ELEC	.0	16.65288	19.88736	22.53375	25.18014	27.67951

ACCOUNT	RATE, PERCENT	FUEL COST, $/10**6 BTU .50	.85	1.50	2.50	1.02
TOTAL DIRECT COSTS,$	.0	161914732.	161914732.	161914732.	161914732.	161914732.
INDIRECT COST,$	51.0	26031880.	26031880.	26031880.	26031880.	26031880.
PROF & OWNER COSTS,$	9.0	12953179.	12953179.	12953179.	12953179.	12953178.
CONTINGENCY COST,$	8.0	13007517.	13007517.	13007517.	13007517.	13007517.
SUB TOTAL,$	.0	213907306.	213907306.	213907306.	213907306.	213907306.
ESCALATION COST,$	6.5	44181892.	44181892.	44181892.	44181892.	44181892.
INTREST DURING CONST,$	10.0	50949782.	50949782.	50949782.	50949782.	50949782.
TOTAL CAPITALIZATION,$	.0	309038980.	309038980.	309038980.	309038980.	309038980.
COST OF ELEC-CAPITAL	19.0	13.23196	13.23195	13.23196	13.23196	13.23196
COST OF ELEC-FUEL	.0	4.45061	7.56605	13.35184	22.25308	9.07925
COST OF ELEC-OP & MAIN	.0	1.73574	1.73574	1.73574	1.73574	1.73574
TOTAL COST OF ELEC	.0	19.41832	22.53375	28.31955	37.22078	24.04696

ACCOUNT	RATE, PERCENT	CAPACITY FACTOR, PERCENT 12.00	45.00	50.00	55.00	80.00
TOTAL DIRECT COSTS,$	.0	161914732.	161914732.	161914732.	161914732.	161914732.
INDIRECT COST,$	51.0	26031880.	26031880.	26031880.	26031880.	26031880.
PROF & OWNER COSTS,$	8.0	12953178.	12953178.	12953178.	12953178.	12953178.
CONTINGENCY COST,$	9.0	13007517.	13007517.	13007517.	13007517.	13007517.
SUB TOTAL,$	.0	213907306.	213907306.	213907306.	213907306.	213907306.
ESCALATION COST,$	6.5	44181892.	44181892.	44181892.	44181892.	44181892.
INTREST DURING CONST,$	10.0	50949782.	50949782.	50949782.	50949782.	50949782.
TOTAL CAPITALIZATION,$	.0	309038980.	309038980.	309038980.	309038980.	309038980.
COST OF ELEC-CAPITAL	18.0	71.67313	19.11283	17.20155	13.23196	10.75097
COST OF ELEC-FUEL	.0	7.56605	7.56605	7.56605	7.56605	7.56605
COST OF ELEC-OP & MAIN	.0	1.73575	1.73574	1.73574	1.73574	1.73574
TOTAL COST OF ELEC	.0	80.97492	28.41462	26.50334	22.53375	20.05276

Table 12.28-FLUIDIZED BED BOILER ADVANCED STEAM SYS

ACCOUNT NO	AUX POWER, MWE	PERC PLANT POW	OPERATION COST	MAINTENANCE COST
4	7.47317	34.62853	45.78594	10.52508
7	2.84334	13.17523	962.21327	.00000
8	.38724	1.79434	.00000	.00000
14	.00000	.00000	10.68122	.00000
18	7.50270	34.76536	.00000	.00000
20	3.37452	15.63654	5.33766	.00000
TOTALS	21.58097	2.92259	1281.52951	10.52508

FLUIDIZED BED BOILER ADVANCED STEAM SYS BASE CASE INPUT

NOMINAL POWER, MWE	759.9000	NET POWER, MWE	738.3190
NOM HEAT RATE, BTU/KW-HR	9649.4374	NET HEAT RATE, BTU/KW-HR	8901.2300
ST TURB HEAT RATE CHANGE	8456.3540		
CONDENSER			
DESIGN PRESSURE, IN HG A	3.5000	NUMBER OF SHELLS	2.0000
NUMBER OF TUBES/SHELL	8715.2932	TUBE LENGTH, FT	71.5510
U, BTU/HR-FT2-F	591.4577	TERMINAL TEMP DIFF, F	5.0000
HEAT REJECTION			
DESIGN TEMP, F	77.0000	APPROACH, F	15.6713
RANGE, F	23.0000	OFF DESIGN TEMP, F	51.4000
OFF DESIGN PRES, IN HG A	2.3941	LP TURBINE BLADE LEN, IN	25.0000

1	759.900	2	.000	3	.000	4	9457.600	5	5.000
6	617.200	7	3.500	8	876400000.000	9	2.000	10	1.000
11	1.000	12	161.200	13	1.000	14	.000	15	.000
16	2.000	17	136.000	18	3.000	19	5.000	20	2.500
21	.000	22	13200.0[illegible]	23	.000	24	1550.000	25	400.000
26	3375000.000	27	10000.000	28	17500.000	29	1000000.000	30	1.100
31	1.250	32	1040.000	33	.000	34	1.200	35	1.200
36	3640000.000	37	675.000	38	1.000	39	1.000	40	322000.000
41	77000.000	42	528000.000	43	12033.000	44	555000.000	45	400000.000
46	.000	47	.000	48	3.000	49	2.000	50	.000
51	.500	52	5.353						
1	1.000	2	26615000.000	3	17744000.000	4	1.000	5	1.000
6	1.000	7	1.333	9	1.000	9	1700000.000	10	.050
11	900000.000	12	.050	13	3400000.000	14	.050	15	8300000.000
16	.150	17	14030000.000	18	.000	19	1.000	20	1.000
21	900000.000	22	.030	23	4000000.000	24	2300000.000	25	1.000
26	1.000	27	900000.000	29	600000.000	29	2000000.000	30	800000.000
31	.000	32	.000	33	.000	34	1.000	35	.000
36	.000	37	.000	39	.000	39	.000	40	.000
41	.000	42	.000	43	1.000	44	1.000	45	.000
46	.000	47	.000	49	.000	49	2.000	50	1.000

Curve 682213-A

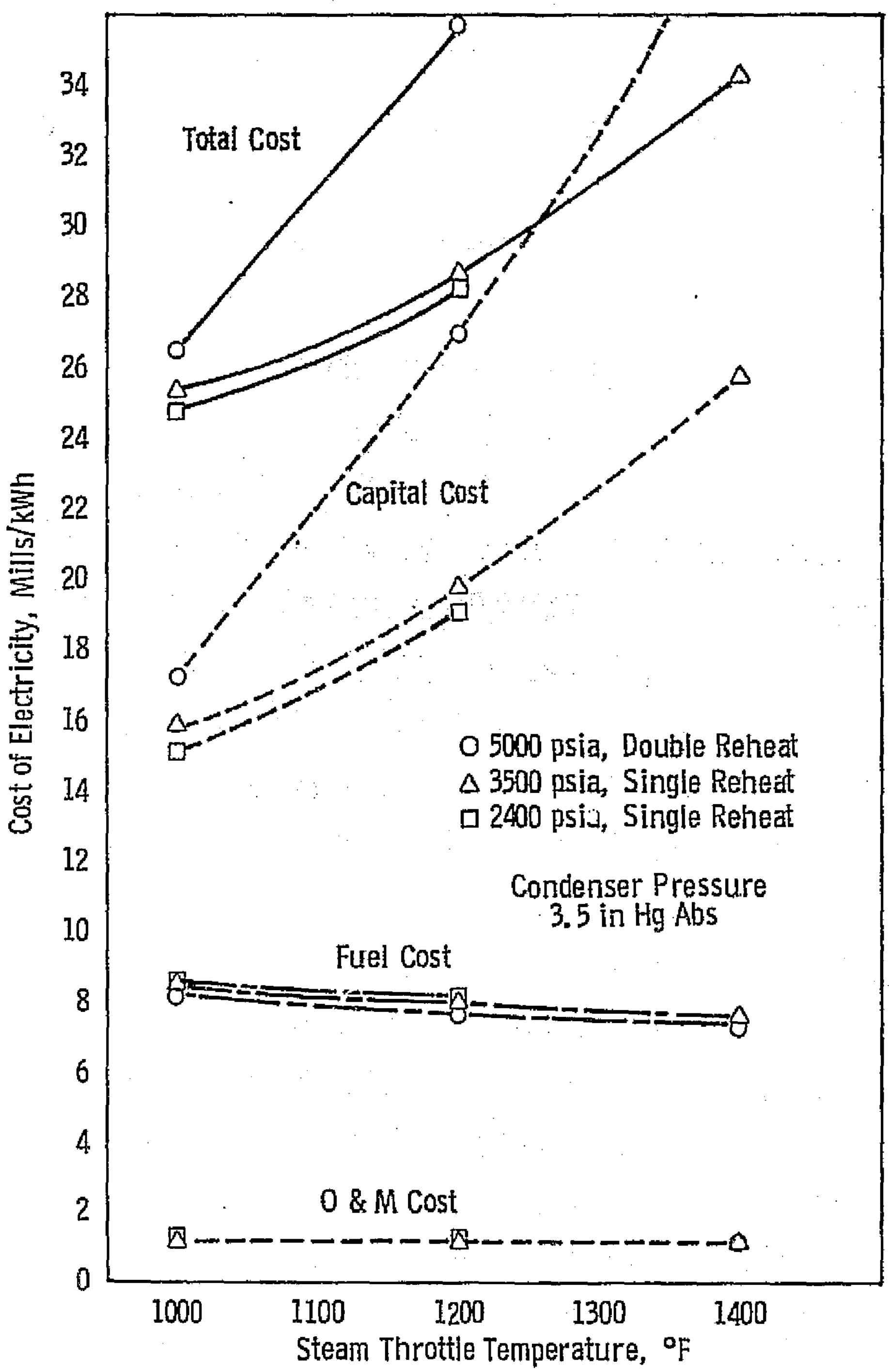

Fig. 12.41—Effect of steam turbine throttle conditions on the cost of electricity from a 500 MWe steam plant with an atmospheric furnace

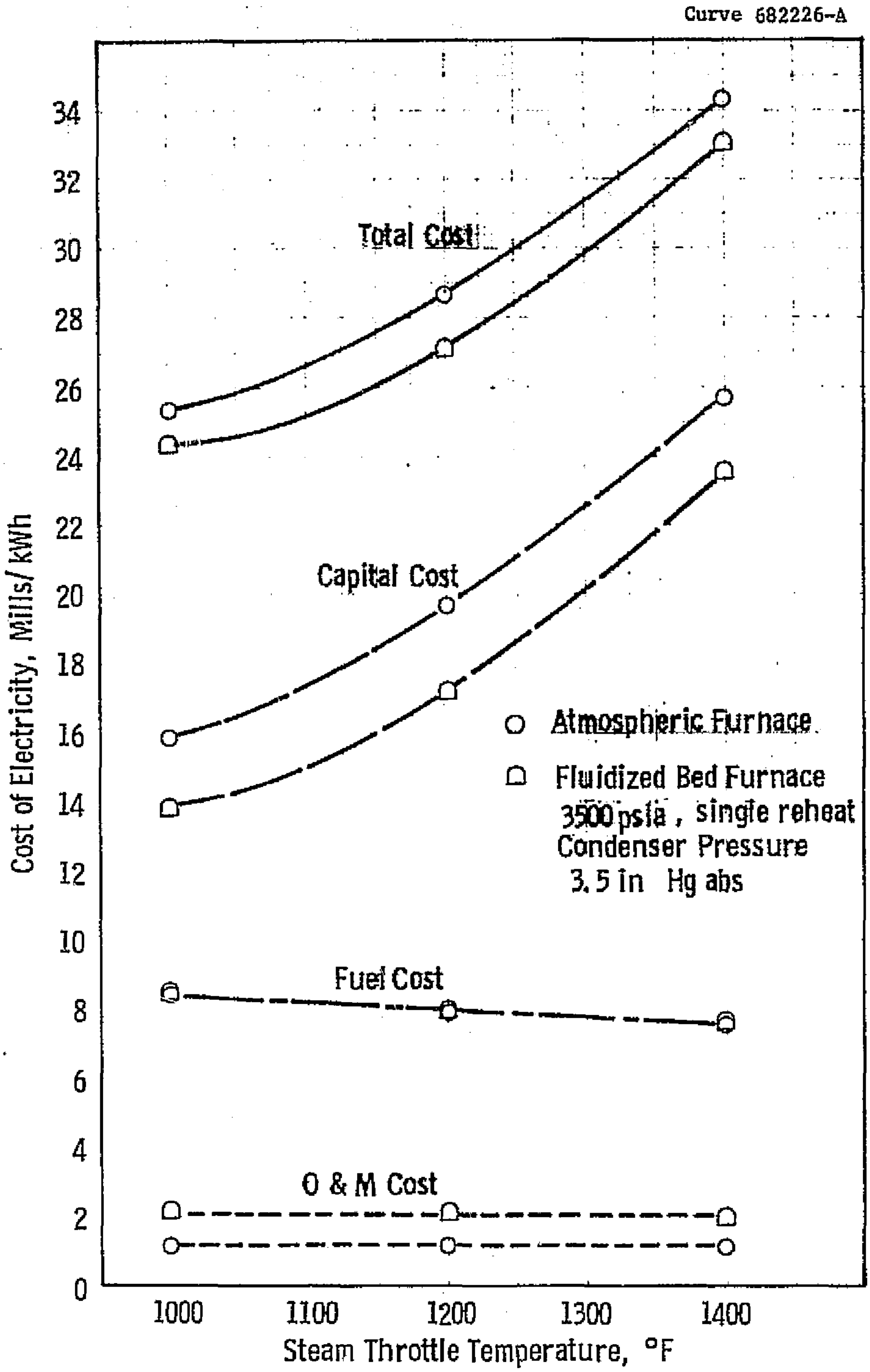

Fig. 12.42 —Effect of steam turbine throttle temperature and furnace type on the cost of electricity from a 500 MWe steam plant

Curve 682221-A

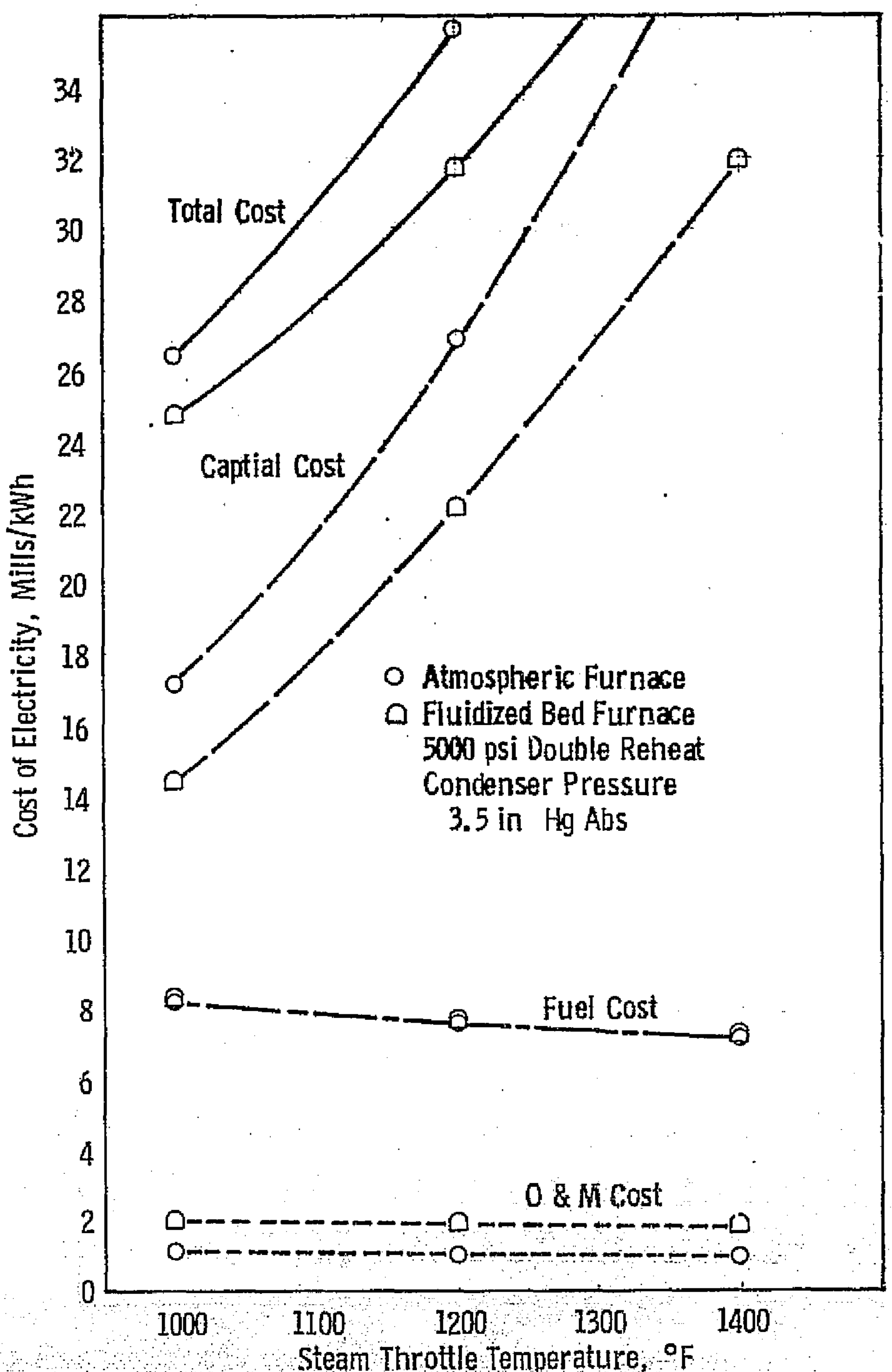

Fig. 12.43 —Effect of steam turbine throttle temperature and furnace type on the cost of electricity for a 500 MWe steam plant

34.472 and 24.132 MPa (5000 and 3500 psi) pressure levels. The fluidized bed plant has a lower capital cost, as would be expected, but the total cost of electricity is essentially the same as the 811°K (1000°F) level. This is because of a higher operating and maintenance cost for the fluidized bed plant, which is due to the greater dolomite usage required when the sulfur cleanup is done at high temperature in the fluidized bed, as compared to the lower temperature of a stack-gas scrubber.

Figure 12.44 shows the effect of condenser pressure on energy cost. The contribution of fuel cost increases nearly linearly with increasing pressure, as might be expected. The capital cost, on the other hand, depends upon the condenser temperature (defined by the condenser pressure), the ambient temperature, and the assumed cooling method. As described in Section 2 of this report, two ambient conditions were used in the study: ISO and 5% day. For the results shown on Figure 12.44, wet cooling towers were used with the ISO and 5% day ambients producing 6.754 kPa (2 in Hg) abs and 11.819 kPa (3.5 in Hg) abs condenser back pressure,respectively. The 30.392 kPa (9 in Hg) abs condenser back pressure was produced by the use of dry cooling towers working in a 5% day ambient.

As can be seen from Figure 12.44, the capital cost decreases as the back pressure decreases from 30.392 kPa (9 in Hg) abs to 11.819 kPa (3.5 in Hg) abs. This is due primarily to the lower cost of wet cooling towers compared to that of dry cooling towers.

If wet cooling towers were used to produce a 6.754 kPa (2 in Hg) abs back pressure for a 5% day their cost would be excessive. Accordingly, the ISO conditions were assumed for this back pressure, and the result was a very small decrease in capital cost. Thus, for the assumed conditions, the cost of electricity decreases with decreasing condenser pressure, but below 11.819 kPa (3.5 in Hg) abs the improvement is small and the cost of electricity may actually increase.

Figure 12.45 shows the effect of plant size on electrical energy cost. From a nominal level of 500 to 900 MWe the total cost decreases

Curve 682222-A

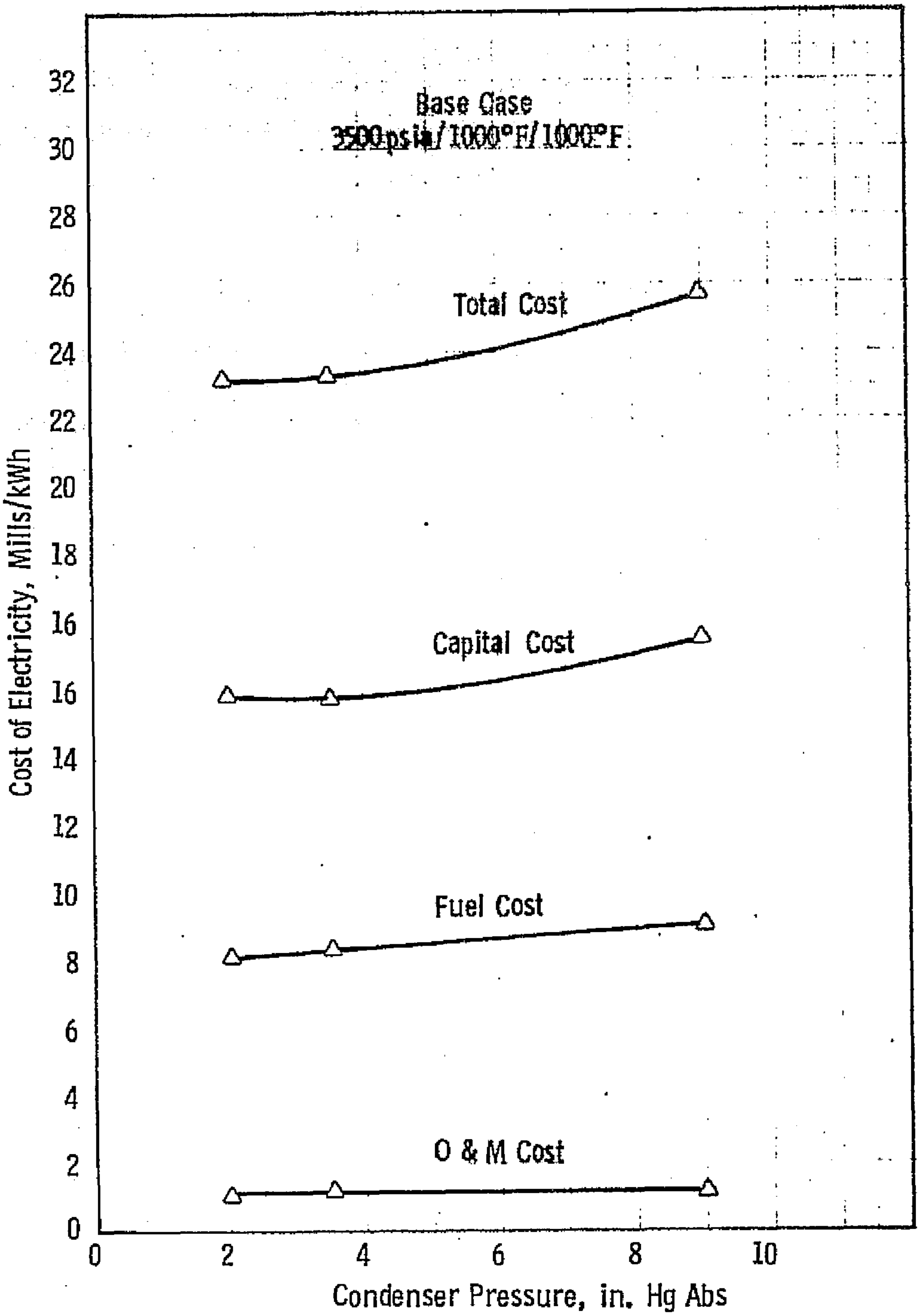

Fig. 12.44—Effect of condenser pressure on the cost of electricity from a 500 MWe steam plant with an atmospheric furnace

Curve 682229-A

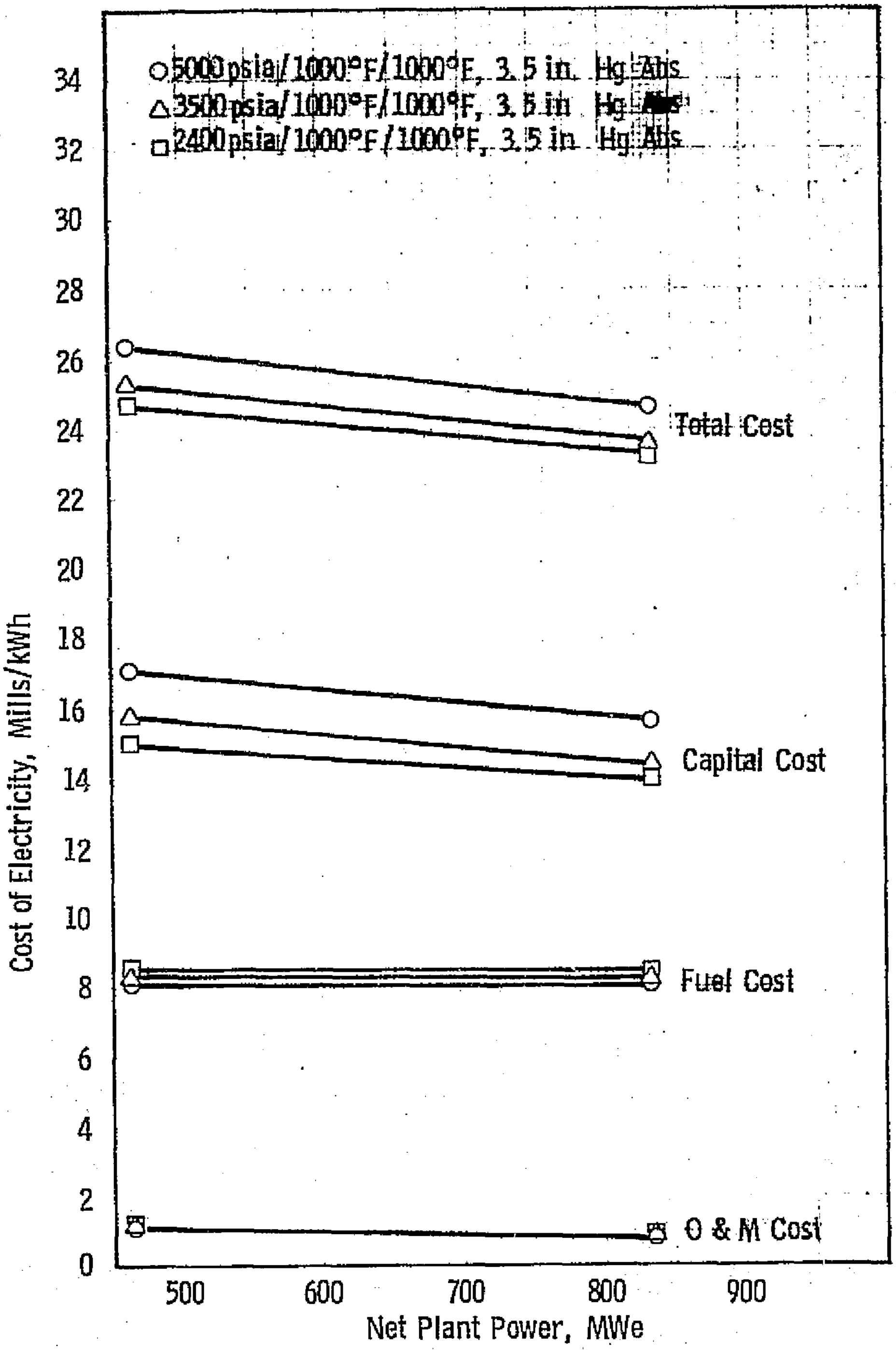

Fig. 12.45 —Effect of plant size and steam turbine throttle condition on the cost of electricity from a steam plant with an atmospheric furnace

Curve 682225-A

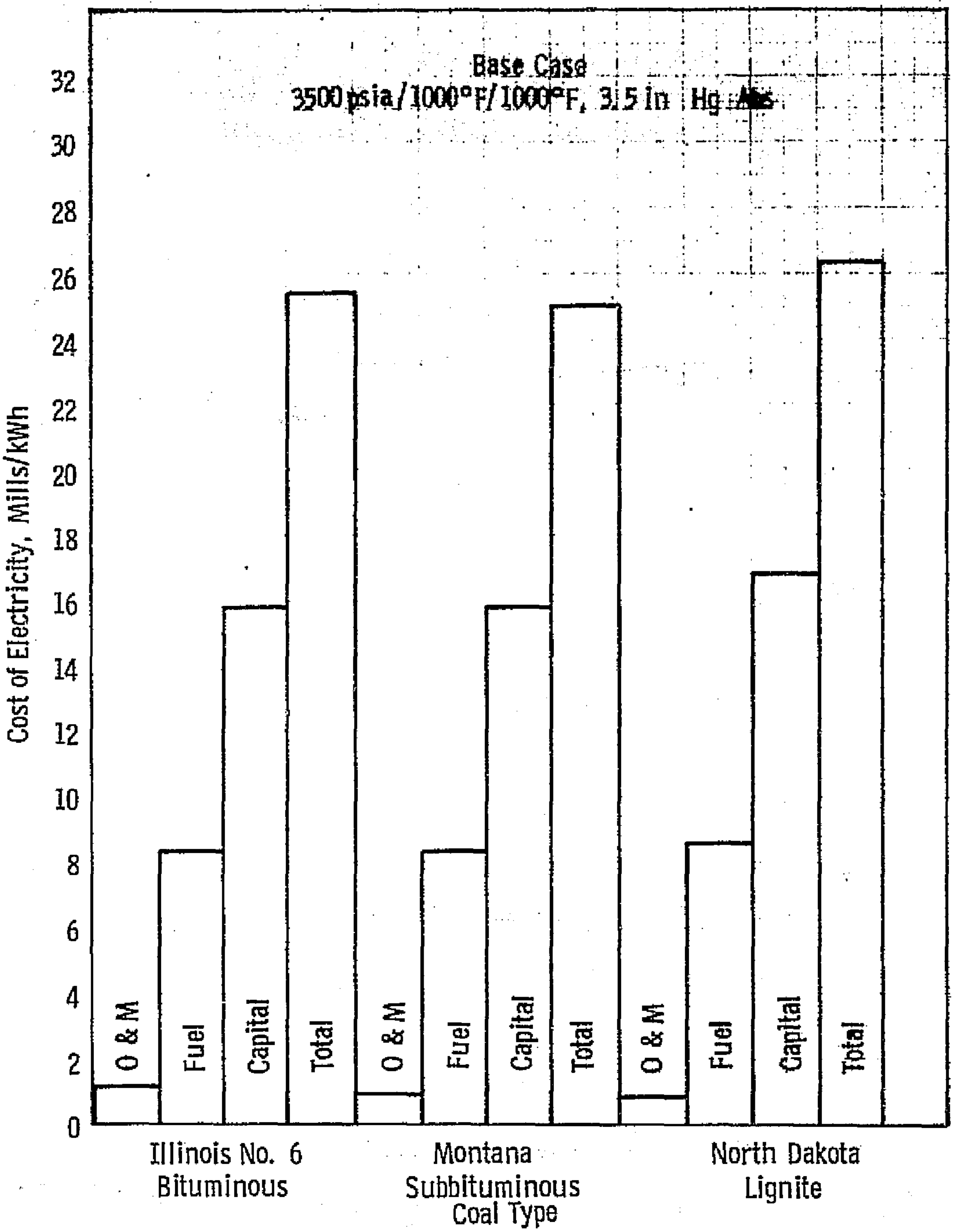

Fig. 12.46—Effect of coal type on the cost of electricity for a 500 MWe steam plant with an atmospheric furnace

approximately 0.278 mill/MJ (1 mill/kWh). Most of this reduction is due tc a reduction in capital cost; the contribution due to fuel cost reduction is negligible.

Figure 12.46 shows the effect of changing coal on energy cost. Montana coal produces slightly lower electrical energy cost than does Illinois No. 6 coal, due primarily to the reduction in dolomite required because of the lower sulfur content. In the case of North Dakota lignite the effect of the smaller amount of sulfur is overwhelmed by the still higher moisture content which lowers the boiler efficiency. In addition, the capital cost for North Dakota lignite is higher, due to the increased costs of handling the very moist coal. Thus, compared to Illinois No. 6 coal, the use of Montana coal reduces the cost of electricity by approximately 0.11 mill/MJ (0.4 mill/kWh), while the use of North Dakota lignite increases the cost by approximately 0.19 mill/MJ (0.7 mill/kWh).

Figure 12.47 shows the effect of various combinations of throttle and reheat steam temperatures as a function of the average temperature. In general it can be said that no significant advantages are to be gained from using throttle and reheat temperatures that are different. At the 1033°K (1400°F) level, however, a reduction in the number of reheats reduces the total cost of electricity (because of a substantial reduction in capital cost), even though the fuel cost is increased due to a lower efficiency (see Figure 12.10).

12.6.2 Pressurized Boiler-Gasifier System

Figures 12.48 to 12.50 show the cost of electricity of the pressurized boiler-gasifier system plant as a function of main steam flow for gas turbine inlet temperatures of 1144°K (1600°F), 1367°K (2000°F), and 1644°K (2500°F), respectively. Also shown are the components of the total cost broken into capital, fuel, and O&M cost, as was done for the atmospheric furnace systems.

For the largest steam flow rate corresponding to near stochiometric fuel/air ratio, these three curves are cross-plotted in Figure 12.51 to show energy cost as a function of gas turbine inlet

Curve 682212-A

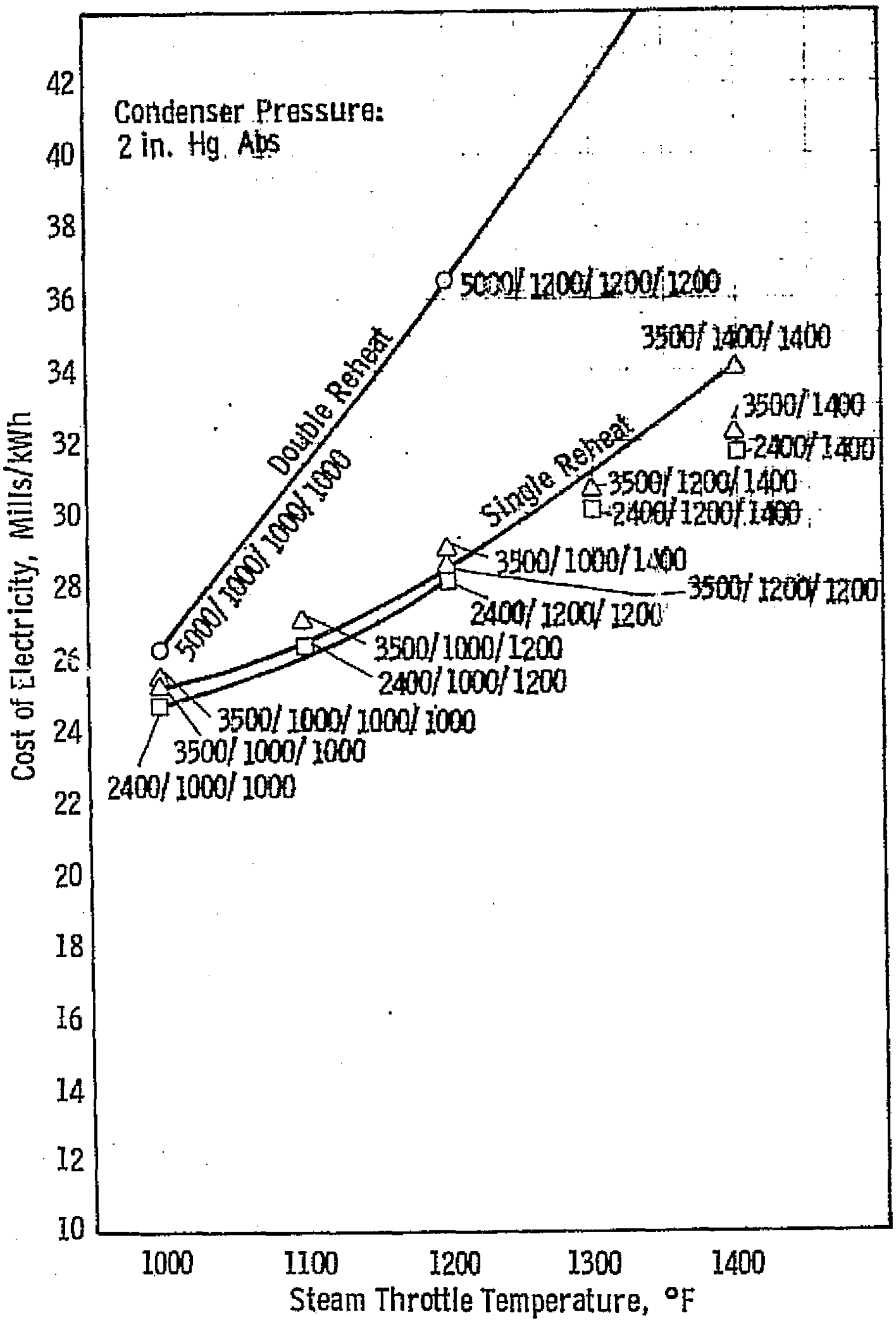

Fig. 12.47—Effect of steam turbine throttle conditions on the cost of electricity for a 500 MWe steam plant with an atmospheric furnace

Curve 682205-A

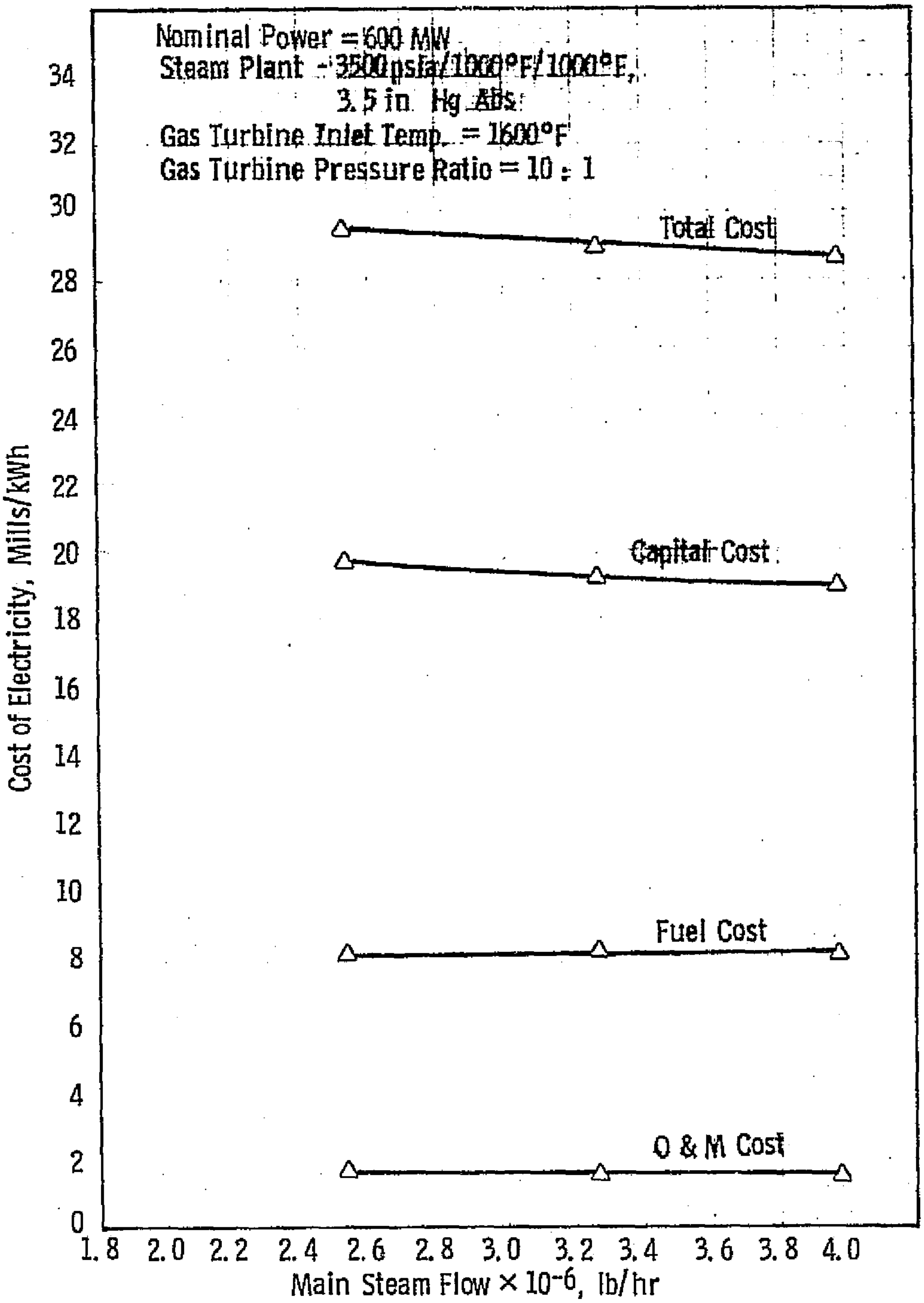

Fig. 12.48 —Effect of steam flow rate on the cost of electricity from a nominal 600 MWe steam plant with pressurized boiler-gasifier system

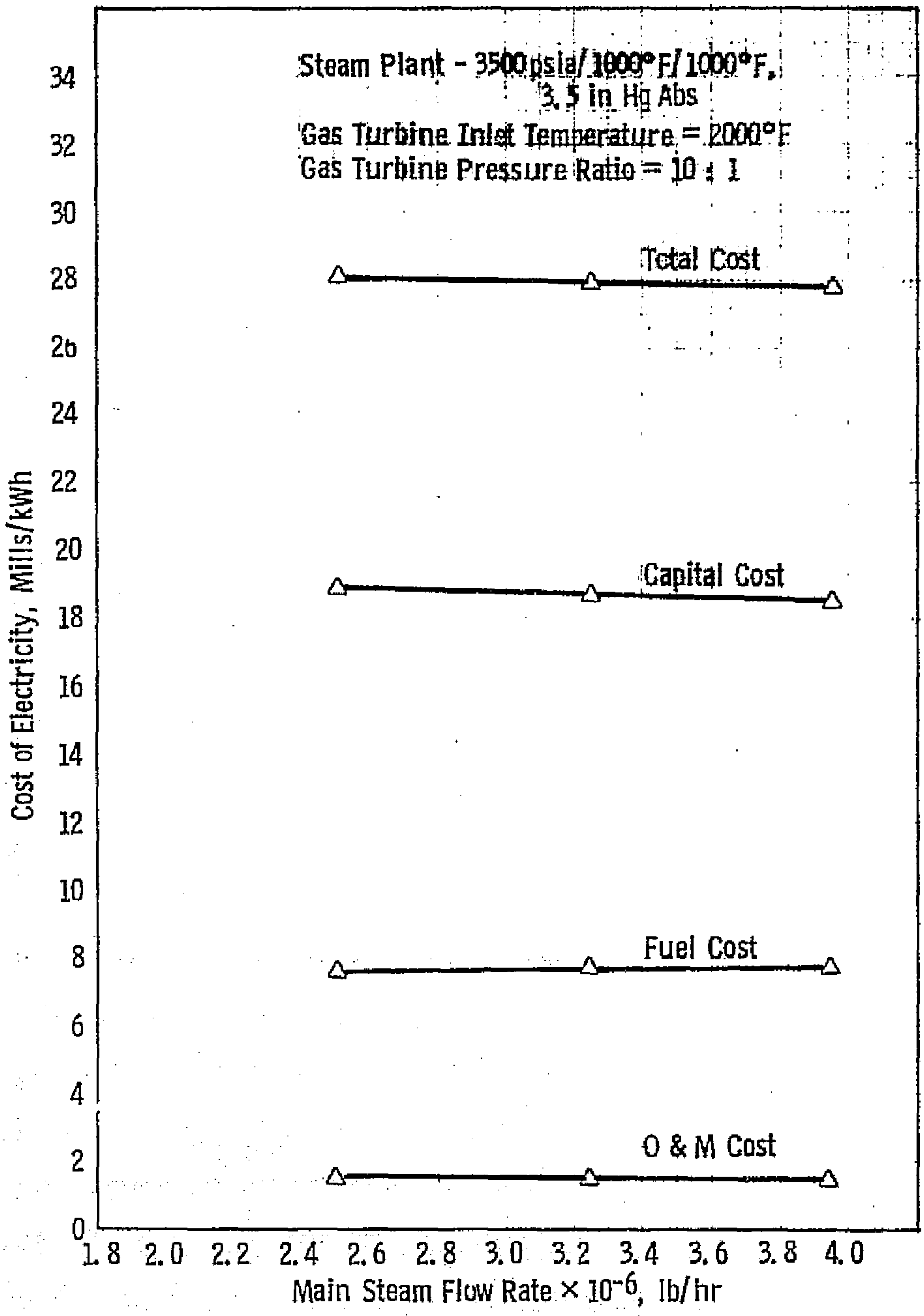

Fig. 12.49—Effect of steam flow rate on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

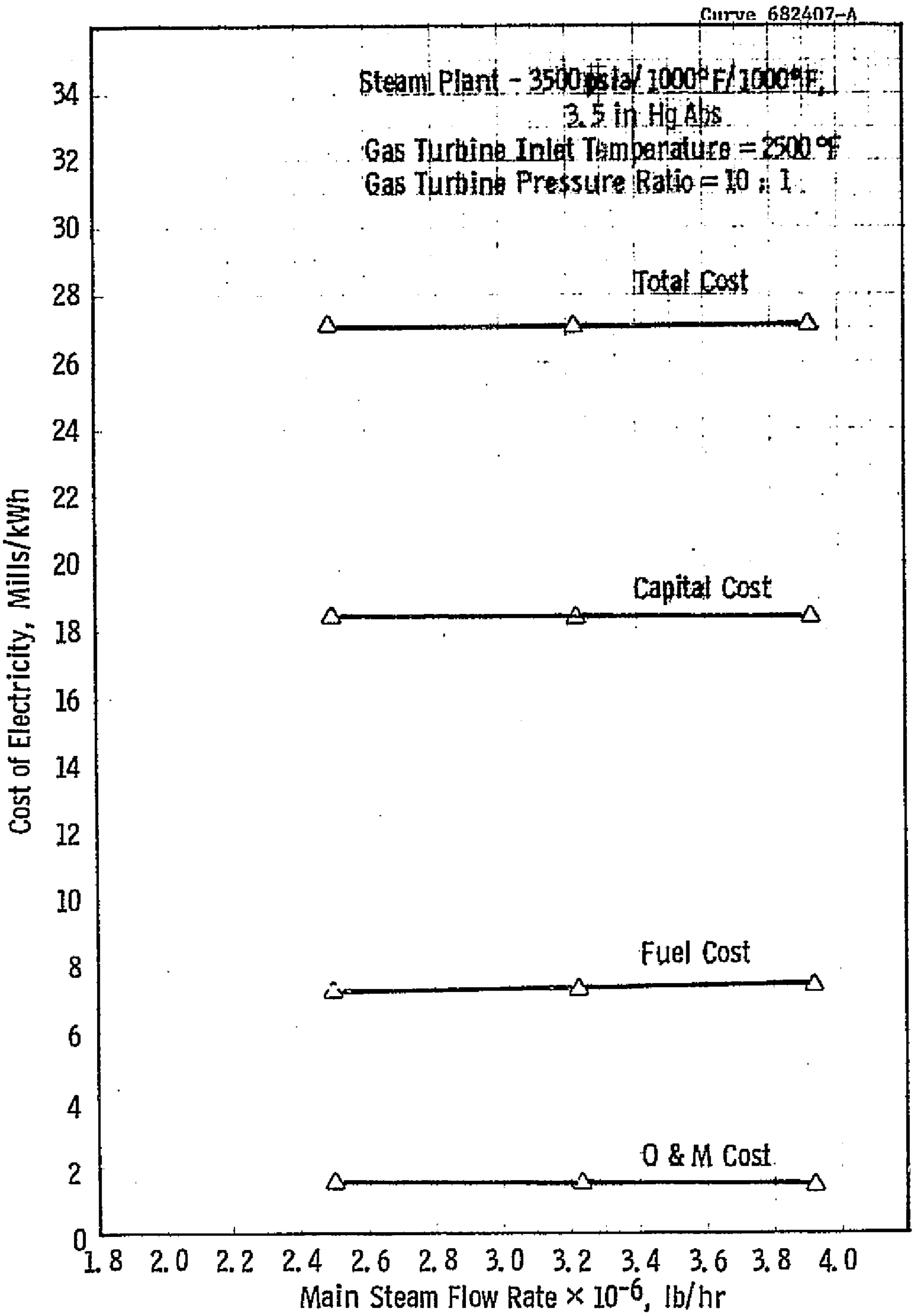

Fig. 12.50—Effect of steam flow rate on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Curve 682207-A

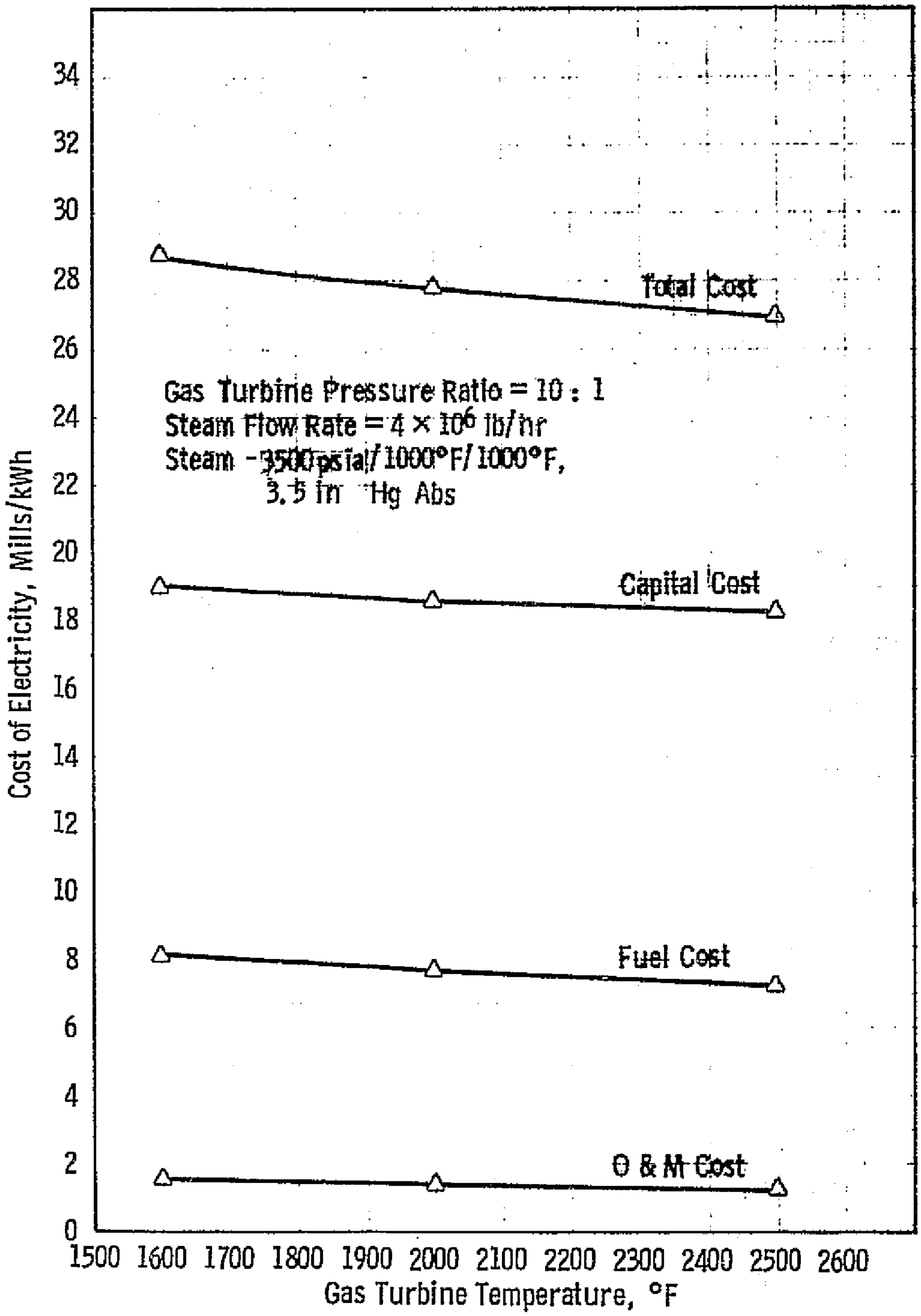

Fig. 12.51—Effect of gas turbine inlet temperature on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

temperature. Both the capital and fuel costs decrease with increasing gas turbine temperature so that the lowest cost of electricity [approximately 7.5 mills/MJ (27 mills/kWh)] occurs at 1644°K (2500°F). This compares to the lowest energy cost of approximately 6.9 mills/MJ (25 mills/kWh) for the atmospheric furnace systems. The higher cost is due to the higher capital cost, of which a major factor is the cost of the coal gasifier subsystem.

Figure 12.52 shows the effect of condenser pressure on electrical energy cost. As would be expected, because the bulk of the power is produced by the steam plant, the increase in cost with increasing condenser pressure is similar to the result found for the atmospheric furnace system.

Figure 12.53 shows the effect of coal type. For this system the use of Illinois No. 6 bituminous coal, which has the highest sulfur content, results in the highest cost. This is primarily due to the considerably larger quantity of dolomite required for sulfur removal in the high-temperature gasifier than in the atmospheric stack-gas cleanup subsystem used with the atmospheric furnace system.

Figure 12.54 shows the effect of improved steam conditions. Because the steam plant costs dominate the gas turbine plant costs, as the steam conditions improve, the cost of electrical energy rises in a manner similar to that of the atmospheric furnace system.

12.6.3 Pressurized Fluidized Bed Boiler System

Figure 12.55 to 12.57 show the cost of electrical energy and a function of main steam flow rate for gas turbine inlet temperatures of 1144°K (1600°F), 1200°K (1700°F), and 1255°K (1800°F). These three curves are comparable to Figures 12.48 to 12.50 for the pressurized boiler-gasifier system. Figure 12.58 is a companion curve to Figure 12.51 but is plotted only up to a gas turbine temperature of 1255°K (1800°F) since the desulfurization reaction requirements limits this. Even so, at 1255°K (1800°F), the cost of electricity is approximately

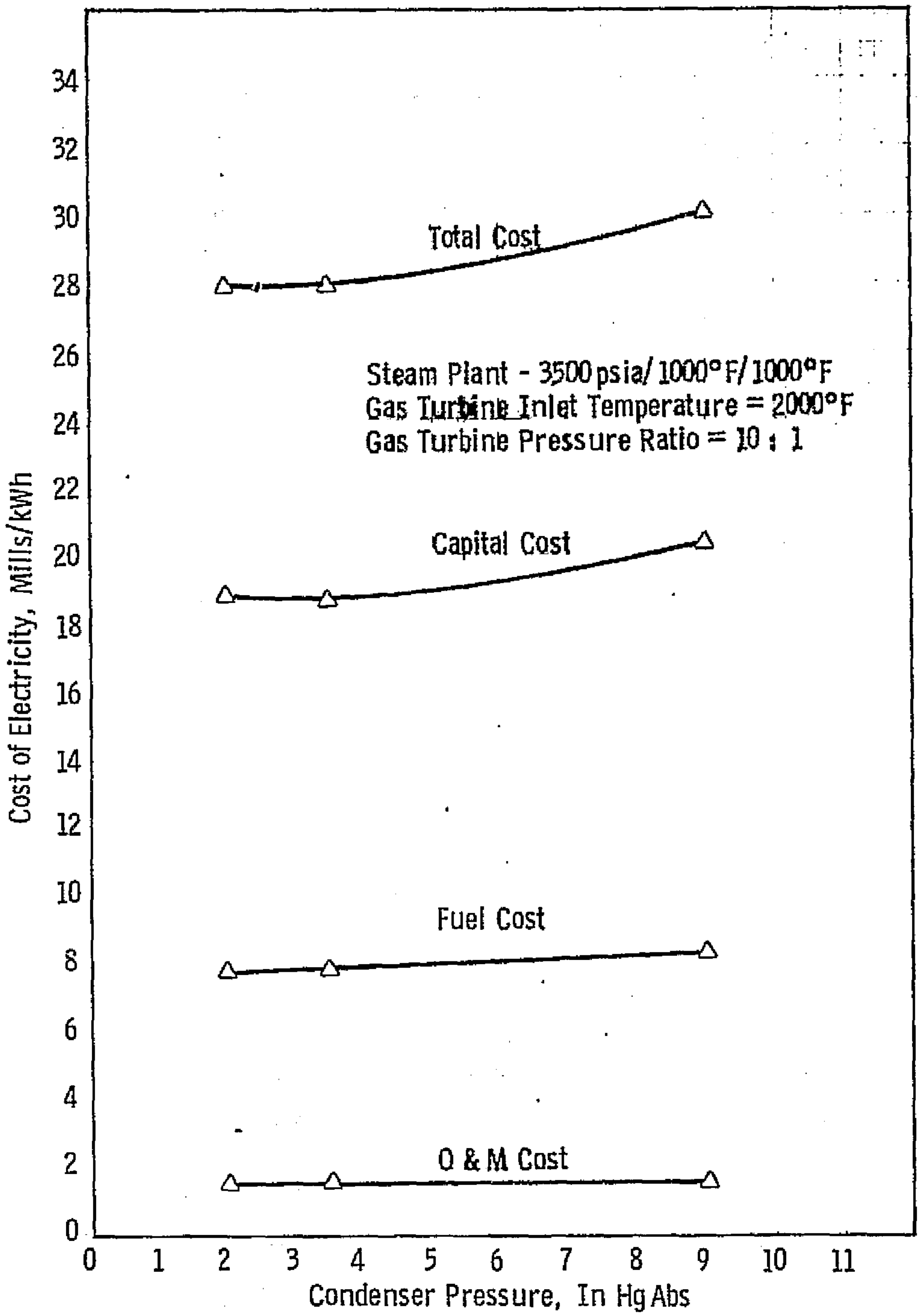

Fig. 12.52—Effect of condenser pressure on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

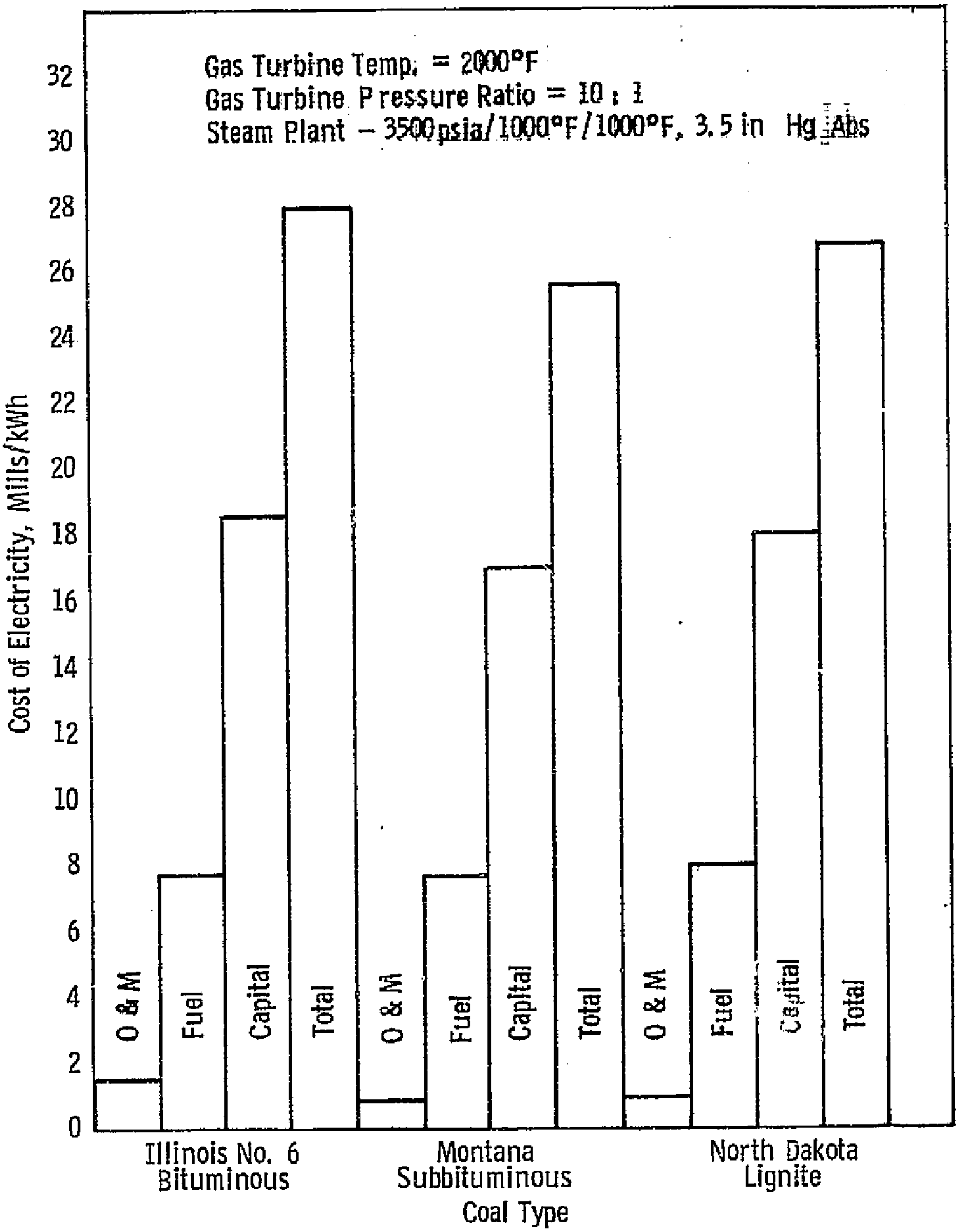

Fig. 12.53—Effect of coal type on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler gasifier system

Curve 682411-A

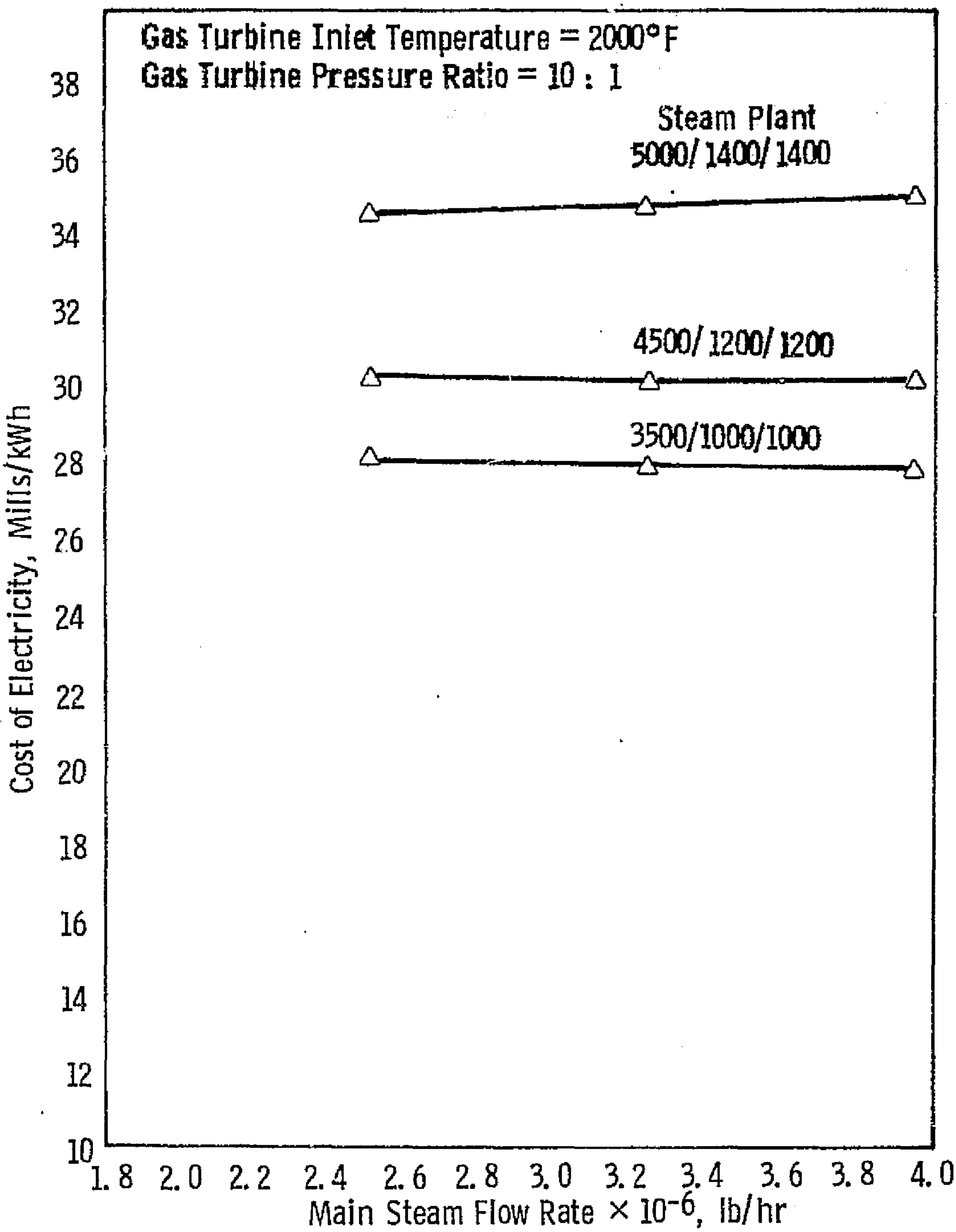

Fig. 12.54—Effect of steam flow rate and throttle conditions on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Curve 682408-A

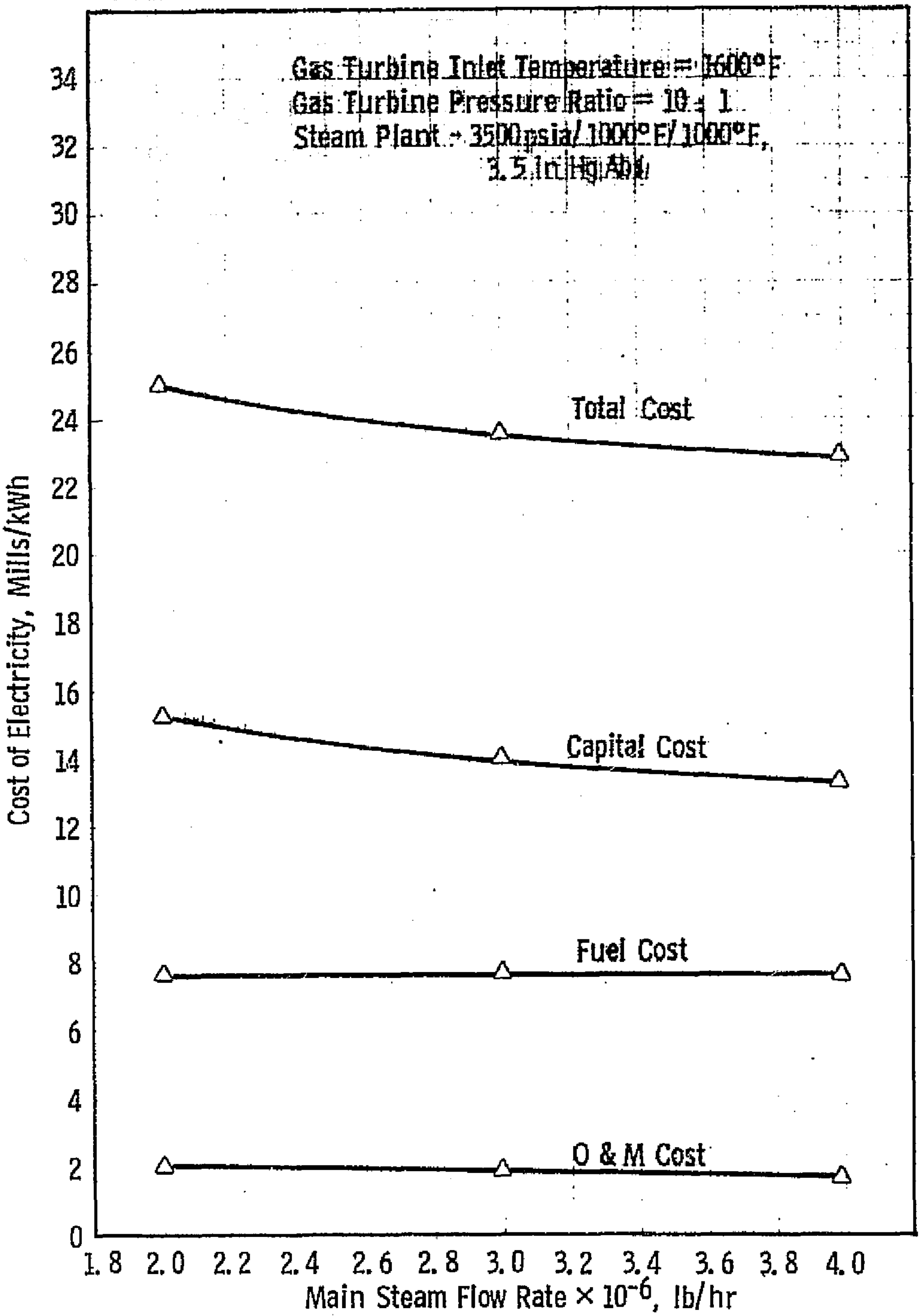

Fig. 12.55—Effect of steam flow rate on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682409-A

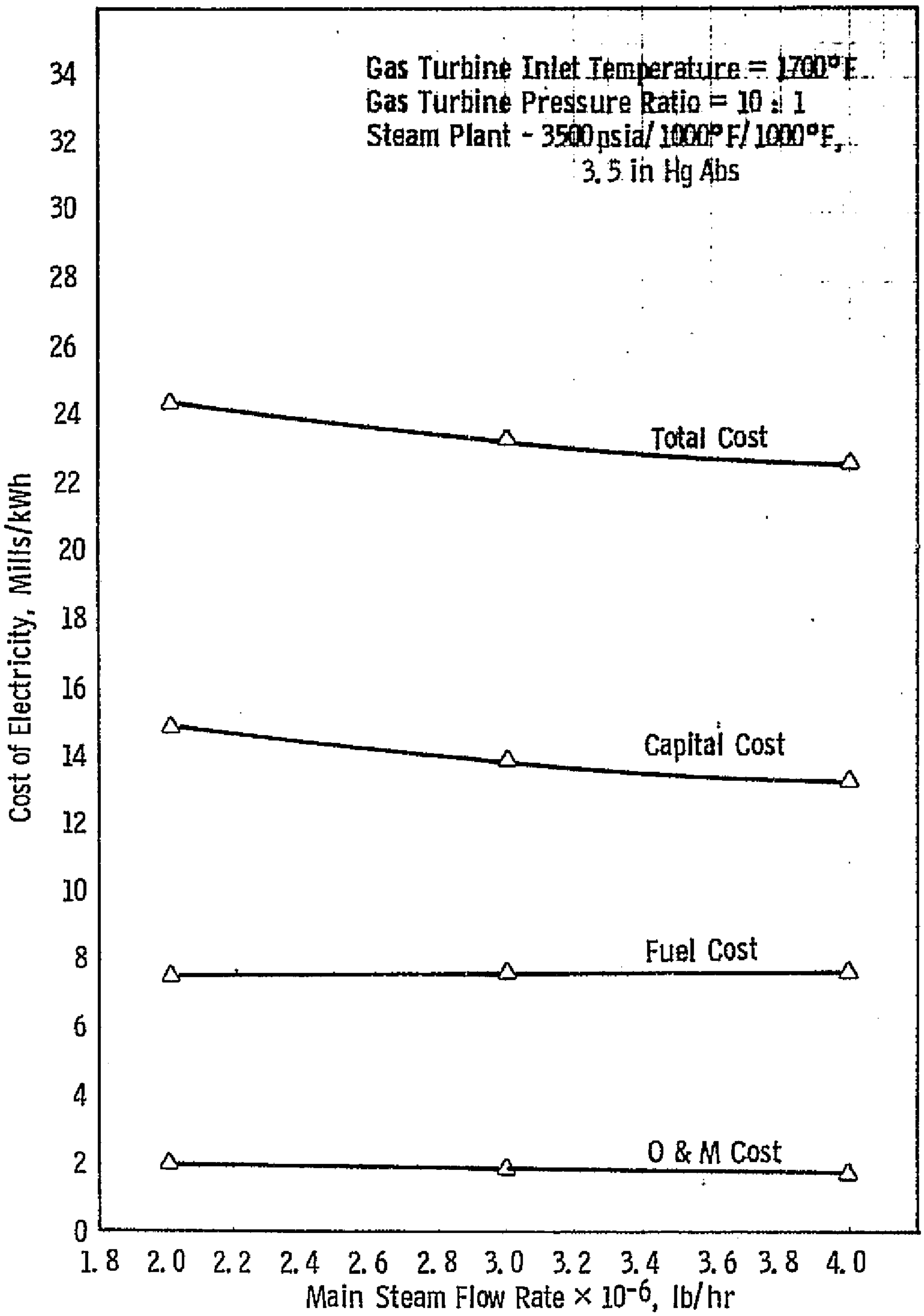

Fig. 12.56—Effect of steam flow rate on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682410-A

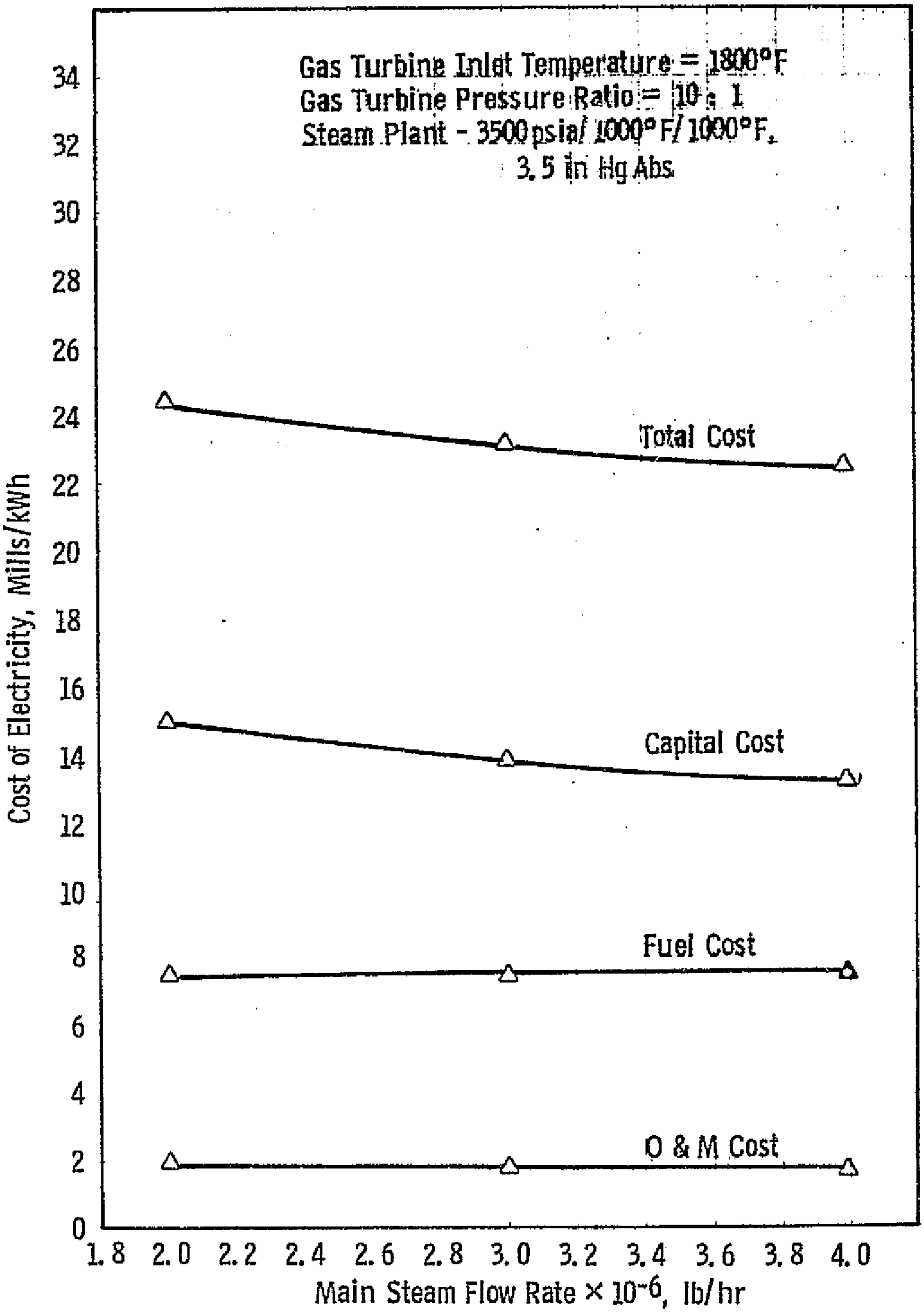

Fig. 12.57—Effect of steam flow rate on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682403-A

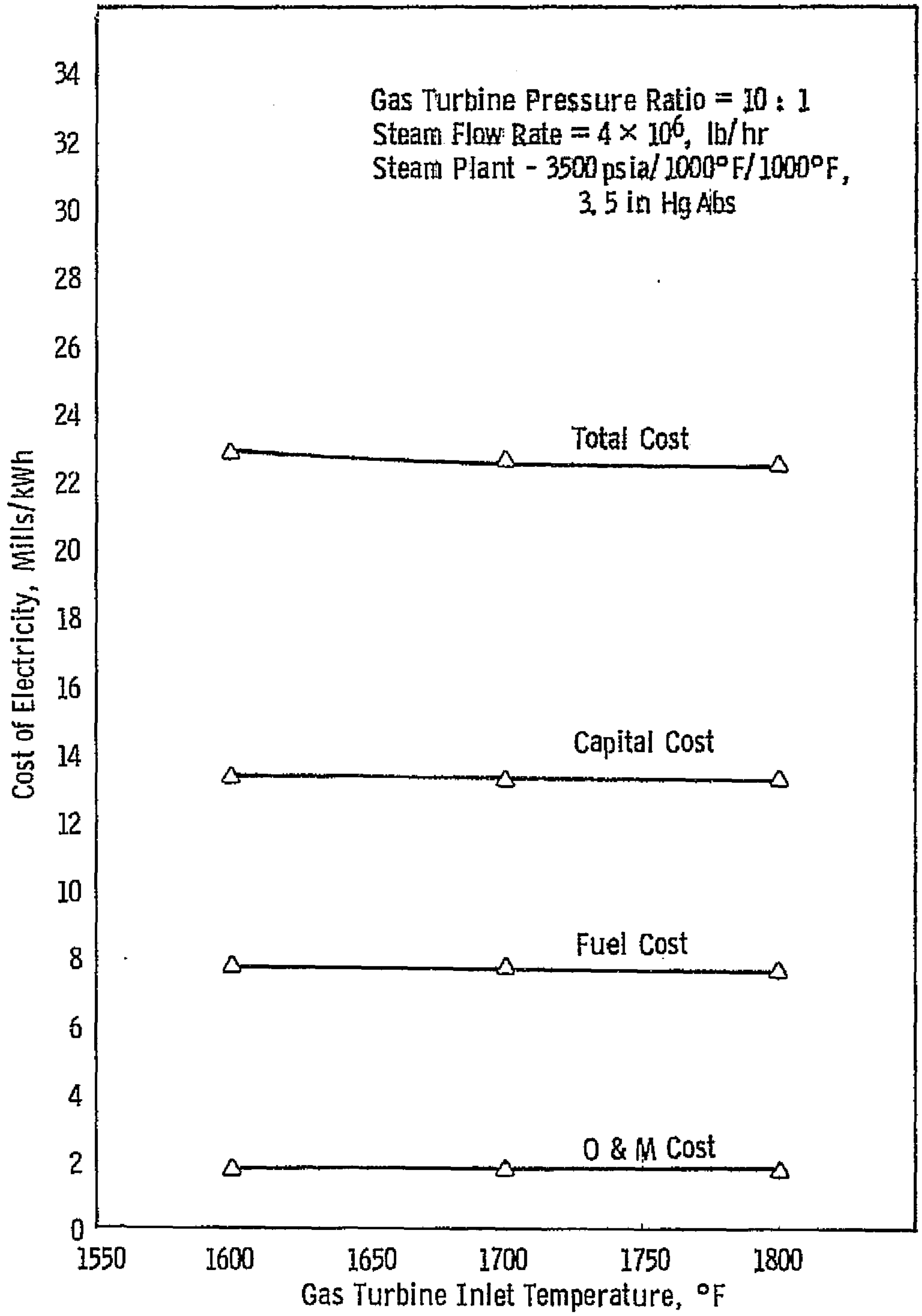

Fig. 12.58—Effect of gas turbine inlet temperature on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

6.3 mills/MJ (22.5 mills/kWh). The cost of electricity for the atmospheric plant is 6.9 mills/MJ (25 mills/kWh); for the atmospheric fluidized bed plant it is 6.6 mills/MJ (24 mills/kWh); and for the pressurized boiler-gasifier plant it is 7.5 mills/MJ (27 mills/kWh). The pressurized fluidized bed boiler system has the lowest energy cost of the three steam systems investigated.

Figure 12.59 shows the same cost trend with condenser back-pressure as was found for the other two systems.

Figure 12.60 again shows the higher cost of electricity associated with Illinois No. 6 coal due to the higher dolomite use required by the high-temperature desulfurization process.

Finally, Figure 12.61 shows the cost of electrical energy increasing with an increasing steam temperature and pressure.

12.6.4 Effect of Other Changes on the Cost of Electricity

Standard values of cost factors such as labor rate, contingency, escalation rate, interest during construction, fixed charges, fuel cost, and capacity factor have been used to calculate the above electrical energy costs. Variations in these cost factors were also investigated for each of the parametric points. For each of the base cases, the relationship between each of these factors and electrical energy cost given in Tables 12.18, 12.22, and 12.26, is displayed graphically in Figures 12.62 through 12.70.

A summary of the economic results for each parametric point was calculated and printed by the computer. These results are shown in Tables 12.29 through 12.31. The major components summations in Table 12.29 include material prices from the following subaccounts:

	Subaccount
• Steam turbine-generator and feed string	11.1, 13.1
• Steam boiler	10.1
• Steam piping	11.3

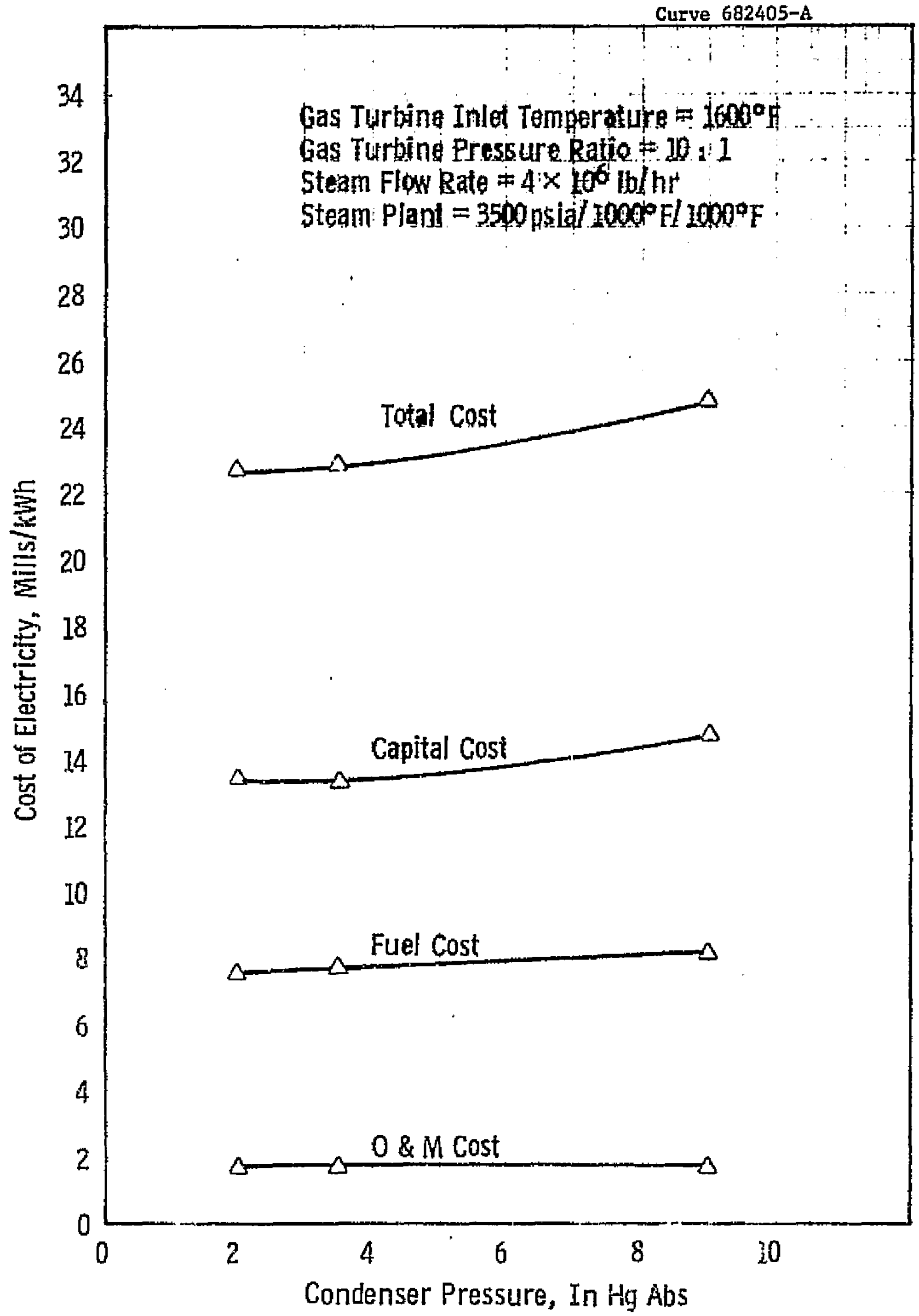

Fig. 12.59—Effect of condenser pressure on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682227-A

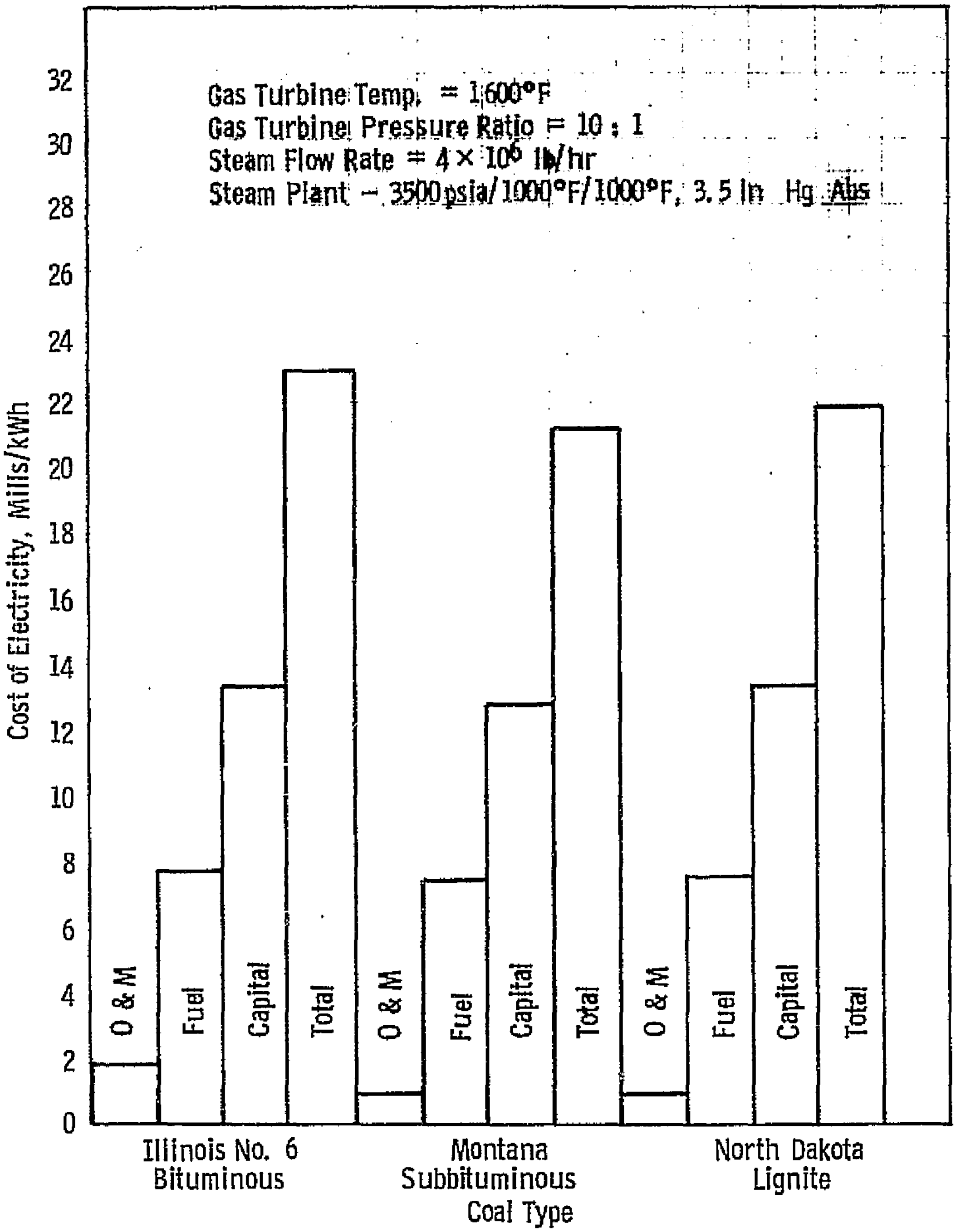

Fig. 12.60 —Effect of coal type on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

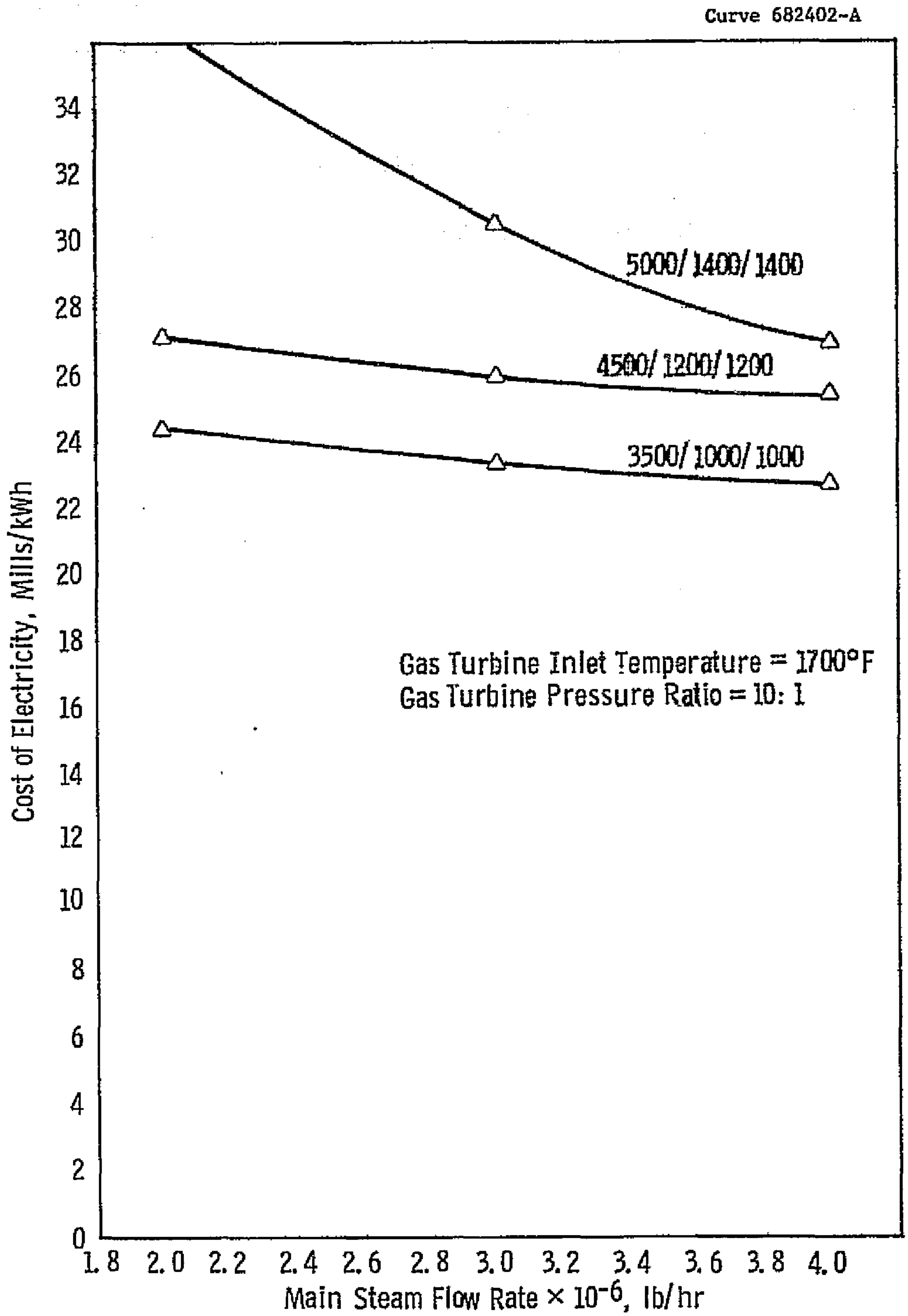

Fig. 12.61 —Effect of steam flow rate and throttle conditions on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

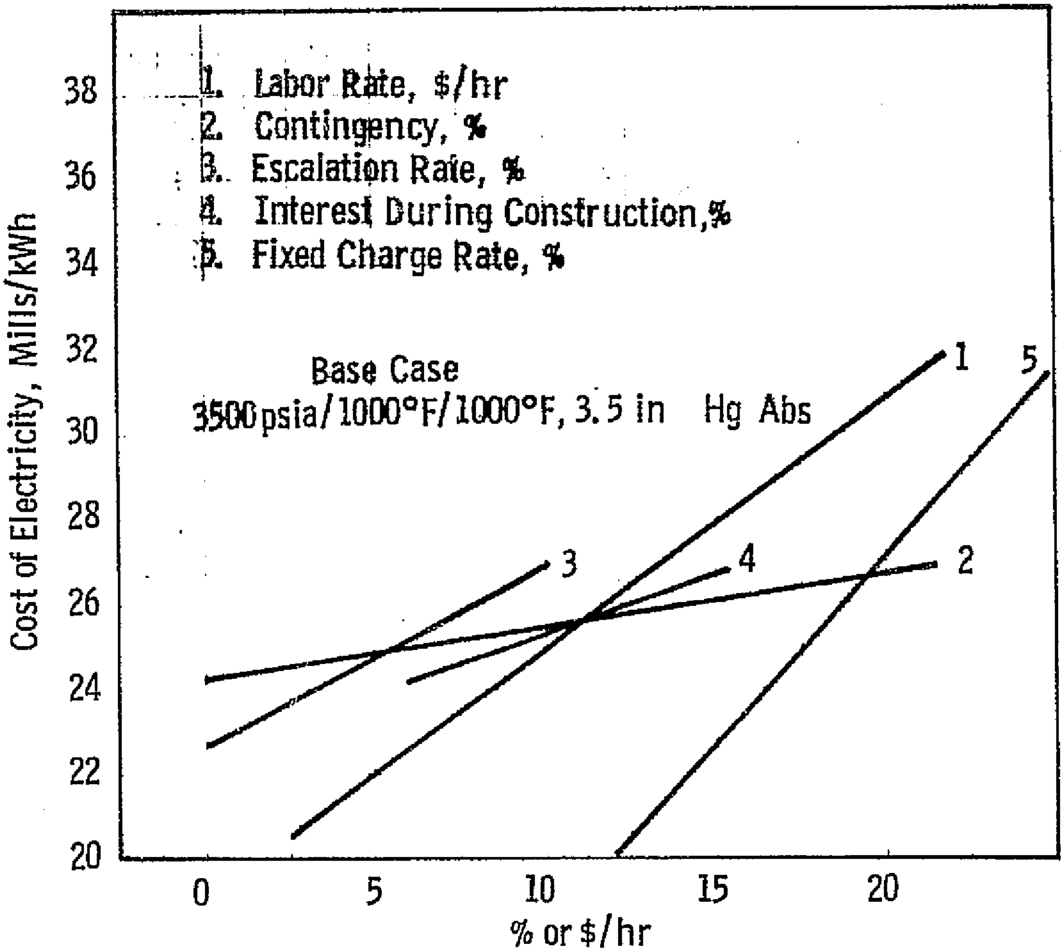

Fig. 12.62—Effect of labor, indirect and fixed costs on the cost of electricity from a 500 MWe steam plant with an atmospheric furnace

Curve 682211-A

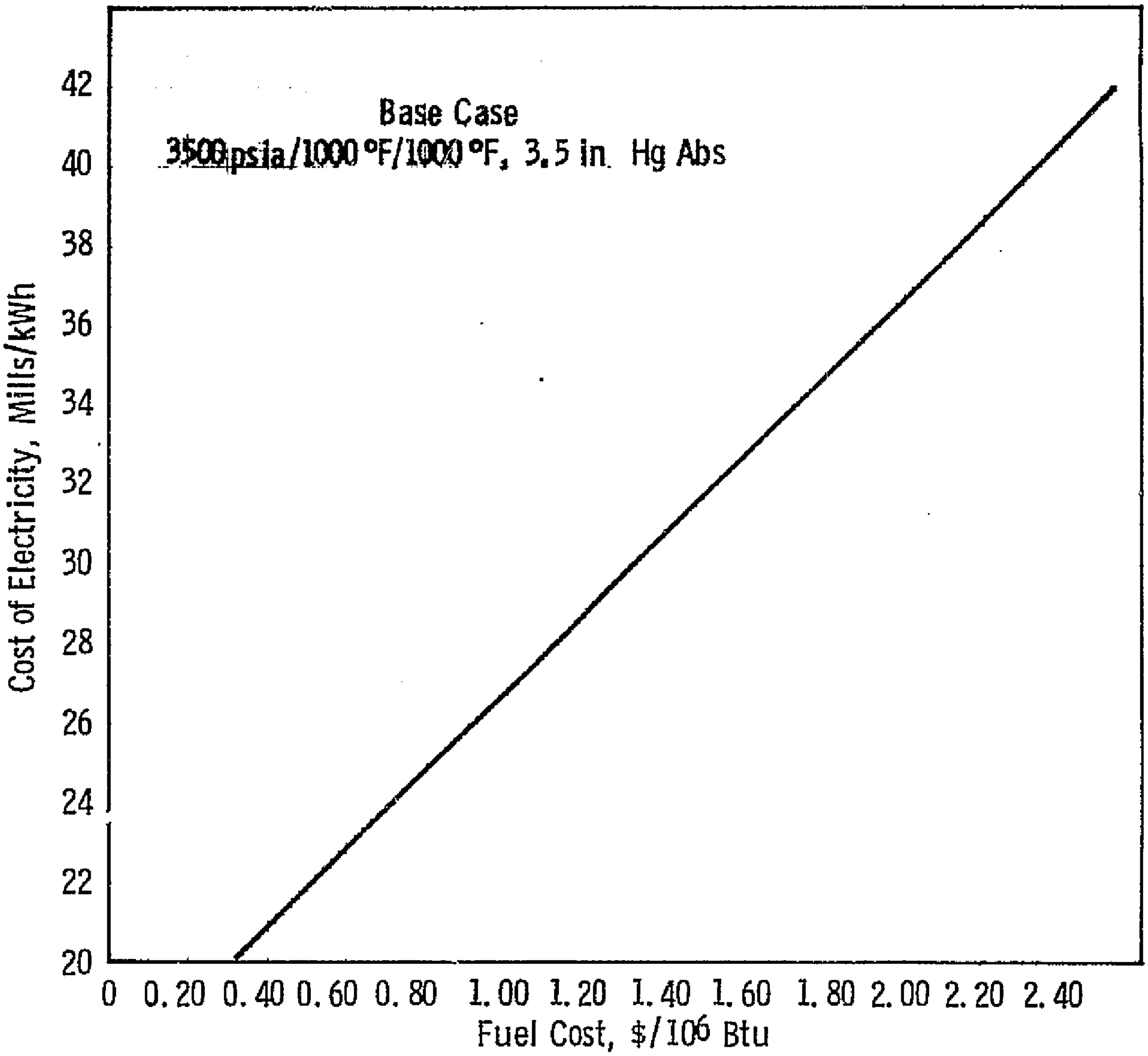

Fig. 12.63—Effect of fuel cost on the cost of electricity from a 500 MWe steam plant with an atmospheric furnace

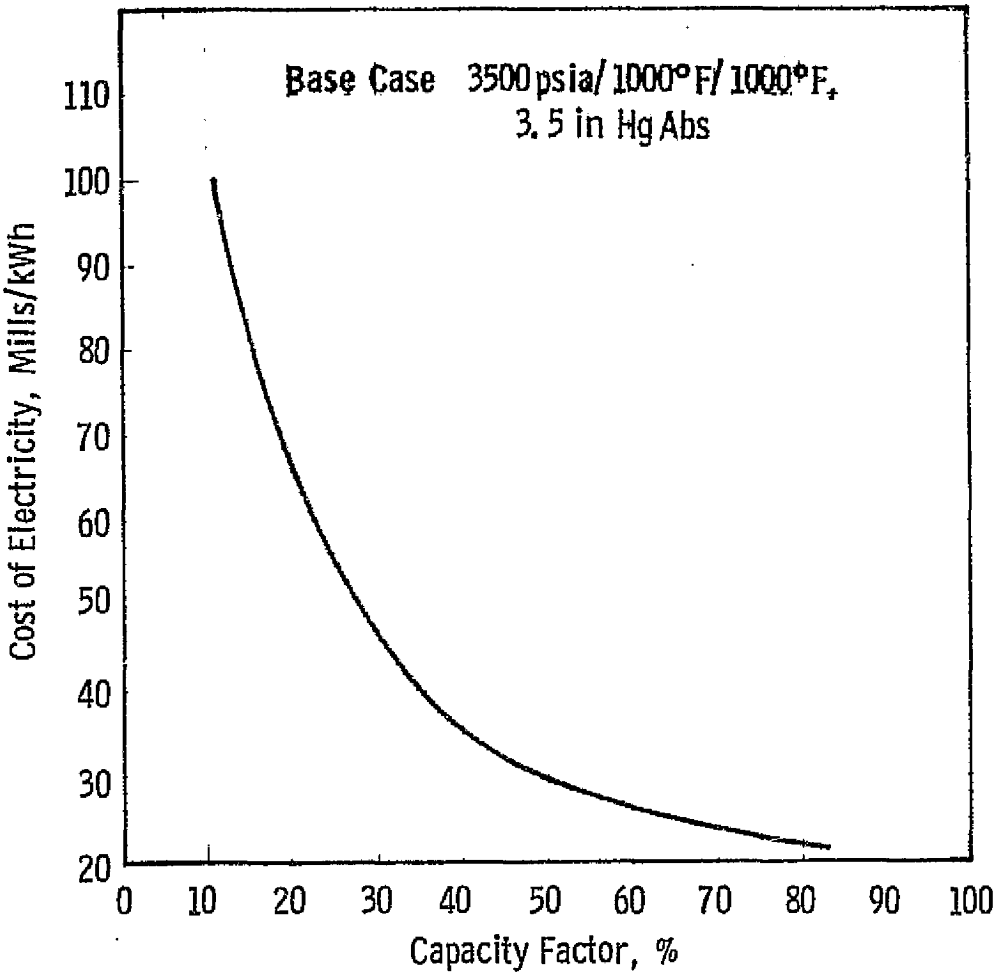

Fig. 12.64—Effect of capacity factor on the cost of electricity from a 500 MWe steam plant with an atmospheric furnace

c

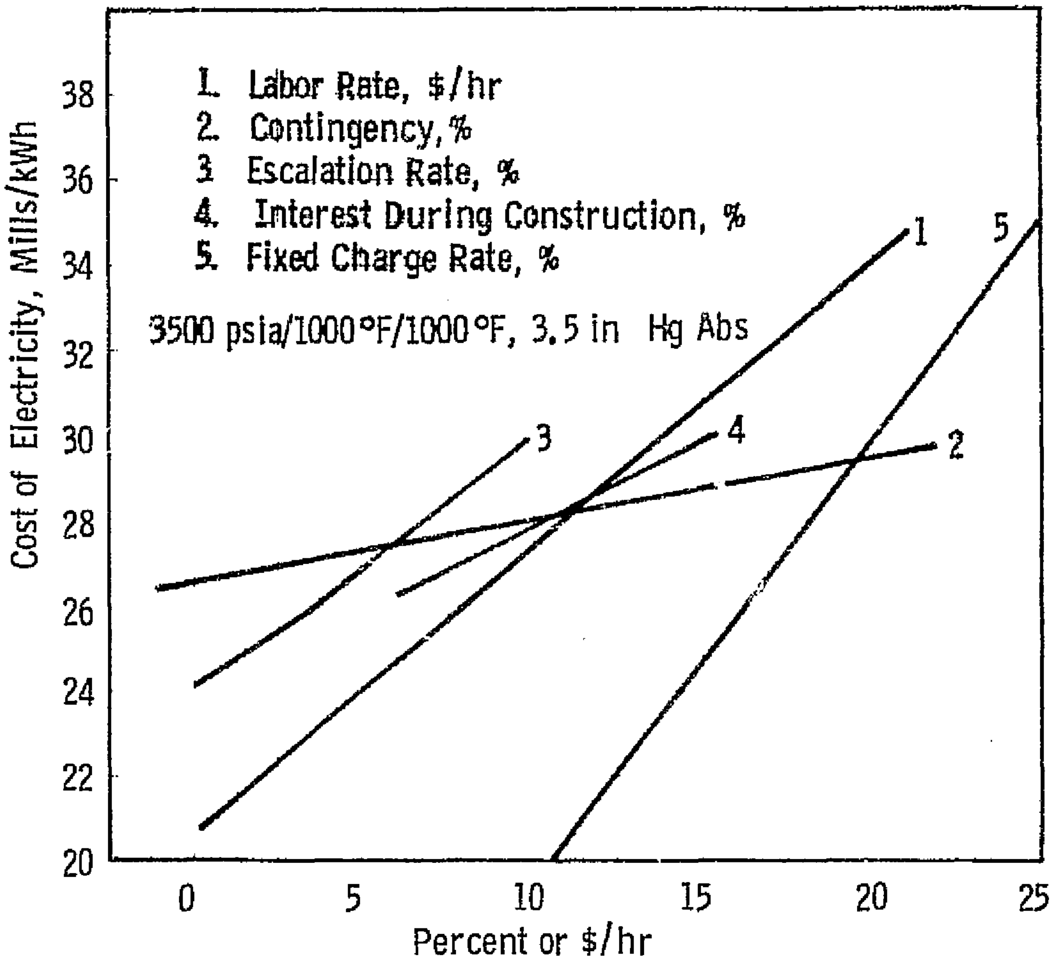

Fig. 12.65—Effect of labor, indirect and fixed costs on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Curve 682413-A

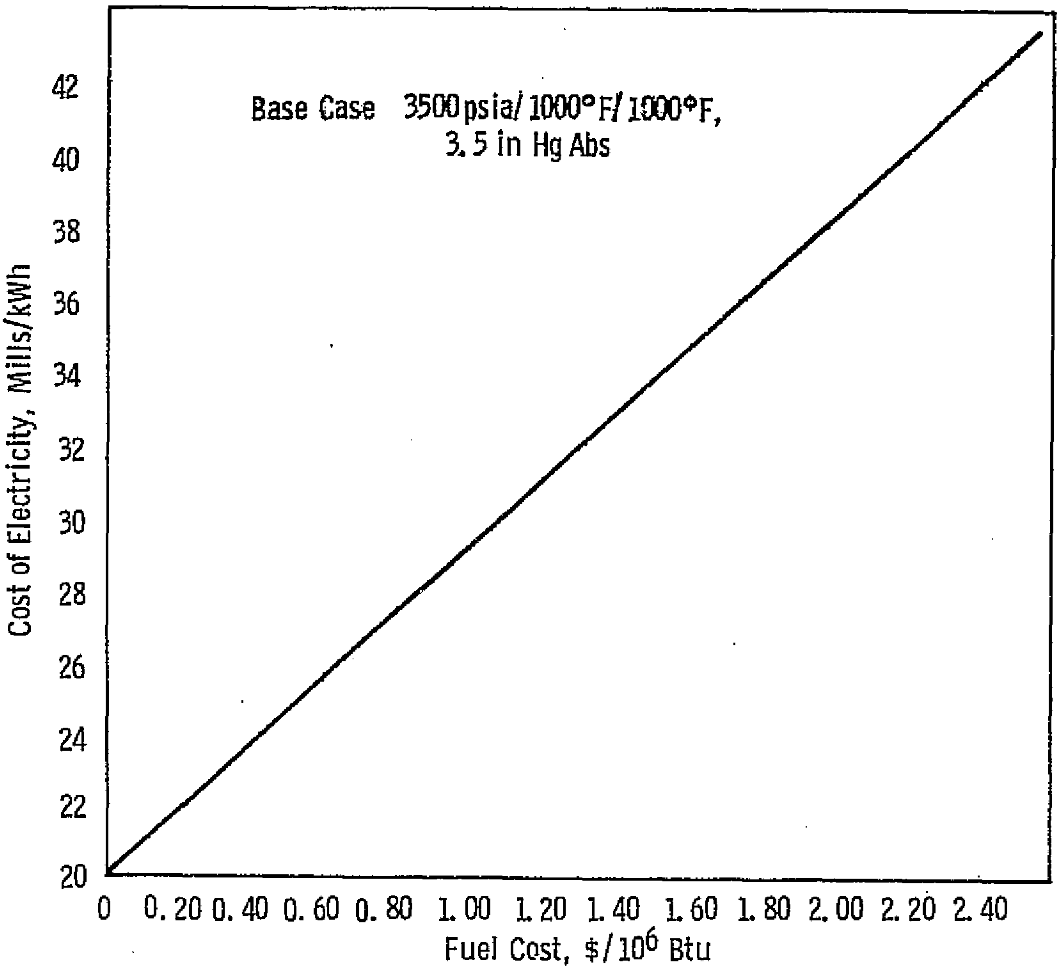

Fig. 12.66—Effect of fuel cost on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Curve 682415-A

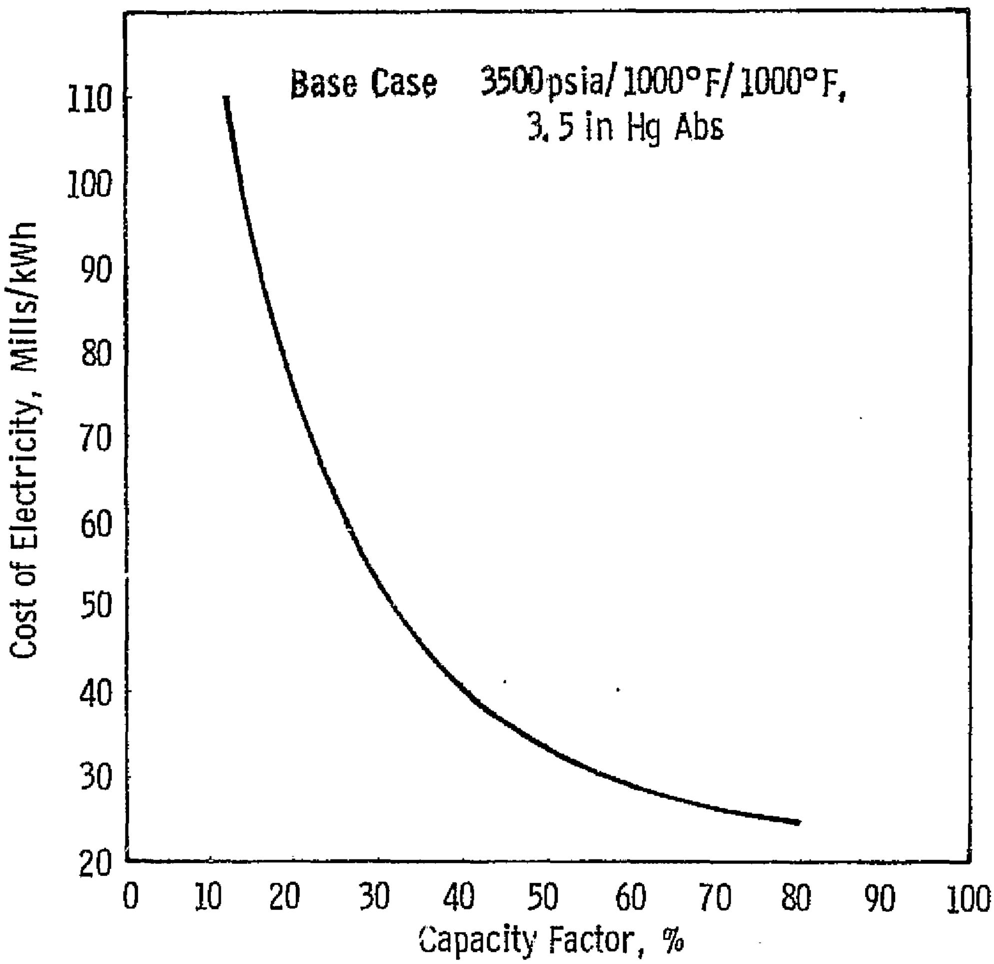

Fig. 12.67—Effect of capacity factor on the cost of electricity from a nominal 600 MWe steam plant with a pressurized boiler-gasifier system

Curve 682412-A

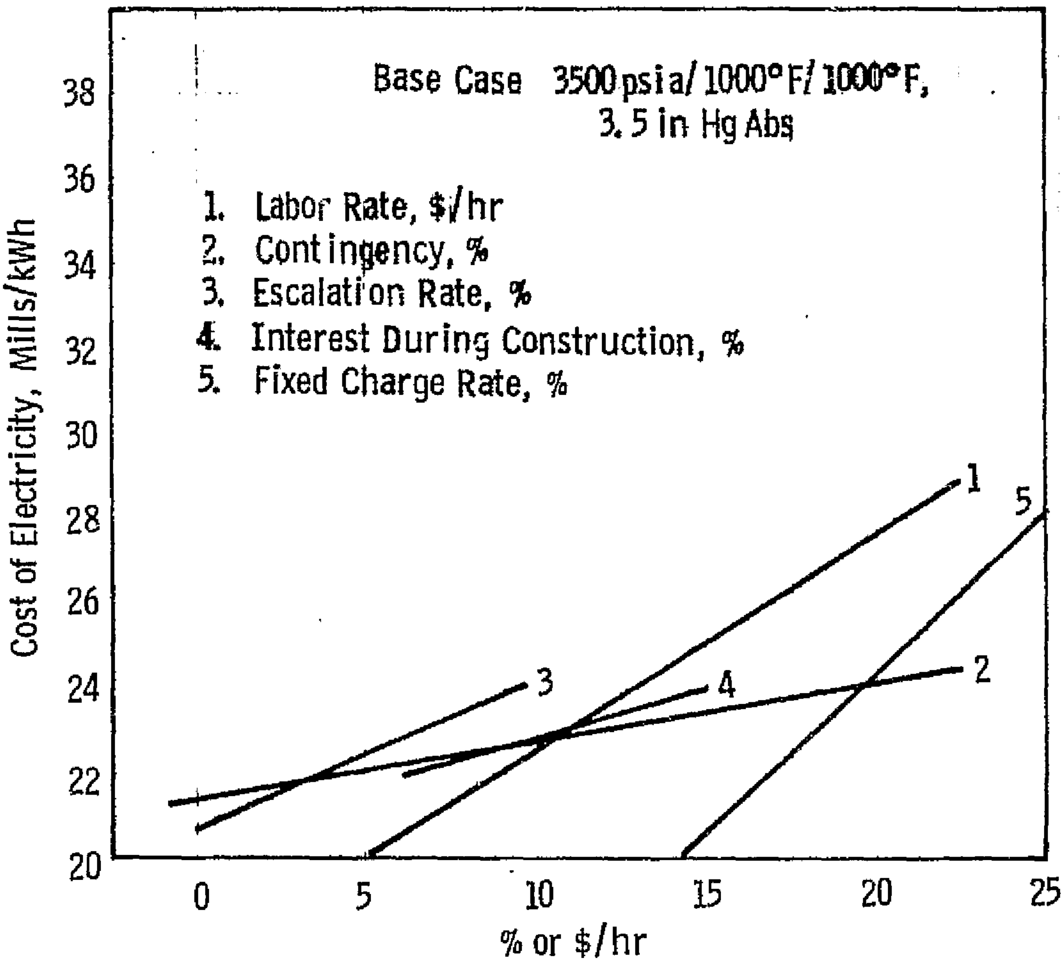

Fig. 12.68 —Effect of labor, indirect or fixed costs on the cost electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682414-A

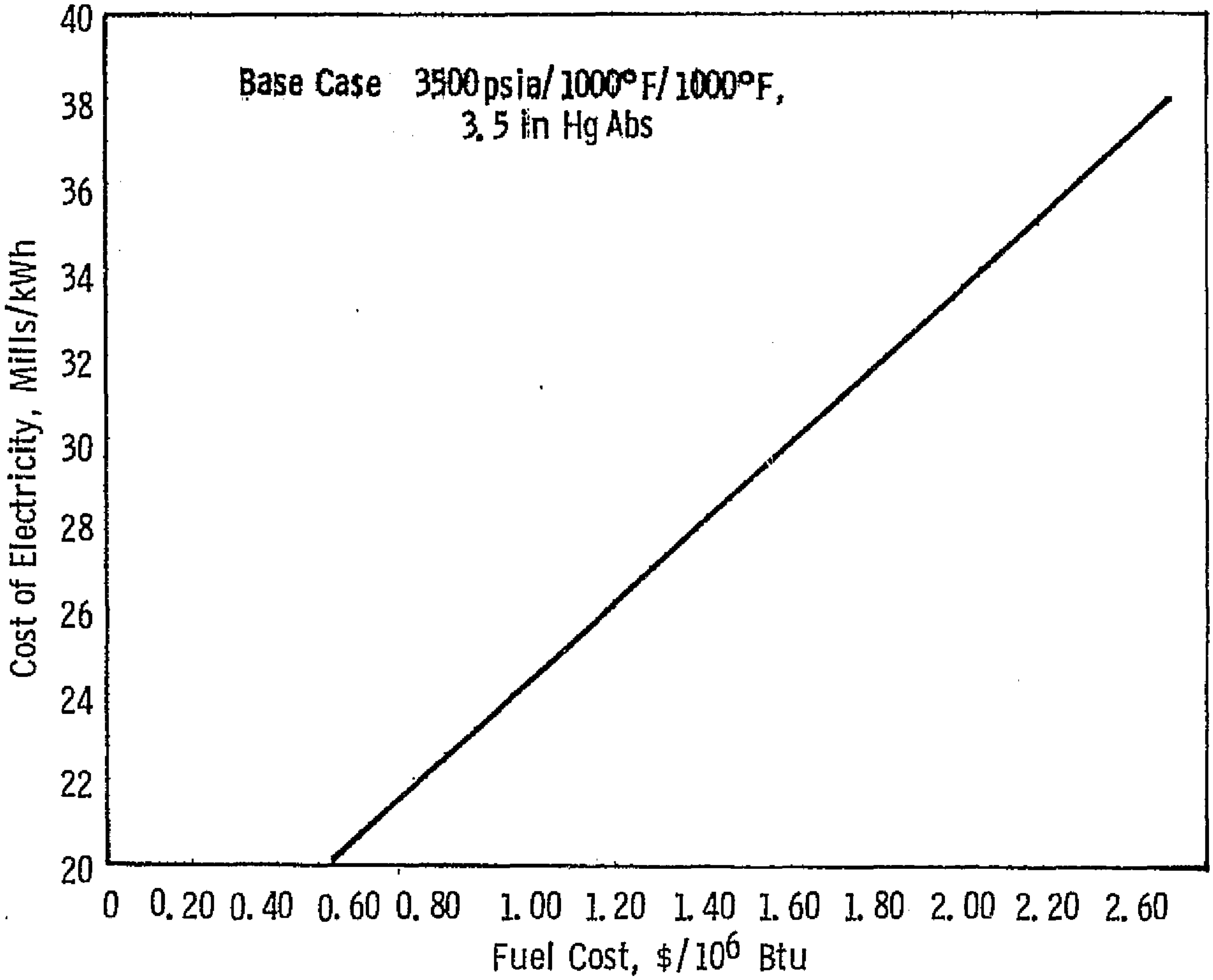

Fig. 12.69—Effect of fuel cost on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Curve 682401-A

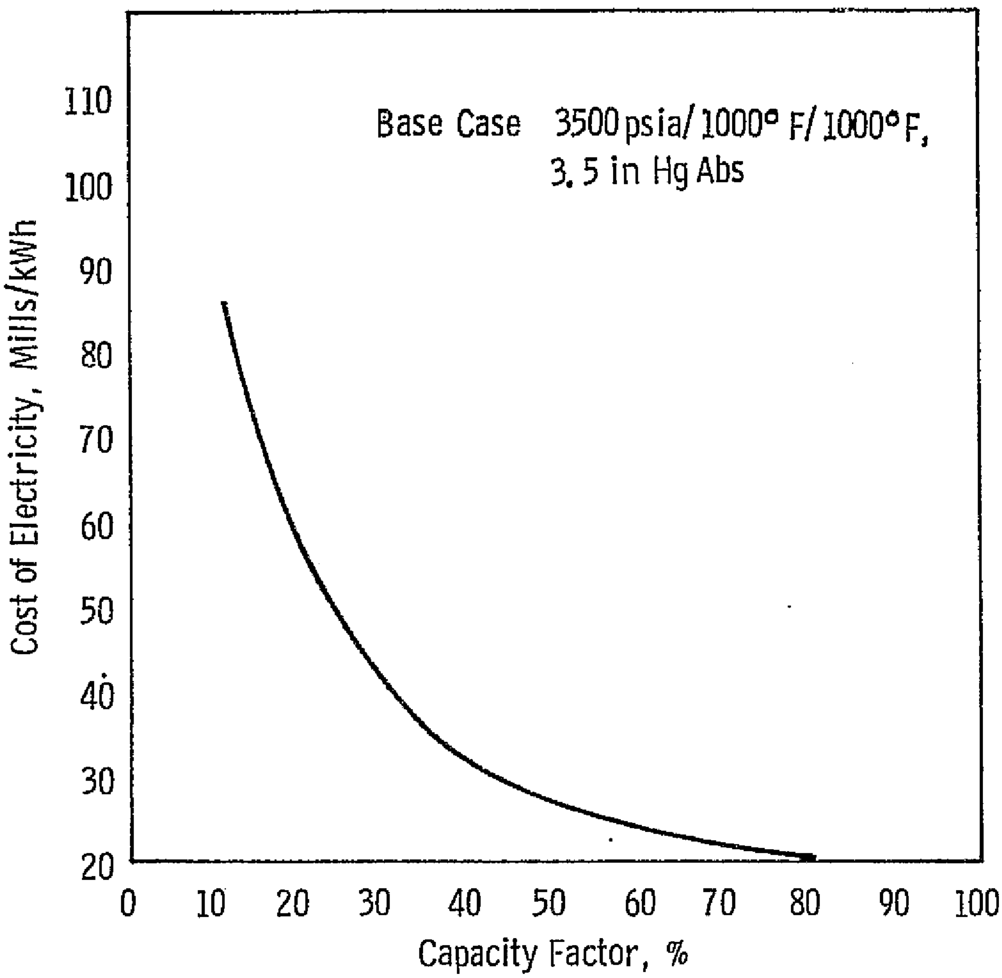

Fig. 12.70—Effect of capacity factor on the cost of electricity from a nominal 600 MWe steam plant with a pressurized fluidized bed boiler

Table 12.29 - ADVANCED STEAM CYCLE WITH ATM BOILER SUMMARY PLANT RESULTS

PLANT RESULT BREAKDOWN

PARAMETRIC POINT	1	2	3	4	5	6	7	8
TOTAL CAPITAL COST ,M$	733.11	729.50	740.67	252.42	251.47	212.22	396.32	395.39
STM TURB-GEN & FEED STRING ,M$	126.561	126.561	126.561	26.732	19.112	19.112	67.467	65.847
STEAM BOILER ,M$	130.257	130.267	130.267	22.667	23.367	24.000	37.467	38.367
STEAM PIPING ,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST ,M$	226.820	226.828	226.828	43.399	42.479	43.112	104.934	104.214
TOT MAJOR COMPONENT COST ,$/KWE	499.653	498.751	495.855	93.569	91.606	92.648	225.690	224.167
BALANCE OF PLANT COST ,$/KWE	109.223	108.716	125.428	107.230	107.159	88.159	127.015	127.336
SITE LABOR ,$/KWE	187.304	187.203	188.756	85.647	87.259	63.903	109.173	109.751
TOTAL DIRECT COST ,$/KWE	785.184	784.671	810.039	287.446	286.022	244.710	461.877	461.254
INDIRECT COSTS ,$/KWE	95.525	95.474	96.266	44.130	44.501	32.590	55.678	55.973
PROF & OWNER COSTS ,$/KWE	62.815	62.774	64.803	22.996	22.882	19.577	36.950	36.900
CONTINGENCY COST ,$/KWE	70.657	70.620	72.904	22.996	22.892	19.577	36.950	36.900
ESCALATION COST ,$/KWE	254.953	254.789	262.450	77.422	77.147	64.880	121.262	121.174
INT DURING CONSTRUCTION ,$/KWE	303.736	303.591	312.667	89.181	88.864	74.734	139.679	139.577
TOTAL CAPITALIZATION ,$/KWE	1572.880	1571.869	1619.128	544.229	542.298	456.068	852.397	851.778
COST OF ELEC-CAPITAL ,MILLS/KWE	49.722	49.690	51.194	17.204	17.143	14.417	26.946	26.927
COST OF ELEC-FUEL ,MILLS/KWE	7.861	8.073	8.739	7.930	8.146	8.202	7.429	7.618
COST OF ELEC-OP&MAIN ,MILLS/KWE	1.132	1.145	1.111	1.139	1.152	2.068	1.106	1.118
TOTAL COST OF ELEC ,MILLS/KWE	58.715	58.908	61.035	26.273	26.441	24.687	35.481	35.663
COE 0.5 CAP. FACTOR ,MILLS/KWE	73.632	73.816	76.390	31.434	31.584	29.012	43.565	43.741
COE 0.8 CAP. FACTOR ,MILLS/KWE	49.392	49.592	51.438	23.047	23.227	21.984	30.429	30.614
COE 1.2XCAP. COST ,MILLS/KWE	58.659	68.846	71.271	29.714	29.870	27.571	40.870	41.048
COE 1.2XFUEL COST ,MILLS/KWE	60.287	60.523	62.782	27.859	28.070	26.327	36.967	37.186
COE (CONTINGENCY=0) ,MILLS/KWE	55.251	55.446	57.460	25.225	25.399	23.795	33.798	33.982
COE (ESCALATION=0) ,MILLS/KWE	49.012	49.212	51.046	23.417	23.595	22.294	31.008	31.192

PLANT RESULT BREAKDOWN

PARAMETRIC POINT	9	10	11	12	13	14	15	16
TOTAL CAPITAL COST ,M$	325.76	593.93	587.46	472.31	355.55	381.38	239.12	236.54
STM TURB-GEN & FEED STRING ,M$	65.847	123.967	122.347	122.347	56.854	70.954	18.289	16.770
STEAM BOILER ,M$	30.000	50.267	58.857	35.500	33.267	33.267	20.567	21.067
STEAM PIPING ,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST ,M$	95.847	184.234	181.214	157.847	90.121	104.221	38.856	37.837
TOT MAJOR COMPONENT COST ,$/KWE	205.499	395.513	389.044	337.830	193.969	224.261	83.800	81.559
BALANCE OF PLANT COST ,$/KWE	106.727	160.740	161.678	139.809	115.072	114.960	105.228	104.181
SITE LABOR ,$/KWE	73.321	143.398	141.480	88.227	103.292	105.346	82.968	82.830
TOTAL DIRECT COST ,$/KWE	385.546	699.651	692.203	565.866	412.333	444.567	271.995	268.571
INDIRECT COSTS ,$/KWE	37.394	73.133	72.155	44.996	52.679	53.726	42.314	42.244
PROF & OWNER COSTS ,$/KWE	30.844	55.972	55.376	45.269	32.987	35.565	21.760	21.486
CONTINGENCY COST ,$/KWE	30.344	55.972	55.376	45.269	32.987	35.565	21.760	21.486
ESCALATION COST ,$/KWE	99.359	181.389	179.417	143.803	108.864	116.744	73.363	72.534
INT DURING CONSTRUCTION ,$/KWE	114.450	208.938	206.667	165.643	125.398	134.476	84.505	83.550
TOTAL CAPITALIZATION ,$/KWE	698.436	1275.055	1261.193	1010.847	765.247	820.644	515.696	509.870
COST OF ELEC-CAPITAL ,MILLS/KWE	22.079	40.307	39.859	31.955	24.191	25.942	16.302	16.118
COST OF ELEC-FUEL ,MILLS/KWE	7.661	7.063	7.231	7.264	7.600	7.540	8.001	8.206
COST OF ELEC-OP&MAIN ,MILLS/KWE	1.979	1.093	1.093	1.905	1.117	1.113	1.143	1.152
TOTAL COST OF ELEC ,MILLS/KWE	31.714	48.453	48.193	41.124	32.908	34.596	25.446	25.476
COE 0.5 CAP. FACTOR ,MILLS/KWE	39.337	59.545	59.154	50.710	49.166	42.378	30.337	30.312
COE 0.8 CAP. FACTOR ,MILLS/KWE	27.574	40.896	40.718	35.132	28.373	29.732	22.390	22.459
COE 1.2XCAP. COST ,MILLS/KWE	36.130	56.515	56.167	47.515	37.747	39.784	28.707	28.700
COE 1.2XFUEL COST ,MILLS/KWE	33.246	49.866	49.640	42.576	34.428	36.104	27.047	27.117
COE (CONTINGENCY=0) ,MILLS/KWE	30.309	45.903	45.670	39.061	31.406	32.975	24.455	24.497
COE (ESCALATION=0) ,MILLS/KWE	28.048	41.761	41.574	35.818	28.892	30.289	22.740	22.800

Table 12.29 ADVANCED STEAM CYCLE WITH ATM BOILER SUMMARY PLANT RESULTS
Continued

PLANT RESULTS BREAKDOWN

PARAMETRIC POINT		17	18	19	20	21	22	23	24
TOTAL CAPITAL COST	,M$	353.09	318.52	232.82	231.06	252.36	289.98	288.11	252.57
STM TURB-GEN & FEED STRING	,M$	56.854	52.793	17.044	15.525	19.137	38.444	36.525	36.525
STEAM BOILER	,M$	33.267	24.367	19.367	19.867	21.167	22.367	22.967	23.800
STEAM PIPING	,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST	,M$	90.121	77.160	36.411	35.392	40.304	60.811	59.492	60.325
TOT MAJOR COMPONENT COST	,$/KWE	193.946	166.163	78.576	76.392	88.323	130.918	128.095	129.454
BALANCE OF PLANT COST	,$/KWE	113.299	111.738	104.658	104.366	122.172	117.154	117.269	98.299
SITE LABOR	,$/KWE	102.301	91.964	81.486	81.670	83.571	87.071	87.313	66.999
TOTAL DIRECT COST	,$/KWE	409.547	369.865	264.721	262.428	294.066	335.144	332.677	294.752
INDIRECT COSTS	,$/KWE	52.174	46.901	41.558	41.652	42.621	44.406	44.530	34.170
PROF & OWNER COSTS	,$/KWE	32.764	29.589	21.178	20.994	23.525	26.811	26.614	23.580
CONTINGENCY COST	,$/KWE	32.764	29.589	21.178	20.994	23.525	26.811	26.614	23.580
ESCALATION COST	,$/KWE	108.097	97.579	71.478	70.952	79.675	88.810	88.249	77.105
INT DURING CONSTRUCTION	,$/KWE	124.515	112.399	82.334	81.728	90.624	102.298	101.652	88.816
TOTAL CAPITALIZATION	,$/KWE	759.850	695.924	502.445	498.748	553.037	624.282	620.336	542.003
COST OF ELEC-CAPITAL	,MILLS/KWE	24.021	21.684	15.883	15.767	17.483	19.735	19.610	17.134
COST OF ELEC-FUEL	,MILLS/KWE	7.692	7.896	9.149	8.363	9.075	7.655	7.851	7.899
COST OF ELEC-OP&MAIN	,MILLS/KWE	1.118	1.135	1.153	1.166	1.127	1.121	1.133	2.016
TOTAL COST OF ELEC	,MILLS/KWE	32.831	30.715	25.185	25.295	27.685	28.511	28.594	27.049
COE 0.5 CAP. FACTOR	,MILLS/KWE	40.037	37.270	29.950	30.025	32.930	34.431	34.477	32.189
COE 0.8 CAP. FACTOR	,MILLS/KWE	29.327	26.649	22.207	22.339	24.407	24.811	24.917	23.836
COE 1.2XCAP. COST	,MILLS/KWE	37.635	35.052	28.362	28.448	31.181	32.458	32.516	30.476
COE 1.2XFUEL COST	,MILLS/KWE	34.363	32.294	25.815	25.968	29.500	30.042	30.165	28.629
COE (CONTINGENCY=0)	,MILLS/KWE	31.339	29.367	24.220	24.339	26.613	27.289	27.382	25.975
COE (ESCALATION=0)	,MILLS/KWE	29.843	27.115	22.548	22.678	24.782	25.234	25.339	24.204

PARAMETRIC POINT		25	26	27	28	29	30	31	32
TOTAL CAPITAL COST	,M$	378.95	378.16	347.01	263.43	296.28	324.88	288.99	345.27
STM TURB-GEN & FEED STRING	,M$	70.056	68.437	68.937	27.556	28.144	48.756	48.756	52.444
STEAM BOILER	,M$	25.567	26.167	30.400	21.567	22.967	23.967	26.300	24.967
STEAM PIPING	,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST	,M$	95.623	94.604	99.337	49.223	51.111	72.723	75.056	77.411
TOT MAJOR COMPONENT COST	,$/KWE	205.495	203.323	211.791	106.124	131.586	156.442	160.946	166.638
BALANCE OF PLANT COST	,$/KWE	143.212	143.744	123.525	110.696	123.690	129.067	108.887	143.370
SITE LABOR	,$/KWE	96.146	96.609	75.934	85.372	87.755	92.063	70.046	93.478
TOTAL DIRECT COST	,$/KWE	444.852	443.676	411.300	302.193	343.031	377.573	339.879	403.485
INDIRECT COSTS	,$/KWE	49.035	49.271	38.726	43.540	44.755	46.952	35.723	47.674
PROF & OWNER COSTS	,$/KWE	35.583	35.494	32.904	24.175	27.442	30.206	27.190	32.279
CONTINGENCY COST	,$/KWE	35.588	35.494	32.904	24.175	27.442	30.206	27.190	32.279
ESCALATION COST	,$/KWE	115.851	115.619	105.757	90.796	90.757	99.423	88.156	105.733
INT DURING CONSTRUCTION	,$/KWE	133.446	133.179	121.820	93.067	104.541	114.523	101.545	121.792
TOTAL CAPITALIZATION	,$/KWE	814.355	812.733	743.411	567.945	637.969	698.882	619.684	743.242
COST OF ELEC-CAPITAL	,MILLS/KWE	25.744	25.692	23.501	17.954	20.168	22.093	19.590	23.496
COST OF ELEC-FUEL	,MILLS/KWE	7.306	7.493	7.529	7.922	7.697	7.469	7.507	7.627
COST OF ELEC-OP&MAIN	,MILLS/KWE	1.098	1.110	1.951	1.138	1.123	1.109	1.948	1.119
TOTAL COST OF ELEC	,MILLS/KWE	34.149	34.292	32.981	27.014	28.988	30.671	29.045	32.242
COE 0.5 CAP. FACTOR	,MILLS/KWE	41.871	41.999	40.031	32.400	35.038	37.299	34.922	39.291
COE 0.8 CAP. FACTOR	,MILLS/KWE	29.321	29.474	28.574	23.647	25.206	26.529	25.372	27.837
COE 1.2XCAP. COST	,MILLS/KWE	39.296	39.430	37.681	30.605	33.021	35.090	32.963	36.941
COE 1.2XFUEL COST	,MILLS/KWE	35.619	35.790	34.497	28.539	30.527	32.165	30.546	33.767
COE (CONTINGENCY=0)	,MILLS/KWE	32.526	32.675	31.482	25.912	27.738	29.295	27.806	30.771
COE (ESCALATION=0)	,MILLS/KWE	29.874	30.026	29.079	24.033	25.640	27.003	25.792	28.341

Table 12.29 ADVANCED STEAM CYCLE WITH ATM BOILER SUMMARY PLANT RESULTS
Continued

	PARAMETRIC POINT		33	34	35	36	37	38	39	40
	TOTAL CAPITAL COST	,M$	311.54	232.92	245.14	203.02	223.23	231.99	223.00	220.18
P	STM TURB-GEN & FEED STRING	,M$	52.444	15.525	15.525	15.525	15.525	15.525	17.068	15.449
L	STEAM BOILER	,M$	27.303	21.157	23.957	22.400	24.567	27.157	16.567	16.967
A	STEAM PIPING	,M$	.000	.000	.000	.000	.000	.000	.000	.000
N										
T	TOT MAJOR COMPONENT COST	,M$	80.344	36.692	39.492	37.925	[illegible]0.092	42.692	33.635	32.416
R	TOT MAJOR COMPONENT COST	,$/KWE	172.399	78.797	95.350	81.563	95.093	91.942	72.659	7[illegible]16
E	BALANCE OF PLANT COST	,$/KWE	123.618	102.011	105.642	86.923	101.642	105.272	103.078	1[illegible]10
S	SITE LABOR	,$/KWE	72.130	92.151	86.895	64.389	69.932	73.512	78.096	7[illegible].959
U	TOTAL DIRECT COST	,$/KWE	368.137	272.960	277.597	232.880	256.573	267.726	253.822	250.195
L	INDIRECT COSTS	,$/KWE	36.797	41.937	44.316	32.939	35.104	35.961	39.824	39.764
T	PROF & OWNER COSTS	,$/KWE	29.451	21.037	22.207	18.630	20.526	21.418	20.306	20.016
B	CONTINGENCY COST	,$/KWE	29.451	21.037	22.207	19.630	20.526	21.418	20.306	20.016
R	ESCALATION COST	,$/KWE	95.095	71.128	75.103	62.117	68.217	71.045	68.530	67.655
E	INT DURING CONSTRUCTION	,$/KWE	109.537	91.531	96.510	71.552	79.579	81.835	78.939	77.931
A	TOTAL CAPITALIZATION	,$/KWE	668.458	499.990	527.929	436.647	479.524	499.403	481.726	475.576
K	COST OF ELEC-CAPITAL	,MILLS/KWE	21.131	15.806	16.689	13.803	15.159	15.787	15.228	15.034
D	COST OF ELEC-FUEL	,MILLS/KWE	7.670	8.296	6.648	8.424	8.296	8.648	8.308	8.522
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.976	.894	.912	2.107	.894	.912	1.157	1.170
W	TOTAL COST OF ELEC	,MILLS/KWE	30.777	24.996	26.250	24.334	24.349	25.348	24.694	24.727
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	37.117	29.737	31.256	28.475	28.896	30.084	29.262	29.237
	COE 0.8 CAP. FACTOR	,MILLS/KWE	26.815	22.032	23.120	21.746	21.506	22.388	21.838	21.908
	COE 1.2XCAP. COST	,MILLS/KWE	35.034	28.157	29.597	27.095	27.380	28.505	27.739	27.733
	COE 1.2XFUEL COST	,MILLS/KWE	32.311	26.655	27.979	26.019	26.008	27.078	26.355	26.431
	COE (CONTINGENCY=0)	,MILLS/KWE	29.436	24.037	25.238	23.485	23.414	24.372	23.769	23.815
	COE (ESCALATION=0)	,MILLS/KWE	27.269	22.372	23.479	22.042	21.832	22.727	22.165	22.231

	PARAMETRIC POINT		41	42	43	44	45	46	47	48
	TOTAL CAPITAL COST	,M$	193.37	241.79	281.17	278.38	245.28	300.67	334.80	296.33
P	STM TURB-GEN & FEED STRING	,M$	15.449	19.161	38.268	36.649	36.649	40.261	52.468	52.468
L	STEAM BOILER	,M$	21.630	18.157	20.157	20.757	22.300	22.157	23.567	24.100
A	STEAM PIPING	,M$	.000	.000	.000	.000	.000	.000	.000	.000
N										
T	TOT MAJOR COMPONENT COST	,M$	37.049	37.328	58.435	57.416	58.949	62.428	76.035	76.568
R	TOT MAJOR COMPONENT COST	,$/KWE	79.733	81.898	125.945	123.723	126.591	136.473	163.792	164.391
E	BALANCE OF PLANT COST	,$/KWE	85.236	120.620	114.780	113.883	95.481	132.750	136.303	117.068
S	SITE LABOR	,$/KWE	63.416	79.745	84.575	84.647	65.488	86.788	91.212	68.839
U	TOTAL DIRECT COST	,$/KWE	228.384	282.263	325.300	322.252	287.560	355.011	391.306	350.299
L	INDIRECT COSTS	,$/KWE	32.342	40.570	43.133	43.170	33.399	44.262	46.518	35.108
T	PROF & OWNER COSTS	,$/KWE	18.271	22.581	26.024	25.780	23.005	28.401	31.304	28.024
B	CONTINGENCY COST	,$/KWE	19.271	22.581	26.024	25.780	23.005	28.401	31.304	28.024
R	ESCALATION COST	,$/KWE	60.947	75.468	86.208	85.491	75.237	93.505	102.600	90.508
E	INT DURING CONSTRUCTION	,$/KWE	70.203	86.929	99.301	98.475	86.664	107.707	118.183	104.254
A	TOTAL CAPITALIZATION	,$/KWE	428.418	530.492	605.990	600.948	528.869	657.287	721.216	636.217
K	COST OF ELEC-CAPITAL	,MILLS/KWE	13.543	16.770	19.157	18.997	16.719	20.778	22.799	20.112
D	COST OF ELEC-FUEL	,MILLS/KWE	8.587	9.245	7.843	8.040	8.093	8.701	7.794	7.840
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	2.130	1.130	1.127	1.139	2.044	1.103	1.124	2.000
W	TOTAL COST OF ELEC	,MILLS/KWE	24.260	27.145	28.127	28.177	26.856	30.582	31.717	29.953
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	28.323	32.176	33.874	33.875	31.971	36.816	38.557	35.986
	COE 0.8 CAP. FACTOR	,MILLS/KWE	21.721	24.000	24.536	24.615	23.721	26.686	27.442	26.182
	COE 1.2XCAP. COST	,MILLS/KWE	26.969	30.499	31.959	31.976	30.199	34.739	36.277	33.975
	COE 1.2XFUEL COST	,MILLS/KWE	25.978	28.994	29.696	29.785	29.474	32.322	33.276	31.521
	COE (CONTINGENCY=0)	,MILLS/KWE	23.428	26.116	26.942	27.002	25.807	29.288	30.291	28.676
	COE (ESCALATION=0)	,MILLS/KWE	22.012	24.361	24.947	25.023	24.080	27.133	27.932	26.614

Table 12.29 ADVANCED STEAM CYCLE WITH ATM BOILER SUMMARY PLANT RESULTS
Continued

PLANT RESULT BREAKDOWN

PARAMETRIC POINT		49	50	51	52	53	54	55	56
TOTAL CAPITAL COST	,M$	252.84	313.82	312.18	334.71	412.81	413.01	609.72	611.73
STM TURB-GEN & FEED STRING	,M$	27.691	48.781	47.151	50.749	32.942	31.299	82.567	80.923
STEAM BOILER	,M$	18.967	22.067	22.567	24.160	38.060	39.160	62.960	64.460
STEAM PIPING	,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST	,M$	45.693	73.848	59.728	74.909	71.002	70.458	145.527	145.383
TOT MAJOR COMPONENT COST	,$/KWE	100.625	152.516	150.127	163.519	85.012	84.383	173.811	173.671
BALANCE OF PLANT COST	,$/KWE	137.622	123.075	123.131	141.139	91.516	91.549	110.687	111.368
SITE LABOR	,$/KWE	81.962	89.263	89.418	91.958	73.937	74.496	91.950	92.587
TOTAL DIRECT COST	,$/KWE	290.238	354.854	352.736	396.616	250.465	250.427	376.449	377.627
INDIRECT COSTS	,$/KWE	41.800	45.524	45.603	46.899	37.708	37.993	46.895	47.219
PROF & OWNER COSTS	,$/KWE	23.217	29.198	29.319	31.729	20.037	20.034	30.116	30.210
CONTINGENCY COST	,$/KWE	23.217	29.180	29.019	31.729	21.394	21.391	32.155	32.256
ESCALATION COST	,$/KWE	77.599	96.135	95.618	103.941	75.775	75.839	111.641	112.032
INT DURING CONSTRUCTION	,$/KWE	89.373	110.702	110.140	119.727	88.891	88.956	130.965	131.423
TOTAL CAPITALIZATION	,$/KWE	545.403	575.562	572.135	730.641	494.270	494.630	728.220	730.766
COST OF ELEC-CAPITAL	,MILLS/KWE	17.241	21.356	21.248	23.097	15.625	15.636	23.021	23.101
COST OF ELEC-FUEL	,MILLS/KWE	9.049	7.637	7.834	8.444	7.970	8.113	7.368	7.593
COST OF ELEC-OP&MAIN	,MILLS/KWE	1.140	1.114	1.126	1.091	.864	.879	.832	.846
TOTAL COST OF ELEC	,MILLS/KWE	26.431	30.107	30.208	32.632	24.359	24.629	31.221	31.540
COE 0.5 CAP. FACTOR	,MILLS/KWE	31.603	36.514	36.582	39.561	29.047	29.320	38.127	38.471
COE 0.8 CAP. FACTOR	,MILLS/KWE	23.198	25.103	26.224	28.302	21.430	21.697	26.904	27.209
COE 1.2XCAP. COST	,MILLS/KWE	29.879	34.378	34.458	37.252	27.484	27.756	35.825	36.161
COE 1.2XFUEL COST	,MILLS/KWE	28.040	31.634	31.775	34.321	25.933	26.251	32.694	33.059
COE (CONTINGENCY=0)	,MILLS/KWE	25.373	28.777	28.886	31.187	23.345	23.615	29.696	30.011
COE (ESCALATION=0)	,MILLS/KWE	23.553	25.552	25.680	28.799	21.516	21.784	27.032	27.337

PLANT RESULT BREAKDOWN

PARAMETRIC POINT		57	58	59	60	61	62	63	64
TOTAL CAPITAL COST	,M$	891.49	881.38	394.60	393.90	495.21	494.21	385.58	381.11
STM TURB-GEN & FEED STRING	,M$	142.354	139.863	29.777	28.258	68.789	67.046	28.292	26.763
STEAM BOILER	,M$	101.260	98.960	34.460	35.360	39.860	40.860	32.560	33.360
STEAM PIPING	,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST	,M$	243.614	239.823	54.237	63.618	108.649	107.906	60.842	60.123
TOT MAJOR COMPONENT COST	,$/KWE	290.437	234.799	76.935	76.212	129.939	129.074	72.932	71.921
BALANCE OF PLANT COST	,$/KWE	144.943	146.001	90.837	90.505	97.686	97.431	90.537	88.829
SITE LABOR	,$/KWE	120.180	118.678	71.405	71.849	77.392	77.737	70.254	69.637
TOTAL DIRECT COST	,$/KWE	555.550	599.479	239.177	238.565	305.017	304.242	233.723	230.387
INDIRECT COSTS	,$/KWE	61.292	60.526	36.416	36.643	39.470	39.646	35.830	35.515
PROF & OWNER COSTS	,$/KWE	44.445	43.958	19.134	19.085	24.401	24.339	18.698	18.431
CONTINGENCY COST	,$/KWE	47.454	46.935	20.430	20.378	26.054	25.987	19.964	19.679
ESCALATION COST	,$/KWE	152.940	151.134	72.454	72.342	90.796	90.629	70.858	69.891
INT DURING CONSTRUCTION	,$/KWE	191.143	189.025	84.995	84.863	106.512	106.315	83.122	81.989
TOTAL CAPITALIZATION	,$/KWE	1062.833	1051.057	472.505	471.876	592.249	591.158	462.194	455.892
COST OF ELEC-CAPITAL	,MILLS/KWE	33.599	33.226	14.940	14.917	18.722	18.688	14.611	14.412
COST OF ELEC-FUEL	,MILLS/KWE	7.013	7.217	7.942	8.178	7.640	7.868	8.101	8.322
COST OF ELEC-OP&MAIN	,MILLS/KWE	.811	.823	.869	.883	.850	.864	.879	.878
TOTAL COST OF ELEC	,MILLS/KWE	41.423	41.256	23.751	23.973	27.212	27.419	23.590	23.611
COE 0.5 CAP. FACTOR	,MILLS/KWE	51.508	51.233	28.233	28.453	32.829	33.025	27.974	27.935
COE 0.8 CAP. FACTOR	,MILLS/KWE	35.120	35.035	20.950	21.181	23.702	23.915	20.851	20.909
COE 1.2XCAP. COST	,MILLS/KWE	48.148	47.911	26.739	26.961	30.956	31.157	26.513	26.493
COE 1.2XFUEL COST	,MILLS/KWE	42.932	42.709	25.339	25.614	29.740	28.993	25.211	25.275
COE (CONTINGENCY=0)	,MILLS/KWE	39.179	39.041	22.782	23.012	25.977	26.187	22.644	22.678
COE (ESCALATION=0)	,MILLS/KWE	35.315	35.220	21.032	21.264	23.805	24.019	20.932	20.989

Table 12.29 ADVANCED STEAM CYCLE WITH ATM BOILER SUMMARY PLANT RESULTS
Continued

PARAMETRIC POINT	65	66	67	68	69	70	71	72
TOTAL CAPITAL COST ,M$	469.56	453.99	589.12	588.66	359.71	367.76	430.25	429.28
STM TURB-GEN & FEED STRING ,M$	52.895	51.151	88.095	86.351	28.954	27.211	53.442	51.823
STEAM BOILER ,M$	37.550	38.560	42.950	43.960	27.850	28.560	33.960	34.860
STEAM PIPING ,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST ,M$	90.455	89.711	131.055	130.311	56.814	55.771	87.402	86.683
TOT MAJOR COMPONENT COST,$/KWE	108.173	107.300	153.441	155.603	69.148	66.913	104.600	103.776
BALANCE OF PLANT COST ,$/KWE	103.027	103.006	128.958	129.696	88.917	88.589	86.604	86.304
SITE LABOR ,$/KWE	74.257	74.599	80.903	81.320	67.256	67.447	71.942	72.336
TOTAL DIRECT COST ,$/KWE	285.453	284.904	366.302	366.620	224.321	222.946	263.146	262.416
INDIRECT COSTS ,$/KWE	37.871	38.045	41.251	41.473	34.300	34.399	36.691	36.892
PROF & OWNER COSTS ,$/KWE	22.836	22.792	29.304	29.330	17.946	17.836	21.052	20.993
CONTINGENCY COST ,$/KWE	24.393	24.336	31.238	31.316	19.161	19.043	22.477	22.415
ESCALATION COST ,$/KWE	85.187	85.079	107.527	107.761	67.987	67.641	78.939	78.789
INT DURING CONSTRUCTION ,$/KWE	99.931	99.805	126.256	126.414	79.755	79.349	92.602	92.427
TOTAL CAPITALIZATION ,$/KWE	555.660	554.962	702.039	702.913	443.470	441.214	514.906	513.932
COST OF ELEC-CAPITAL,MILLS/KWE	17.556	17.544	22.193	22.221	14.019	13.948	16.277	16.247
COST OF ELEC-FUEL ,MILLS/KWE	7.615	7.839	7.275	7.486	8.258	8.490	7.800	8.024
COST OF ELEC-OP&MAIN,MILLS/KWE	.849	.852	.827	.840	.883	.897	.854	.868
TOTAL COST OF ELEC ,MILLS/KWE	26.029	26.245	30.294	30.547	23.160	23.335	24.931	25.138
COE 0.5 CAP. FACTOR ,MILLS/KWE	31.293	31.508	36.952	37.213	27.366	27.519	29.815	30.012
COE 0.8 CAP. FACTOR ,MILLS/KWE	22.736	22.955	26.133	26.380	20.531	20.719	21.879	22.092
COE 1.2XCAP. COST ,MILLS/KWE	29.542	29.753	34.733	34.991	25.964	26.124	28.187	28.388
COE 1.2XFUEL COST ,MILLS/KWE	27.552	27.812	31.749	32.044	24.812	25.033	26.491	26.743
COE (CONTINGENCY=0) ,MILLS/KWE	24.873	25.091	28.811	29.062	22.252	22.432	23.866	24.076
COE (ESCALATION=0) ,MILLS/KWE	22.833	23.052	26.256	26.504	20.609	20.797	21.970	22.182

PARAMETRIC POINT	73	74	75	76	77	78	79	80
TOTAL CAPITAL COST ,M$	.00	.00	.00	.00	.00	.00	.00	.00
STM TURB-GEN & FEED STRING ,M$	.000	.000	.000	.000	.000	.000	.000	.000
STEAM BOILER ,M$	.000	.000	.000	.000	.000	.000	.000	.000
STEAM PIPING ,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST ,M$	.000	.000	.000	.000	.000	.000	.000	.000
TOT MAJOR COMPONENT COST,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
BALANCE OF PLANT COST ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
SITE LABOR ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
TOTAL DIRECT COST ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
INDIRECT COSTS ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
PROF & OWNER COSTS ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
CONTINGENCY COST ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
ESCALATION COST ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
INT DURING CONSTRUCTION ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
TOTAL CAPITALIZATION ,$/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COST OF ELEC-CAPITAL,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COST OF ELEC-FUEL ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COST OF ELEC-OP&MAIN,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
TOTAL COST OF ELEC ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COE 0.5 CAP. FACTOR ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COE 0.8 CAP. FACTOR ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COE 1.2XCAP. COST ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COE 1.2XFUEL COST ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COE (CONTINGENCY=0) ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000
COE (ESCALATION=0) ,MILLS/KWE	.000	.000	.000	.000	.000	.000	.000	.000

Table 12.30 -
PRESSURIZED BOILER ADVANCED STEAM SYSTEM SUMMARY PLANT RESULTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
TOTAL CAPITAL COST ,M$	403.72	352.67	331.66	400.76	353.67	332.44	434.07	356.10
STEAM TURB-GEN-FEED STRING ,M$	17.367	14.925	12.084	17.367	14.925	11.984	17.591	15.025
GAS TURBINE GENERATOR ,M$	14.000	13.500	13.300	14.300	14.000	13.800	16.000	15.800
PRESSURIZED BOILER ,M$	8.710	8.060	7.410	8.190	7.670	7.020	7.540	7.150
STACK GAS COOLER ,M$	3.300	3.400	4.100	3.400	3.400	3.800	3.300	3.500
TOT MAJOR COMPONENT COST ,M$	43.377	39.895	35.834	43.257	39.995	36.604	44.431	41.475
TOT MAJOR COMPONENT COST,$/KWE	65.064	68.735	76.197	64.762	68.750	75.283	67.123	72.382
BALANCE OF PLANT COST ,$/KWE	140.611	141.483	142.553	140.124	141.261	142.780	141.696	142.743
SITE LABOR ,$/KWE	89.028	91.179	94.716	89.134	91.346	94.783	90.592	93.295
TOTAL DIRECT COST ,$/KWE	294.703	301.397	313.567	294.020	301.358	312.847	299.411	308.421
INDIRECT COSTS ,$/KWE	45.404	46.501	48.305	45.459	46.587	48.340	46.202	47.581
PROF & OWNER COSTS ,$/KWE	23.576	24.112	25.035	23.522	24.109	25.028	23.953	24.674
CONTINGENCY COST ,$/KWE	26.276	26.444	26.945	26.220	26.448	26.896	26.675	27.022
ESCALATION COST ,$/KWE	95.483	95.919	96.141	96.333	95.975	96.035	97.907	97.905
INT DURING CONSTRUCTION ,$/KWE	114.623	113.403	112.977	114.448	113.482	112.870	116.284	115.704
TOTAL CAPITALIZATION ,$/KWE	501.053	507.774	523.013	500.002	507.959	522.016	510.431	521.306
COST OF ELEC-CAPITAL,MILLS/KWE	19.001	19.213	19.695	18.967	19.219	19.663	19.297	19.641
COST OF ELEC-FUEL ,MILLS/KWE	9.152	9.127	8.057	8.155	9.147	8.099	8.293	8.280
COST OF ELEC-OP&MAIN,MILLS/KWE	1.562	1.620	1.629	1.563	1.621	1.702	1.582	1.645
TOTAL COST OF ELEC ,MILLS/KWE	29.715	29.961	29.381	28.695	29.985	29.462	29.172	29.566
COE 0.5 CAP. FACTOR ,MILLS/KWE	34.416	34.725	35.359	34.385	34.753	35.361	34.961	35.458
COE 0.8 CAP. FACTOR ,MILLS/KWE	25.153	25.359	25.758	25.139	25.394	25.776	25.554	25.883
COE 1.2XCAP. COST ,MILLS/KWE	32.516	32.804	33.390	32.488	32.831	33.395	33.032	33.494
COE 1.2XFUEL COST ,MILLS/KWE	30.345	30.595	31.352	30.327	30.617	31.082	30.831	31.222
COE (CONTINGENCY=0) ,MILLS/KWE	27.435	27.686	28.169	27.417	27.712	28.122	27.873	28.264
COE (ESCALATION=0) ,MILLS/KWE	25.053	25.335	25.839	25.039	25.360	25.853	25.457	25.857

PARAMETRIC POINT	9	10	11	12	13	14	15	16
TOTAL CAPITAL COST ,M$	304.00	400.71	352.37	295.93	420.63	372.88	321.18	425.38
STEAM TURB-GEN-FEED STRING ,M$	12.203	17.591	15.143	12.203	17.219	14.775	11.960	17.242
GAS TURBINE GENERATOR ,M$	15.400	16.000	15.700	15.400	17.500	16.800	16.500	18.500
PRESSURIZED BOILER ,M$	6.630	7.150	6.760	6.370	9.710	8.060	7.410	8.190
STACK GAS COOLER ,M$	3.600	3.600	3.300	3.500	4.500	4.500	4.400	4.000
TOT MAJOR COMPONENT COST ,M$	37.839	44.341	40.909	37.479	47.928	44.135	40.270	47.932
TOT MAJOR COMPONENT COST,$/KWE	79.237	69.117	73.735	81.810	67.079	70.207	75.215	66.243
BALANCE OF PLANT COST ,$/KWE	144.844	145.064	146.876	149.406	133.879	134.301	134.674	133.998
SITE LABOR ,$/KWE	96.354	92.953	95.516	99.775	85.252	87.949	89.919	86.180
TOTAL DIRECT COST ,$/KWE	320.996	307.135	316.127	330.991	287.211	292.458	299.808	286.421
INDIRECT COSTS ,$/KWE	49.401	47.405	48.713	50.895	43.993	44.854	45.859	43.952
PROF & OWNER COSTS ,$/KWE	25.680	24.571	25.290	25.475	22.977	23.397	23.985	22.914
CONTINGENCY COST ,$/KWE	27.533	27.256	27.597	28.263	25.809	25.892	26.054	25.778
ESCALATION COST ,$/KWE	98.125	99.809	99.698	100.355	95.276	94.509	93.710	95.291
INT DURING CONSTRUCTION ,$/KWE	115.259	118.417	117.539	117.720	113.453	112.037	110.481	113.524
TOTAL CAPITALIZATION ,$/KWE	637.003	624.604	635.123	654.699	588.715	593.146	599.896	587.879
COST OF ELEC-CAPITAL,MILLS/KWE	20.137	19.745	20.073	20.639	18.511	18.751	18.964	18.584
COST OF ELEC-FUEL ,MILLS/KWE	8.274	8.538	8.570	8.595	7.744	7.689	7.603	7.760
COST OF ELEC-OP&MAIN,MILLS/KWE	1.734	1.623	1.599	1.797	1.479	1.524	1.587	1.477
TOTAL COST OF ELEC ,MILLS/KWE	30.145	29.911	30.345	31.028	27.832	27.964	28.154	27.822
COE 0.5 CAP. FACTOR ,MILLS/KWE	36.185	35.835	35.358	37.297	33.416	33.589	33.843	33.397
COE 0.8 CAP. FACTOR ,MILLS/KWE	26.369	26.209	26.581	27.207	24.343	24.448	24.598	24.337
COE 1.2XCAP. COST ,MILLS/KWE	34.172	33.860	34.351	35.227	31.555	31.714	31.947	31.539
COE 1.2XFUEL COST ,MILLS/KWE	31.799	31.619	32.059	32.807	29.391	29.502	29.675	29.374
COE (CONTINGENCY=0) ,MILLS/KWE	28.935	28.536	29.313	29.749	26.559	26.708	26.905	26.558
COE (ESCALATION=0) ,MILLS/KWE	26.459	26.127	26.593	27.323	24.208	24.384	24.622	24.195

Table 12.30 Continued -
PRESSURIZED BOILER ADVANCED STEAM SYSTEM SUMMARY PLANT RESULTS

	PARAMETRIC POINT		17	18	19	20	21	22	23	24
	TOTAL CAPITAL COST	,M$	376.16	323.06	432.63	387.36	329.86	432.26	382.00	327.83
P	STEAM TURB-GEN-FEED STRING	,M$	14.775	11.950	17.357	14.900	12.034	17.491	14.925	12.084
L	GAS TURBINE GENERATOR	,M$	17.700	17.200	20.800	20.200	19.200	21.200	20.400	19.500
A	PRESSURIZED BOILER	,M$	7.570	7.020	7.540	7.150	5.630	7.150	6.760	6.370
N	STACK GAS COOLER	,M$	4.400	4.300	3.400	5.400	4.300	3.400	3.500	4.100
T										
R	TOT MAJOR COMPONENT COST	,M$	44.545	40.480	49.107	47.650	42.214	49.241	45.585	42.054
E	TOT MAJOR COMPONENT COST	,$/KWE	70.133	74.835	66.992	74.557	77.841	68.400	72.417	79.384
S	BALANCE OF PLANT COST	,$/KWE	133.697	134.199	134.155	134.069	134.700	136.559	136.922	137.340
U	SITE LABOR	,$/KWE	87.873	89.277	86.195	89.787	91.107	87.812	89.877	92.807
L	TOTAL DIRECT COST	,$/KWE	291.704	298.311	287.343	298.413	303.648	292.771	299.217	309.531
T	INDIRECT COSTS	,$/KWE	44.913	45.531	43.360	45.791	45.465	44.794	45.837	47.331
	PROF & OWNER COSTS	,$/KWE	23.336	23.865	22.987	23.873	24.292	23.422	23.937	24.762
B	CONTINGENCY COST	,$/KWE	25.955	25.954	25.939	26.470	26.427	26.334	26.496	26.868
R	ESCALATION COST	,$/KWE	94.481	93.412	95.814	96.764	95.163	97.271	96.717	96.547
E	INT DURING CONSTRUCTION	,$/KWE	112.043	110.157	114.139	114.776	112.243	115.863	114.662	113.788
A	TOTAL CAPITALIZATION	,$/KWE	592.235	597.240	590.202	606.086	608.237	600.445	606.866	618.828
K	COST OF ELEC-CAPITAL	,MILLS/KWE	18.722	18.993	18.553	19.150	19.229	18.991	19.184	19.563
D	COST OF ELEC-FUEL	,MILLS/KWE	7.688	7.604	7.847	7.763	7.689	8.038	7.995	7.892
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.513	1.591	1.473	1.525	1.590	1.511	1.561	1.627
W	TOTAL COST OF ELEC	,MILLS/KWE	27.923	28.065	27.934	28.448	28.507	28.531	28.740	29.082
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	33.545	33.729	33.591	34.196	34.275	34.225	34.496	34.950
	COE 0.8 CAP. FACTOR	,MILLS/KWE	24.418	24.525	24.485	24.856	24.902	24.972	25.143	25.414
	COE 1.2XCAP. COST	,MILLS/KWE	31.673	31.841	31.715	32.280	32.352	32.327	32.577	32.994
	COE 1.2XFUEL COST	,MILLS/KWE	29.466	29.586	29.553	30.001	30.045	30.138	30.339	30.660
	COE (CONTINGENCY=0)	,MILLS/KWE	26.674	26.930	26.713	27.163	27.239	27.240	27.455	27.795
	COE (ESCALATION=0)	,MILLS/KWE	24.348	24.543	24.336	24.780	24.918	24.829	25.076	25.444

	PARAMETRIC POINT		25	26	27	28	29	30	31	32
	TOTAL CAPITAL COST	,M$	459.43	405.89	352.33	470.33	419.99	364.92	474.84	423.44
P	STEAM TURB-GEN-FEED STRING	,M$	16.953	14.551	11.860	16.993	14.551	11.860	17.118	14.775
L	GAS TURBINE GENERATOR	,M$	26.200	24.400	23.300	29.600	28.500	25.900	31.400	29.500
A	PRESSURIZED BOILER	,M$	8.190	7.670	7.020	7.540	7.020	6.630	6.630	6.760
N	STACK GAS COOLER	,M$	4.700	4.500	4.300	4.700	4.500	4.400	4.600	4.500
T										
R	TOT MAJOR COMPONENT COST	,M$	56.083	51.121	45.480	58.833	54.571	49.690	59.748	55.535
E	TOT MAJOR COMPONENT COST	,$/KWE	70.804	72.744	76.598	72.960	76.274	80.464	74.420	78.091
S	BALANCE OF PLANT COST	,$/KWE	126.745	126.653	125.193	125.135	125.201	125.873	127.634	127.582
U	SITE LABOR	,$/KWE	82.909	83.964	85.391	83.152	84.565	86.150	84.319	85.679
L	TOTAL DIRECT COST	,$/KWE	280.459	283.361	288.173	282.293	297.040	292.487	286.373	291.351
T	INDIRECT COSTS	,$/KWE	42.283	42.822	43.549	42.408	43.128	43.937	43.003	43.696
	PROF & OWNER COSTS	,$/KWE	22.437	22.659	23.354	22.584	22.963	23.399	22.910	23.308
B	CONTINGENCY COST	,$/KWE	25.502	25.407	25.400	25.723	25.790	25.832	26.082	26.160
R	ESCALATION COST	,$/KWE	94.822	93.489	92.240	95.753	94.986	93.889	97.049	96.279
E	INT DURING CONSTRUCTION	,$/KWE	113.320	111.251	109.203	114.506	113.103	111.222	116.038	114.620
A	TOTAL CAPITALIZATION	,$/KWE	578.822	578.999	581.625	583.271	597.010	590.755	591.954	595.414
K	COST OF ELEC-CAPITAL	,MILLS/KWE	18.299	18.303	18.386	18.439	18.557	18.675	18.697	18.822
D	COST OF ELEC-FUEL	,MILLS/KWE	7.338	7.250	7.148	7.358	7.237	7.177	7.493	7.426
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.381	1.418	1.465	1.376	1.412	1.459	1.394	1.432
W	TOTAL COST OF ELEC	,MILLS/KWE	27.017	26.985	26.999	27.173	27.256	27.312	27.584	27.680
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	32.507	32.477	32.515	32.704	32.823	32.915	33.193	33.327
	COE 0.8 CAP. FACTOR	,MILLS/KWE	23.537	23.554	23.552	23.715	23.777	23.812	24.078	24.151
	COE 1.2XCAP. COST	,MILLS/KWE	30.677	30.647	30.677	30.860	30.968	31.047	31.323	31.445
	COE 1.2XFUEL COST	,MILLS/KWE	28.435	28.439	28.423	28.644	28.714	28.747	29.082	29.165
	COE (CONTINGENCY=0)	,MILLS/KWE	25.759	25.743	25.771	25.901	25.993	26.061	26.295	26.400
	COE (ESCALATION=0)	,MILLS/KWE	23.333	23.432	23.503	23.515	23.543	23.757	23.878	24.018

Table 12.30 Continued -
PRESSURIZED BOILER ADVANCED STEAM SYSTEM SUMMARY PLANT RESULTS

	PARAMETRIC POINT		33	34	35	36	37	38	39	40
	TOTAL CAPITAL COST	,M$	367.59	476.71	423.04	364.89	431.96	383.26	330.66	436.19
P	STEAM TURB-GEN-FEED STRING	,M$	11.850	17.591	15.025	12.034	19.360	16.768	13.704	19.982
L	GAS TURBINE GENERATOR	,M$	27.900	31.900	29.800	27.600	18.500	17.700	17.200	18.500
A	PRESSURIZED BOILER	,M$	6.370	6.990	5.530	5.240	8.190	7.670	7.020	8.190
N	STACK GAS COOLER	,M$	4.400	4.600	4.500	4.400	4.000	4.400	4.300	4.000
T										
R	TOT MAJOR COMPONENT COST	,M$	50.530	60.981	55.955	50.324	50.050	46.538	42.224	50.672
E	TOT MAJOR COMPONENT COST	,$/KWE	92.500	79.131	82.259	86.299	68.349	71.868	76.284	74.287
S	BALANCE OF PLANT COST	,$/KWE	127.503	133.246	133.438	133.341	133.320	132.456	132.711	151.123
U	SITE LABOR	,$/KWE	97.405	93.264	99.750	91.597	85.726	87.005	88.918	89.486
L	TOTAL DIRECT COST	,$/KWE	297.409	300.641	305.456	311.217	287.393	291.331	297.913	314.897
T	INDIRECT COSTS	,$/KWE	44.577	45.915	45.773	46.709	43.720	44.373	45.348	45.638
	PROF & OWNER COSTS	,$/KWE	22.793	24.051	24.436	24.897	22.591	23.306	23.833	25.192
B	CONTINGENCY COST	,$/KWE	25.243	27.254	27.239	27.310	25.902	25.882	25.989	28.177
R	ESCALATION COST	,$/KWE	95.290	101.020	100.038	98.758	95.756	94.647	93.706	103.032
E	INT DURING CONSTRUCTION	,$/KWE	112.850	120.614	118.914	115.767	114.126	112.317	110.602	122.532
A	TOTAL CAPITALIZATION	,$/KWE	600.161	618.595	621.910	625.659	589.888	591.856	597.391	639.468
K	COST OF ELEC-CAPITAL	,MILLS/KWE	18.972	19.555	19.660	19.778	18.643	18.710	18.885	20.215
D	COST OF ELEC-FUEL	,MILLS/KWE	7.323	7.930	7.865	7.763	7.668	7.541	7.433	8.231
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.431	1.465	1.506	1.559	1.458	1.492	1.549	1.495
W	TOTAL COST OF ELEC	,MILLS/KWE	27.776	28.951	29.031	29.100	27.773	27.743	27.867	29.941
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	33.459	34.817	34.928	35.034	33.367	33.356	33.532	36.006
	COE 0.8 CAP. FACTOR	,MILLS/KWE	24.219	25.284	25.344	25.392	24.277	24.235	24.326	26.151
	COE 1.2XCAP. COST	,MILLS/KWE	31.571	32.862	32.962	33.055	31.503	31.485	31.644	33.984
	COE 1.2XFUEL COST	,MILLS/KWE	29.241	30.537	30.603	30.653	29.307	29.251	29.353	31.587
	COE (CONTINGENCY=0)	,MILLS/KWE	26.506	27.608	27.695	27.783	26.502	26.485	26.618	28.565
	COE (ESCALATION=0)	,MILLS/KWE	24.169	25.098	25.231	25.368	24.127	24.154	24.331	26.026

	PARAMETRIC POINT		41	42	43	44	45	46	47	48
	TOTAL CAPITAL COST	,M$	395.85	331.80	536.77	469.99	399.73	700.39	607.58	507.08
P	STEAM TURB-GEN-FEED STRING	,M$	17.142	13.953	55.658	47.960	39.189	100.651	86.649	70.679
L	GAS TURBINE GENERATOR	,M$	17.700	17.200	15.500	17.700	17.200	18.500	17.800	17.000
A	PRESSURIZED BOILER	,M$	7.670	7.020	10.920	9.890	8.840	17.030	14.950	12.610
N	STACK GAS COOLER	,M$	4.400	4.300	4.500	4.400	4.300	4.500	4.400	4.300
T										
R	TOT MAJOR COMPONENT COST	,M$	46.912	42.473	99.778	79.940	69.523	140.681	123.799	104.589
E	TOT MAJOR COMPONENT COST	,$/KWE	78.258	53.131	114.686	116.239	119.342	170.697	171.341	171.298
S	BALANCE OF PLANT COST	,$/KWE	150.670	150.517	133.519	138.844	139.721	168.327	165.802	163.227
U	SITE LABOR	,$/KWE	91.363	93.655	94.422	85.845	88.487	86.520	88.093	90.473
L	TOTAL DIRECT COST	,$/KWE	320.291	327.303	339.621	340.929	345.550	425.544	425.236	424.998
T	INDIRECT COSTS	,$/KWE	46.595	47.764	43.055	43.781	45.128	44.125	44.928	46.191
	PROF & OWNER COSTS	,$/KWE	25.523	28.194	27.030	27.279	27.724	34.043	34.019	34.000
B	CONTINGENCY COST	,$/KWE	28.231	28.320	30.750	30.493	30.405	38.872	38.248	37.486
R	ESCALATION COST	,$/KWE	102.034	100.973	112.174	110.052	109.275	139.855	136.222	131.806
E	INT DURING CONSTRUCTION	,$/KWE	120.858	118.894	134.002	130.874	128.013	167.384	162.257	156.078
A	TOTAL CAPITALIZATION	,$/KWE	643.633	649.439	595.532	583.412	595.095	849.833	840.910	830.509
K	COST OF ELEC-CAPITAL	,MILLS/KWE	20.346	20.530	21.676	21.604	21.689	26.865	26.583	26.254
D	COST OF ELEC-FUEL	,MILLS/KWE	8.149	8.051	7.153	7.125	7.093	6.855	6.836	6.805
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.542	1.607	1.366	1.412	1.478	1.306	1.352	1.419
W	TOTAL COST OF ELEC	,MILLS/KWE	30.039	30.188	30.213	30.142	30.251	35.035	34.771	34.479
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	36.139	36.347	36.713	36.623	36.757	43.096	42.746	42.355
	COE 0.8 CAP. FACTOR	,MILLS/KWE	26.219	26.339	26.195	26.091	26.194	29.999	29.787	29.556
	COE 1.2XCAP. COST	,MILLS/KWE	34.109	34.294	34.545	34.463	34.588	40.409	40.088	39.730
	COE 1.2XFUEL COST	,MILLS/KWE	31.653	31.798	31.544	31.557	31.657	36.409	36.138	35.840
	COE (CONTINGENCY=0)	,MILLS/KWE	28.669	28.835	28.694	28.653	28.785	33.111	32.897	32.665
	COE (ESCALATION=0)	,MILLS/KWE	26.172	25.397	25.330	25.951	26.153	29.691	29.588	29.491

Table 12.30 Continued -
PRESSURIZED BOILER ADVANCED STEAM SYSTEM SUMMARY PLANT RESULTS

PLANT RESULT BREAKDOWN

PARAMETRIC POINT		49	50	51	52	53	54	55	56
TOTAL CAPITAL COST	,M$	390.58	346.12	297.26	412.28	356.33	305.85	.00	.00
STEAM TURB-GEN-FEED STRING	,M$	17.242	14.775	11.953	17.242	14.775	11.960	.000	.000
GAS TURBINE GENERATOR	,M$	10.600	10.600	10.600	10.600	10.600	10.600	.000	.000
PRESSURIZED BOILER	,M$	8.130	7.670	7.020	8.190	7.570	7.020	.000	.000
STACK GAS COOLER	,M$	4.000	4.400	4.300	4.000	4.400	4.300	.000	.000
TOT MAJOR COMPONENT COST	,M$	40.032	37.445	33.880	40.032	37.445	33.880	.000	.000
TOT MAJOR COMPONENT COST	,$/KWE	55.272	58.932	62.609	55.363	59.029	62.711	.000	.000
BALANCE OF PLANT COST	,$/KWE	127.363	127.462	127.826	137.329	132.856	133.217	.000	.000
SITE LABOR	,$/KWE	79.792	81.582	93.337	84.643	84.351	86.170	.000	.000
TOTAL DIRECT COST	,$/KWE	262.416	267.976	273.823	277.335	276.236	282.098	.000	.000
INDIRECT COSTS	,$/KWE	42.699	41.607	42.527	43.168	43.019	43.947	.000	.000
PROF & OWNER COSTS	,$/KWE	20.993	21.438	21.906	22.187	22.099	22.568	.000	.000
CONTINGENCY COST	,$/KWE	23.617	23.753	23.824	24.960	24.485	24.544	.000	.000
ESCALATION COST	,$/KWE	87.411	86.902	85.919	92.422	89.613	88.546	.000	.000
INT DURING CONSTRUCTION	,$/KWE	104.136	103.056	131.329	110.106	106.270	104.429	.000	.000
TOTAL CAPITALIZATION	,$/KWE	539.262	544.731	545.326	570.178	561.721	566.132	.000	.000
COST OF ELEC-CAPITAL	,MILLS/KWE	17.047	17.220	17.365	18.025	17.757	17.897	.000	.000
COST OF ELEC-FUEL	,MILLS/KWE	7.714	7.646	7.563	7.899	7.829	7.744	.000	.000
COST OF ELEC-OP&MAIN	,MILLS/KWE	.848	.900	.969	.873	.924	.993	.000	.000
TOTAL COST OF ELEC	,MILLS/KWE	25.609	25.766	25.896	26.796	26.511	26.633	.000	.000
COE 0.5 CAP. FACTOR	,MILLS/KWE	30.724	30.932	31.106	32.204	31.938	32.002	.000	.000
COE 0.8 CAP. FACTOR	,MILLS/KWE	22.413	22.537	22.640	23.417	23.181	23.277	.000	.000
COE 1.2XCAP. COST	,MILLS/KWE	29.019	29.210	29.359	30.401	30.062	30.212	.000	.000
COE 1.2XFUEL COST	,MILLS/KWE	27.152	27.295	27.409	28.376	28.076	28.182	.000	.000
COE (CONTINGENCY=0)	,MILLS/KWE	24.452	24.613	24.754	25.573	25.322	25.456	.000	.000
COE (ESCALATION=0)	,MILLS/KWE	22.283	22.472	22.657	23.279	23.115	23.294	.000	.000

Table 12.31 - FLUIDIZED BED BOILER ADVANCED STEAM SYS SUMMARY PLANT RESULTS

	PARAMETRIC POINT		1	2	3	4	5	6	7	8
	TOTAL CAPITAL COST	M$	316.57	262.82	216.07	304.14	254.94	210.34	300.33	252.43
P	STEAM TURB-GEN-FEED STRING	M$	18.339	14.302	10.140	18.339	14.302	10.140	18.339	14.302
L	GAS TURBINE GENERATOR	M$	11.400	11.300	11.100	12.600	12.400	12.200	13.100	13.000
A	FLUIDIZED BED BOILER	M$	32.159	26.178	22.622	27.448	22.915	19.970	25.952	21.897
N	STACK GAS COOLER	M$	4.100	4.100	4.000	3.900	3.900	3.900	3.800	3.800
T										
R	TOT MAJOR COMPONENT COST	M$	66.008	55.880	47.862	62.287	53.517	46.210	61.191	52.999
E	TOT MAJOR COMPONENT COST	$/KWE	94.822	100.237	113.801	87.999	94.273	107.568	86.174	93.020
S	BALANCE OF PLANT COST	$/KWE	66.610	69.516	73.487	65.900	68.678	72.420	65.807	68.565
U	SITE LABOR	$/KWE	77.077	91.279	91.071	71.674	76.333	85.482	70.165	74.684
L	TOTAL DIRECT COST	$/KWE	238.509	251.032	278.359	225.572	239.283	265.470	222.145	236.270
T	INDIRECT COSTS	$/KWE	39.339	41.453	46.446	35.554	33.930	43.596	35.784	38.089
	PROF & OWNER COSTS	$/KWE	19.001	20.083	22.269	18.046	19.143	21.238	17.772	18.902
B	CONTINGENCY COST	$/KWE	19.040	19.562	21.047	18.040	19.582	20.117	17.772	18.454
R	ESCALATION COST	$/KWE	64.530	64.981	68.275	61.103	6[illegible].015	65.185	60.168	61.239
E	INT DURING CONSTRUCTION	$/KWE	74.299	74.329	77.411	70.375	71.037	74.026	69.307	70.091
A	TOTAL CAPITALIZATION	$/KWE	454.758	471.439	513.737	429.690	449.090	489.531	422.947	443.044
K	COST OF ELEC-CAPITAL	MILLS/KWE	14.375	14.903	16.240	13.583	14.197	15.478	13.370	14.006
D	COST OF ELEC-FUEL	MILLS/KWE	7.798	7.785	7.744	7.733	7.715	7.664	7.726	7.709
O	COST OF ELEC-OP&MAIN	MILLS/KWE	1.801	1.896	2.032	1.782	1.875	2.006	1.780	1.872
W	TOTAL COST OF ELEC	MILLS/KWE	23.975	24.585	26.017	23.098	23.787	25.148	22.877	23.587
N	COE 0.5 CAP. FACTOR	MILLS/KWE	28.298	29.055	30.889	27.174	29.046	29.792	26.888	27.789
	COE 0.8 CAP. FACTOR	MILLS/KWE	21.279	21.791	22.972	20.552	21.126	22.246	20.370	20.961
	COE 1.2XCAP. COST	MILLS/KWE	26.350	27.566	29.265	25.815	26.627	28.244	25.551	26.388
	COE 1.2XFUEL COST	MILLS/KWE	25.535	26.142	27.566	24.645	25.331	26.681	24.422	25.129
	COE (CONTINGENCY=0)	MILLS/KWE	23.103	23.707	25.338	22.277	22.949	24.26[illegible]	22.067	22.758
	COE (ESCALATION=0)	MILLS/KWE	21.595	22.203	23.535	20.844	21.512	72.775	20.657	21.341

	PARAMETRIC POINT		9	10	11	12	13	14	15	16
	TOTAL CAPITAL COST	M$	208.36	293.42	247.30	205.13	319.66	266.12	217.77	309.52
P	STEAM TURB-GEN-FEED STRING	M$	10.140	18.339	14.302	10.140	18.339	14.302	10.140	18.339
L	GAS TURBINE GENERATOR	M$	12.700	14.700	14.500	14.200	11.900	11.700	11.700	13.300
A	FLUIDIZED BED BOILER	M$	15.194	23.597	20.264	18.016	32.323	26.602	22.418	27.715
N	STACK GAS COOLER	M$	3.800	3.600	3.500	3.500	4.200	4.100	4.000	4.300
T										
R	TOT MAJOR COMPONENT COST	M$	45.834	60.236	52.555	45.856	65.762	56.704	48.258	63.654
E	TOT MAJOR COMPONENT COST	$/KWE	106.351	85.643	93.548	108.730	94.639	100.096	112.334	88.178
S	BALANCE OF PLANT COST	$/KWE	72.321	66.032	68.951	73.020	66.149	68.911	72.627	65.364
U	SITE LABOR	$/KWE	83.707	68.095	73.432	83.108	76.679	80.877	89.461	71.296
L	TOTAL DIRECT COST	$/KWE	262.379	219.770	235.930	264.858	237.462	249.883	274.422	224.838
T	INDIRECT COSTS	$/KWE	42.690	34.728	37.450	42.385	39.106	41.247	45.625	36.361
	PROF & OWNER COSTS	$/KWE	23.993	17.582	19.874	21.189	19.997	19.991	21.954	17.987
B	CONTINGENCY COST	$/KWE	19.889	17.564	18.401	20.032	18.984	19.506	20.795	18.019
R	ESCALATION COST	$/KWE	64.393	59.276	60.871	64.597	64.409	64.884	67.487	61.124
E	INT DURING CONSTRUCTION	$/KWE	73.132	68.260	69.644	73.322	74.177	74.251	76.640	70.441
A	TOTAL CAPITALIZATION	$/KWE	493.474	417.180	441.171	486.389	453.135	469.762	506.924	428.770
K	COST OF ELEC-CAPITAL	MILLS/KWE	15.284	13.188	13.946	15.376	14.325	14.850	16.025	13.554
D	COST OF ELEC-FUEL	MILLS/KWE	7.653	7.793	7.789	7.781	7.741	7.716	7.653	7.649
O	COST OF ELEC-OP&MAIN	MILLS/KWE	2.004	1.793	1.892	2.036	1.785	1.877	2.005	1.760
W	TOTAL COST OF ELEC	MILLS/KWE	24.950	22.764	23.527	25.193	23.851	24.443	25.683	22.963
N	COE 0.5 CAP. FACTOR	MILLS/KWE	29.536	26.721	27.811	29.806	28.148	28.898	30.491	27.030
	COE 0.8 CAP. FACTOR	MILLS/KWE	22.085	20.292	21.012	22.310	21.165	21.658	22.579	20.427
	COE 1.2XCAP. COST	MILLS/KWE	28.007	25.402	26.416	28.268	26.716	27.413	28.888	25.674
	COE 1.2XFUEL COST	MILLS/KWE	26.483	24.321	25.185	26.749	25.399	25.386	27.214	24.493
	COE (CONTINGENCY=0)	MILLS/KWE	24.072	21.965	22.801	24.309	22.996	23.566	24.765	22.142
	COE (ESCALATION=0)	MILLS/KWE	22.605	20.578	21.335	22.842	21.475	22.063	23.226	20.707

Table 12.31 Continued -

FLUIDIZED BED BOILER ADVANCED STEAM SYS   SUMMARY PLANT RESULTS

PLANT RESULT BREAKDOWN

PARAMETRIC POINT		17	18	19	20	21	22	23	24
TOTAL CAPITAL COST	,M$	253.13	214.28	302.91	254.92	208.40	297.67	251.64	208.87
STEAM TURB-GEN-FEED STRING	,M$	14.302	10.140	18.339	14.302	10.140	18.339	14.302	10.140
GAS TURBINE GENERATOR	,M$	13.100	12.900	13.700	13.500	13.300	15.700	15.300	15.100
FLUIDIZED BED BOILER	,M$	23.137	20.181	25.768	21.694	18.135	23.447	20.099	17.785
STACK GAS COOLER	,M$	4.000	4.000	4.000	3.900	3.900	3.800	3.700	3.700
TOT MAJOR COMPONENT COST	,M$	54.539	47.221	61.807	53.396	45.475	61.296	53.401	46.725
TOT MAJOR COMPONENT COST	,$/KWE	93.782	106.602	85.467	91.724	102.593	85.040	92.208	106.584
BALANCE OF PLANT COST	,$/KWE	67.965	71.213	65.187	67.784	71.221	65.205	67.875	71.495
SITE LABOR	,$/KWE	75.388	84.051	69.170	73.694	80.997	67.081	72.014	80.881
TOTAL DIRECT COST	,$/KWE	237.136	261.865	219.824	233.201	254.811	217.326	232.157	258.960
INDIRECT COSTS	,$/KWE	38.440	42.866	35.277	37.584	41.308	34.211	36.727	41.249
PROF & OWNER COSTS	,$/KWE	19.971	20.949	17.586	18.656	20.385	17.386	18.573	20.717
CONTINGENCY COST	,$/KWE	18.562	19.907	17.620	18.256	19.372	17.414	18.163	19.665
ESCALATION COST	,$/KWE	61.753	64.659	59.726	60.696	62.850	58.871	60.220	63.600
INT DURING CONSTRUCTION	,$/KWE	70.721	73.488	68.834	69.512	71.433	67.841	68.956	72.265
TOTAL CAPITALIZATION	,$/KWE	445.591	493.735	413.867	437.904	470.159	413.050	434.795	476.456
COST OF ELEC-CAPITAL	,MILLS/KWE	14.086	15.292	13.241	13.843	14.863	13.057	13.745	15.062
COST OF ELEC-FUEL	,MILLS/KWE	7.614	7.537	7.651	7.620	7.548	7.682	7.666	7.623
COST OF ELEC-OP&MAIN	,MILLS/KWE	1.846	1.968	1.759	1.847	1.969	1.766	1.857	1.987
TOTAL COST OF ELEC	,MILLS/KWE	23.546	24.797	22.651	23.310	24.380	22.505	23.268	24.672
COE 0.5 CAP. FACTOR	,MILLS/KWE	27.772	29.384	26.624	27.463	28.839	26.423	27.392	29.191
COE 0.8 CAP. FACTOR	,MILLS/KWE	20.905	21.929	20.168	20.715	21.593	20.057	20.691	21.848
COE 1.2XCAP. COST	,MILLS/KWE	26.364	27.855	25.299	26.079	27.353	25.117	26.017	27.684
COE 1.2XFUEL COST	,MILLS/KWE	25.069	26.334	24.181	24.834	25.890	24.042	24.802	26.197
COE (CONTINGENCY=0)	,MILLS/KWE	22.711	23.916	21.848	22.489	23.523	21.711	22.451	23.802
COE (ESCALATION=0)	,MILLS/KWE	21.280	22.441	20.447	21.083	22.090	20.333	21.059	22.355

PLANT RESULT BREAKDOWN

PARAMETRIC POINT		25	26	27	28	29	30	31	32
TOTAL CAPITAL COST	,M$	323.07	268.10	220.73	311.64	251.83	217.28	309.04	261.09
STEAM TURB-GEN-FEED STRING	,M$	18.339	14.302	10.140	18.339	14.302	10.140	18.339	14.302
GAS TURBINE GENERATOR	,M$	12.500	12.500	12.200	13.800	13.600	13.500	14.300	14.200
FLUIDIZED BED BOILER	,M$	32.602	26.377	22.670	27.744	23.055	20.135	26.615	22.455
STACK GAS COOLER	,M$	4.300	4.200	4.000	4.100	4.100	4.000	4.000	4.000
TOT MAJOR COMPONENT COST	,M$	67.741	57.179	49.010	63.983	55.057	47.775	63.254	54.957
TOT MAJOR COMPONENT COST	,$/KWE	94.801	99.370	111.815	87.103	92.699	104.965	85.672	92.070
BALANCE OF PLANT COST	,$/KWE	65.698	68.334	71.825	64.779	67.210	70.393	64.495	66.893
SITE LABOR	,$/KWE	76.292	79.955	88.668	70.359	74.400	82.675	69.134	73.554
TOTAL DIRECT COST	,$/KWE	236.792	247.659	272.308	222.240	234.308	258.033	219.302	232.517
INDIRECT COSTS	,$/KWE	38.939	40.777	45.221	35.883	37.944	42.164	35.258	37.512
PROF & OWNER COSTS	,$/KWE	18.943	19.813	21.785	17.779	18.745	20.643	17.544	18.601
CONTINGENCY COST	,$/KWE	19.956	19.364	20.678	17.944	18.382	19.671	17.618	18.251
ESCALATION COST	,$/KWE	64.371	64.483	67.220	60.613	61.260	64.037	59.841	60.823
INT DURING CONSTRUCTION	,$/KWE	74.151	73.824	76.377	69.888	70.197	72.833	69.008	59.706
TOTAL CAPITALIZATION	,$/KWE	452.133	465.920	503.588	424.248	440.836	477.382	418.571	437.411
COST OF ELEC-CAPITAL	,MILLS/KWE	14.293	14.729	15.920	13.411	13.936	15.091	13.232	13.828
COST OF ELEC-FUEL	,MILLS/KWE	7.686	7.650	7.569	7.578	7.528	7.428	7.566	7.519
COST OF ELEC-OP&MAIN	,MILLS/KWE	1.770	1.858	1.979	1.740	1.822	1.934	1.736	1.817
TOTAL COST OF ELEC	,MILLS/KWE	23.749	24.236	25.468	22.729	23.285	24.453	22.534	23.164
COE 0.5 CAP. FACTOR	,MILLS/KWE	29.037	28.655	30.244	26.752	27.466	28.981	26.503	27.312
COE 0.8 CAP. FACTOR	,MILLS/KWE	21.069	21.474	22.483	20.214	20.672	21.624	20.053	20.572
COE 1.2XCAP. COST	,MILLS/KWE	26.608	27.192	28.652	25.411	25.072	27.472	25.180	25.930
COE 1.2XFUEL COST	,MILLS/KWE	25.286	25.766	26.981	24.245	24.791	25.939	24.047	24.668
COE (CONTINGENCY=0)	,MILLS/KWE	22.885	23.365	24.5[illegible]3	21.914	22.457	23.582	21.729	22.342
COE (ESCALATION=0)	,MILLS/KWE	21.374	21.871	23.019	20.491	21.036	22.118	20.324	20.931

Table 12.31 Continued -
FLUIDIZED BED BOILER ADVANCED STEAM SYS SUMMARY PLANT RESULTS

	PARAMETRIC POINT		33	34	35	36	37	38	39	40
	TOTAL CAPITAL COST	,M$	217.01	304.35	258.64	213.01	308.16	258.53	213.28	311.93
P	STEAM TURB-GEN-FEED STRING	,M$	10.140	18.339	14.302	10.140	20.830	16.295	11.635	21.328
L	GAS TURBINE GENERATOR	,M$	14.000	16.400	16.100	15.900	13.100	12.900	12.700	13.100
A	FLUIDIZED BED BOILER	,M$	19.782	24.283	20.998	17.919	25.952	21.897	19.194	25.952
N	STACK GAS COOLER	,M$	4.000	3.900	3.800	3.800	3.800	3.800	3.800	3.800
T										
R	TOT MAJOR COMPONENT COST	,M$	47.922	62.922	55.200	47.759	63.682	54.892	47.329	64.180
E	TOT MAJOR COMPONENT COST	,$/KWE	104.739	85.454	92.936	105.256	87.663	93.804	107.022	96.446
S	BALANCE OF PLANT COST	,$/KWE	70.030	64.629	67.110	70.184	65.702	68.132	72.028	80.127
U	SITE LABOR	,$/KWE	81.754	57.055	71.397	79.259	69.439	73.573	82.582	72.858
L	TOTAL DIRECT COST	,$/KWE	256.582	217.139	231.993	254.700	222.805	235.509	261.633	249.432
T	INDIRECT COSTS	,$/KWE	41.730	34.198	36.713	40.422	35.414	37.522	42.117	37.158
	PROF & OWNER COSTS	,$/KWE	20.577	17.371	18.559	20.376	17.824	18.841	20.931	19.955
B	CONTINGENCY COST	,$/KWE	19.570	17.439	18.201	19.411	17.869	18.448	19.887	19.837
R	ESCALATION COST	,$/KWE	63.693	59.073	60.491	62.947	60.527	61.280	64.458	66.216
E	INT DURING CONSTRUCTION	,$/KWE	72.452	58.116	69.317	71.588	69.768	70.192	73.257	76.152
A	TOTAL CAPITALIZATION	,$/KWE	474.523	413.336	435.275	469.443	424.207	441.793	482.283	468.799
K	COST OF ELEC-CAPITAL	,MILLS/KWE	15.031	13.066	13.760	14.840	13.410	13.966	15.246	14.818
D	COST OF ELEC-FUEL	,MILLS/KWE	7.424	7.596	7.561	7.487	7.552	7.506	7.467	8.244
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.931	1.742	1.826	1.945	1.742	1.826	1.958	1.824
W	TOTAL COST OF ELEC	,MILLS/KWE	24.356	22.404	23.148	24.272	22.704	23.298	24.671	24.886
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	28.856	25.324	27.276	28.724	25.727	27.488	29.245	29.332
	COE 0.8 CAP. FACTOR	,MILLS/KWE	21.543	19.954	20.568	21.490	20.190	20.680	21.813	22.108
	COE 1.2XCAP. COST	,MILLS/KWE	27.355	25.017	25.900	27.240	25.386	26.092	27.720	27.850
	COE 1.2XFUEL COST	,MILLS/KWE	25.841	23.923	24.660	25.770	24.214	24.800	26.165	26.535
	COE (CONTINGENCY=0)	,MILLS/KWE	23.499	21.608	22.328	23.412	21.889	22.468	23.791	23.986
	COE (ESCALATION=0)	,MILLS/KWE	22.033	20.223	20.927	21.977	20.470	21.049	22.322	22.447

	PARAMETRIC POINT		41	42	43	44	45	46	47	48
	TOTAL CAPITAL COST	,M$	263.71	214.10	408.36	335.32	256.94	484.29	457.87	434.83
P	STEAM TURB-GEN-FEED STRING	,M$	16.544	11.635	53.295	46.314	33.160	60.665	83.807	106.651
L	GAS TURBINE GENERATOR	,M$	12.900	12.700	13.100	12.900	12.700	13.100	12.900	12.700
A	FLUIDIZED BED BOILER	,M$	21.897	19.194	27.727	23.242	20.120	32.208	26.643	22.427
N	STACK GAS COOLER	,M$	3.800	3.800	4.000	3.900	3.900	4.100	4.000	4.000
T										
R	TOT MAJOR COMPONENT COST	,M$	55.141	47.329	104.122	86.356	69.880	110.073	127.350	145.778
E	TOT MAJOR COMPONENT COST	,$/KWE	103.245	117.324	134.021	139.123	149.920	133.826	194.218	297.513
S	BALANCE OF PLANT COST	,$/KWE	82.663	76.422	77.177	78.820	81.401	109.107	108.717	107.748
U	SITE LABOR	,$/KWE	77.579	87.432	70.645	75.233	84.270	73.379	81.417	96.867
L	TOTAL DIRECT COST	,$/KWE	263.497	271.178	281.843	293.175	315.591	316.312	384.352	502.127
T	INDIRECT COSTS	,$/KWE	39.566	44.590	36.029	38.369	42.978	37.423	41.523	49.402
	PROF & OWNER COSTS	,$/KWE	21.073	23.294	22.547	23.454	25.247	25.305	30.748	40.170
B	CONTINGENCY COST	,$/KWE	20.400	21.542	22.766	23.107	24.119	25.708	30.470	38.575
R	ESCALATION COST	,$/KWE	66.392	70.150	75.741	75.492	77.061	85.330	98.259	120.188
E	INT DURING CONSTRUCTION	,$/KWE	76.559	79.563	87.473	86.612	87.702	98.713	112.918	136.968
A	TOTAL CAPITALIZATION	,$/KWE	498.143	530.728	525.399	540.210	572.697	588.791	698.281	887.431
K	COST OF ELEC-CAPITAL	,MILLS/KWE	15.431	16.777	16.641	17.077	18.104	18.613	22.074	28.054
D	COST OF ELEC-FUEL	,MILLS/KWE	8.223	8.186	7.099	7.105	7.106	6.782	6.794	6.807
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	1.923	2.066	1.638	1.731	1.868	1.561	1.653	1.790
W	TOTAL COST OF ELEC	,MILLS/KWE	25.577	27.030	25.377	25.915	27.078	26.956	30.521	36.651
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	30.207	32.063	30.369	31.038	32.510	32.540	37.143	45.067
	COE 0.8 CAP. FACTOR	,MILLS/KWE	22.634	23.884	22.257	22.713	23.684	23.466	26.382	31.391
	COE 1.2XCAP. COST	,MILLS/KWE	28.664	30.385	28.705	29.330	30.699	30.679	34.936	42.262
	COE 1.2XFUEL COST	,MILLS/KWE	27.222	28.667	25.797	27.336	29.500	28.312	31.880	38.013
	COE (CONTINGENCY=0)	,MILLS/KWE	24.661	26.063	24.334	24.871	26.008	25.774	29.140	34.934
	COE (ESCALATION=0)	,MILLS/KWE	23.124	24.478	22.576	23.140	24.267	23.796	26.904	32.261

Table 12.31 Continued -
FLUIDIZED BED BOILER ADVANCED STEAM SYS   SUMMARY PLANT RESULTS

	PARAMETRIC POINT		49	50	51	52	53	54	55	56
	TOTAL CAPITAL COST	,M$	287.57	238.02	201.66	297.39	251.57	209.51	.00	.00
P	STEAM TURB-GEN-FEED STRING	,M$	18.339	14.302	10.140	18.339	14.302	10.140	.000	.000
L	GAS TURBINE GENERATOR	,M$	13.100	13.000	12.700	13.100	13.000	12.700	.000	.000
A	FLUIDIZED BED BOILER	,M$	27.092	23.037	20.334	28.652	24.597	21.894	.000	.000
N	STACK GAS COOLER	,M$	3.800	3.800	3.800	3.800	3.800	3.800	.000	.000
T										
R	TOT MAJOR COMPONENT COST	,M$	62.331	54.139	46.974	63.891	55.699	48.534	.000	.000
E	TOT MAJOR COMPONENT COST	,$/KWE	87.730	94.968	108.935	90.090	97.882	112.756	.000	.000
S	BALANCE OF PLANT COST	,$/KWE	58.935	61.571	65.098	61.426	64.132	67.738	.000	.000
U	SITE LABOR	,$/KWE	66.357	67.426	80.134	68.987	73.984	83.847	.000	.000
L	TOTAL DIRECT COST	,$/KWE	213.023	223.965	254.167	220.502	235.998	264.341	.000	.000
T	INDIRECT COSTS	,$/KWE	33.842	34.388	40.868	35.183	37.732	42.762	.000	.000
	PROF & OWNER COSTS	,$/KWE	17.042	17.917	20.333	17.640	19.380	21.147	.000	.000
B	CONTINGENCY COST	,$/KWE	17.042	17.493	19.267	17.640	18.433	20.038	.000	.000
R	ESCALATION COST	,$/KWE	57.601	57.712	62.287	59.654	61.107	64.828	.000	.000
E	INT DURING CONSTRUCTION	,$/KWE	66.349	66.055	70.740	68.715	69.940	73.626	.000	.000
A	TOTAL CAPITALIZATION	,$/KWE	404.938	417.530	467.662	419.335	442.089	486.742	.000	.000
K	COST OF ELEC-CAPITAL	,MILLS/KWE	12.800	13.199	14.784	13.256	13.975	15.387	.000	.000
D	COST OF ELEC-FUEL	,MILLS/KWE	7.440	7.423	7.378	7.608	7.590	7.545	.000	.000
O	COST OF ELEC-OP&MAIN	,MILLS/KWE	.879	.973	1.111	.914	1.009	1.146	.000	.000
W	TOTAL COST OF ELEC	,MILLS/KWE	21.118	21.595	23.273	21.778	22.574	24.078	.000	.000
N	COE 0.5 CAP. FACTOR	,MILLS/KWE	24.958	25.555	27.708	25.755	26.767	28.694	.000	.000
	COE 0.8 CAP. FACTOR	,MILLS/KWE	18.718	19.120	20.501	19.292	19.954	21.193	.000	.000
	COE 1.2XCAP. COST	,MILLS/KWE	23.678	24.235	26.229	24.429	25.370	27.155	.000	.000
	COE 1.2XFUEL COST	,MILLS/KWE	22.605	23.080	24.748	23.299	24.093	25.587	.000	.000
	COE (CONTINGENCY=0)	,MILLS/KWE	20.342	20.809	22.421	20.974	21.746	23.192	.000	.000
	COE (ESCALATION=0)	,MILLS/KWE	18.933	19.478	21.004	19.577	20.333	21.717	.000	.000

The major component summations in Table 12.30 include the material prices from the following subaccounts:

	Subaccount
• Steam turbine-generator and feed string	11.5, 11.6, 13.1
• Gas turbine-generator	11.1, 11.2, 11.3, 11.4
• Pressurized boiler	10.1
• Stack-gas cooler	13.2

The major component summations in Table 12.31 are similar to those in Table 12.30 except that the title "Fluidized Bed Boiler" replaces the title "Pressurized Boiler."

In addition, the natural resources requirements for each parametric point were calculated and printed by the computer. These results are shown in Tables 12.32 through 12.34.

12.7 Conclusions and Recommendations

Increasing either throttle or reheat steam temperature in 111°K (200°F) increments from 811 to 1033°K (1000 to 1400°F) results in an increase in electrical energy cost because the increase due to higher capital cost substantially exceeds the decrease due to lower fuel costs (higher cycle efficiency).

The system resulting in the lowest energy cost is the pressurized fluidized bed boiler system with 811°K (1000°F) steam and 1255°K (1800°F) gas turbine inlet temperature.

It is recommended that the pressurized fluidized bed boiler system be investigated in greater detail in Task II.

Any future study of this type may well benefit by first defining the most promising areas for investigation by looking at the energy availability and internal reversibilities of various cycles. This would allow the major portion of the effort to be concentrated where it belongs rather than diluting the effort by covering too large a number of points. An example of such an approach is given in Appendix A 12.7.6.

Table 12.32 - ADVANCED STEAM CYCLE WITH ATM BOILER NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
COAL, LB/KW-HR	.85723	.88039	.95306	.86483	.88837	.89441	.81015	.83082
SORBANT OR SEED,LB/KW-HR	.12438	.12933	.13911	.12601	.12951	.47323	.11787	.12095
TOTAL WATER, GAL/KW-HR	.966	1.013	.099	1.000	1.048	1.117	.885	.928
COOLING WATER	.875	.921	.000	.909	.955	.952	.800	.841
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01034	.01034	.01049	.01035	.01035	.01032	.01032	.01032
WASTE HANDLING SLURRY	.0293	.0301	.0326	.0295	.0303	.1015	.0276	.0283
SCRUBBER WASTE WATER	.05029	.05158	.05602	.05074	.05215	.05366	.04746	.04870
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	101.75	94.96	190.04	106.04	99.15	142.36	99.78	92.78
MAIN PLANT	28.87	28.87	29.29	28.89	28.90	28.80	28.82	28.82
DISPOSAL LAND	33.72	34.65	37.54	34.03	34.96	78.39	31.85	32.67
LAND FOR ACCESS RR	39.17	31.34	123.21	43.12	35.29	35.17	39.11	31.29

PARAMETRIC POINT	9	10	11	12	13	14	15	16
COAL, LB/KW-HR	.93542	.77028	.79359	.79212	.82993	.82229	.87256	.89489
SORBANT OR SEED,LB/KW-HR	.44202	.11193	.11466	.41911	.12065	.11967	.12716	.13049
TOTAL WATER, GAL/KW-HR	.993	.804	.843	.905	.923	.910	1.015	1.026
COOLING WATER	.838	.722	.760	.757	.836	.823	.923	.932
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01029	.01030	.01030	.01027	.01033	.01033	.01035	.01035
WASTE HANDLING SLURRY	.0949	.0262	.0269	.0899	.0283	.0280	.0298	.0306
SCRUBBER WASTE WATER	.05013	.04507	.04617	.04753	.04858	.04819	.05120	.05254
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	133.14	94.16	87.08	125.35	100.57	100.29	106.37	95.46
MAIN PLANT	28.73	28.77	28.77	28.69	28.84	28.83	28.90	28.88
DISPOSAL LAND	73.22	30.26	30.99	69.43	32.59	32.33	34.33	35.22
LAND FOR ACCESS RR	31.19	35.13	27.32	27.24	39.13	39.12	43.13	31.35

PARAMETRIC POINT	17	18	19	20	21	22	23	24
COAL, LB/KW-HR	.83880	.86110	.89867	.91200	.98963	.83482	.85621	.86145
SORBANT OR SEED,LB/KW-HR	.12213	.12545	.12956	.13303	.14455	.12154	.12473	.45579
TOTAL WATER, GAL/KW-HR	.893	.990	1.052	1.100	.103	.939	.984	1.051
COOLING WATER	.805	.900	.959	1.005	.000	.851	.894	.891
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01033	.01034	.01035	.01035	.01052	.01033	.01034	.01030
WASTE HANDLING SLURRY	.0286	.0294	.0304	.0312	.0339	.0285	.0292	.0978
SCRUBBER WASTE WATER	.04918	.05052	.05217	.05357	.05821	.04894	.05023	.05169
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	100.90	94.06	107.05	100.15	199.84	100.82	93.85	135.47
MAIN PLANT	28.84	28.86	28.92	28.92	29.36	28.85	28.85	28.76
DISPOSAL LAND	32.93	33.88	34.98	35.91	38.99	32.93	33.69	75.51
LAND FOR ACCESS RR	39.13	31.32	43.16	35.32	131.49	39.14	31.32	31.21

PARAMETRIC POINT	25	26	27	28	29	30	31	32
COAL, LB/KW-HR	.79571	.81578	.82104	.95391	.93937	.81449	.81867	.83179
SORBANT OR SEED,LB/KW-HR	.11507	.11826	.43441	.12587	.12222	.11851	.43316	.12109
TOTAL WATER, GAL/KW-HR	.860	.902	.966	.999	.949	.897	.961	.934
COOLING WATER	.776	.816	.814	.909	.860	.811	.809	.847
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01032	.01032	.01028	.01035	.01034	.01033	.01029	.01033
WASTE HANDLING SLURRY	.0272	.0278	.0932	.0295	.0286	.0278	.0929	.0289
SCRUBBER WASTE WATER	.04666	.04786	.04926	.05069	.04922	.04772	.04912	.04876
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	95.28	88.27	127.94	106.00	101.02	99.96	139.48	100.70
MAIN PLANT	28.80	28.80	28.71	28.89	28.85	28.83	28.73	28.85
DISPOSAL LAND	31.31	32.11	71.96	33.99	33.01	32.02	71.76	32.71
LAND FOR ACCESS RR	35.17	27.35	27.27	43.12	39.15	39.11	38.99	39.14

Table 12.32 ADVANCED STEAM CYCLE WITH ATM BOILER NATURAL RESOURCE REQUIREMENTS
Continued

PARAMETRIC POINT	33	34	35	36	37	38	39	40
COAL, LB/KW-HR	.83640	1.09118	1.47671	.91863	1.09118	1.47671	.90602	.92941
SORBANT OR SEED, LB/KW-HR	.44254	.03311	.03900	.48605	.03311	.03900	.13214	.13562
TOTAL WATER, GAL/KW-HR	.999	1.073	1.080	1.171	1.073	1.080	1.086	1.136
COOLING WATER	.844	1.030	1.003	1.001	1.000	1.003	.992	1.039
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01030	.01031	.01034	.01032	.01031	.01034	.01037	.01037
WASTE HANDLING SLURRY	.0949	.0102	.0119	.1043	.0102	.0119	.0316	.0318
SCRUBBER WASTE WATER	.05018	.05236	.05489	.05512	.05285	.05488	.05321	.05461
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	141.07	83.80	86.64	144.53	83.80	86.64	111.74	100.89
MAIN PLANT	28.75	28.78	28.86	28.82	28.78	28.86	28.95	28.94
DISPOSAL LAND	73.31	19.98	22.54	90.52	19.88	22.54	35.67	36.60
LAND FOR ACCESS RR	39.01	35.14	35.24	35.20	35.14	35.24	47.13	35.34

PARAMETRIC POINT	41	42	43	44	45	46	47	48
COAL, LB/KW-HR	.93545	1.00820	.95535	.97592	.98259	.94883	.84992	.85499
SORBANT OR SEED, LB/KW-HR	.49548	.14732	.12460	.12779	.46697	.13848	.12379	.45238
TOTAL WATER, GAL/KW-HR	1.208	.134	.981	1.025	1.095	.099	.972	1.039
COOLING WATER	1.035	.000	.892	.934	.931	.000	.883	.880
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01033	.01053	.01035	.01034	.01031	.01049	.01034	.01031
WASTE HANDLING SLURRY	.1063	.0345	.0292	.0299	.1002	.0324	.0290	.0970
SCRUBBER WASTE WATER	.05619	.05932	.05017	.05146	.05295	.05576	.04985	.05130
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	146.13	204.76	105.64	94.72	137.37	189.88	101.47	142.74
MAIN PLANT	28.84	29.40	28.88	28.87	28.78	29.29	28.87	28.77
DISPOSAL LAND	82.08	39.73	33.65	34.50	77.36	37.37	33.43	74.94
LAND FOR ACCESS RR	35.22	135.63	43.11	31.34	31.24	123.21	39.17	39.04

PARAMETRIC POINT	49	50	51	52	53	54	55	56
COAL, LB/KW-HR	.87774	.83284	.85435	.92083	.85826	.88477	.80347	.82803
SORBANT OR SEED, LB/KW-HR	.12793	.12124	.12445	.13431	.12503	.12898	.11687	.12053
TOTAL WATER, GAL/KW-HR	1.028	.936	.981	.095	.987	1.042	.872	.924
COOLING WATER	.935	.849	.891	.000	.897	.950	.788	.836
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01035	.01033	.01033	.01049	.01034	.01035	.01032	.01032
WASTE HANDLING SLURRY	.0300	.0284	.0292	.0315	.0293	.0302	.0274	.0282
SCRUBBER WASTE WATER	.05152	.04832	.05011	.05409	.05035	.05194	.04706	.04854
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	106.59	100.74	93.78	184.57	95.42	87.79	88.75	81.05
MAIN PLANT	28.91	28.85	28.85	29.25	20.30	20.30	20.25	20.25
DISPOSAL LAND	34.54	32.75	33.61	36.25	33.77	34.92	31.59	32.56
LAND FOR ACCESS RR	43.14	39.14	31.32	119.07	41.36	32.66	36.92	28.24

PARAMETRIC POINT	57	58	59	60	61	62	63	64
COAL, LB/KW-HR	.75546	.78599	.85611	.99182	.83317	.85900	.88341	.90751
SORBANT OR SEED, LB/KW-HR	.11121	.11442	.12620	.13003	.12129	.12499	.12877	.13237
TOTAL WATER, GAL/KW-HR	.795	.841	1.003	1.058	.934	.995	1.040	.918
COOLING WATER	.714	.758	.912	.964	.847	.896	.947	.824
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01030	.01030	.01035	.01035	.01033	.01033	.01036	.01034
WASTE HANDLING SLURRY	.0261	.0268	.0296	.0305	.0284	.0293	.0302	.0310
SCRUBBER WASTE WATER	.04478	.04608	.05002	.05236	.04884	.05033	.05186	.05330
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	82.79	77.16	95.75	88.08	92.18	84.48	98.68	84.28
MAIN PLANT	20.21	20.22	20.30	20.31	20.27	20.28	20.32	20.28
DISPOSAL LAND	30.07	30.93	34.08	35.10	32.77	33.76	34.77	35.73
LAND FOR ACCESS RR	32.51	26.02	41.37	32.67	39.14	30.45	43.59	28.27

Table 12.32 ADVANCED STEAM CYCLE WITH ATM BOILER NATURAL RESOURCE REQUIREMENTS

Continued

PARAMETRIC POINT	55	56	57	58	69	70	71	72
COAL, LB/KW-HR	.83049	.85487	.79331	.81639	.90056	.92584	.85061	.87504
SORBANT OR SEED,LB/KW-HR	.12090	.12453	.11535	.11380	.13133	.13509	.12389	.12753
TOTAL WATER, GAL/KW-HR	.930	.982	.854	.903	1.076	1.128	.972	1.022
COOLING WATER	.993	.932	.771	.817	.982	1.031	.883	.931
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.01033	.01033	.01031	.01032	.01036	.01037	.01034	.01034
WASTE HANDLING SLURRY	.0283	.0292	.0270	.0278	.0308	.0316	.0290	.0299
SCRUBBER WASTE WATER	.04358	.05014	.04645	.04794	.05288	.05440	.04989	.05135
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	32.07	94.35	85.14	80.55	99.40	91.70	92.91	87.38
MAIN PLANT	20.27	20.28	20.24	20.24	20.33	20.34	20.29	20.29
DISPOSAL LAND	32.66	33.63	31.19	32.10	35.45	36.46	33.46	34.43
LAND FOR ACCESS RR	39.14	30.45	34.73	28.22	43.62	34.90	39.17	32.65

PARAMETRIC POINT	73	74	75	76	77	78	79	80
COAL, LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
SORBANT OR SEED,LB/KW-HR	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL WATER, GAL/KW-HR	.000	.000	.000	.000	.000	.000	.000	.000
COOLING WATER	.000	.000	.000	.000	.000	.000	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
WASTE HANDLING SLURRY	.0000	.0000	.0000	.0000	.0000	.0000	.0000	.0000
SCRUBBER WASTE WATER	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	.00	.00	.00	.00	.00	.00	.00	.00
MAIN PLANT	.00	.00	.00	.00	.00	.00	.00	.00
DISPOSAL LAND	.00	.00	.00	.00	.00	.00	.00	.00
LAND FOR ACCESS RR	.00	.00	.00	.00	.00	.00	.00	.00

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Table 12.33 - PRESSURIZED BOILER ADVANCED STEAM SYSTEM NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
COAL, LB/KW-HR	.99901	.88533	.87862	.89038	.88849	.98307	.90433	.90295
SORBANT OR SEED, LB/KW-HR	.47037	.46896	.46488	.47110	.47010	.46723	.47848	.47775
TOTAL WATER, GAL/KW-HR	.932	.956	.934	.979	.963	.935	.991	.976
COOLING WATER	.825	.810	.779	.822	.807	.780	.832	.817
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00841	.00820	.00785	.00839	.00818	.00784	.00851	.00832
WASTE HANDLING SLURRY	.0974	.0971	.0962	.0975	.0973	.0967	.0990	.0989
SCRUBBER WASTE WATER	.05111	.05096	.05052	.05116	.05106	.05074	.05191	.05183
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	129.72	129.59	129.72	127.03	129.67	129.94	131.37	131.58
MAIN PLANT	21.93	23.93	23.56	21.91	23.80	26.49	22.03	24.02
DISPOSAL LAND	77.79	77.55	76.86	77.91	77.74	77.27	79.12	79.00
LAND FOR ACCESS RR	30.00	28.20	29.29	27.22	28.13	26.19	30.21	28.56
PARAMETRIC POINT	9	10	11	12	13	14	15	16
COAL, LB/KW-HR	.90229	.93112	.93454	.93727	.84451	.93851	.82917	.84631
SORBANT OR SEED, LB/KW-HR	.47740	.49256	.49447	.49591	.44683	.44365	.43871	.44778
TOTAL WATER, GAL/KW-HR	.955	1.023	1.015	.999	.900	.878	.845	.933
COOLING WATER	.797	.859	.851	.834	.752	.731	.700	.784
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00802	.00833	.00867	.00841	.00771	.00744	.00794	.00765
WASTE HANDLING SLURRY	.0988	.1020	.1024	.1027	.0925	.0918	.0908	.0927
SCRUBBER WASTE WATER	.05179	.05337	.05356	.05372	.04856	.04821	.04767	.04863
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	132.41	135.39	135.75	137.25	120.36	122.10	121.31	122.56
MAIN PLANT	26.80	22.45	24.50	27.47	21.02	22.70	24.99	20.87
DISPOSAL LAND	79.94	81.46	81.76	82.00	73.99	73.37	72.55	74.05
LAND FOR ACCESS RR	26.67	31.18	29.49	27.78	25.45	26.03	23.77	27.64
PARAMETRIC POINT	17	18	19	20	21	22	23	24
COAL, LB/KW-HR	.83330	.82924	.85573	.84564	.83852	.87561	.87185	.86063
SORBANT OR SEED, LB/KW-HR	.44359	.43875	.45276	.44795	.44366	.46382	.46130	.45536
TOTAL WATER, GAL/KW-HR	.872	.839	.901	.873	.845	.822	.801	.865
COOLING WATER	.724	.693	.750	.724	.698	.768	.748	.714
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00737	.00697	.00763	.00737	.00698	.00783	.00758	.00719
WASTE HANDLING SLURRY	.0919	.0908	.0937	.0927	.0918	.0950	.0955	.0943
SCRUBBER WASTE WATER	.04818	.04765	.04912	.04859	.04813	.05024	.04997	.04932
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	121.68	120.92	122.86	122.15	121.63	125.41	124.96	124.47
MAIN PLANT	22.55	24.33	20.73	22.47	24.79	20.93	22.69	25.15
DISPOSAL LAND	73.36	72.56	74.87	74.07	73.36	76.69	76.28	75.30
LAND FOR ACCESS RR	25.75	23.93	27.28	25.60	23.47	27.79	26.00	24.02
PARAMETRIC POINT	25	26	27	28	29	30	31	32
COAL, LB/KW-HR	.80026	.79222	.77549	.80246	.79471	.78270	.81709	.80983
SORBANT OR SEED, LB/KW-HR	.42343	.41917	.41243	.42459	.42048	.41413	.43232	.42848
TOTAL WATER, GAL/KW-HR	.812	.787	.749	.802	.777	.739	.812	.787
COOLING WATER	.671	.648	.612	.661	.638	.603	.669	.646
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00538	.00659	.00615	.00677	.00648	.00505	.00686	.00657
WASTE HANDLING SLURRY	.0876	.0868	.0854	.0879	.0870	.0857	.0895	.0887
SCRUBBER WASTE WATER	.04539	.04552	.04479	.04605	.04551	.04492	.04683	.04641
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	112.72	113.92	117.34	112.29	113.33	112.00	113.72	114.92
MAIN PLANT	19.75	21.21	22.16	19.53	20.98	22.91	19.59	21.06
DISPOSAL LAND	70.02	69.12	69.70	70.21	69.53	68.48	71.49	70.85
LAND FOR ACCESS RR	22.95	23.29	20.97	22.55	22.87	20.61	22.65	23.01

Table 12.33 Continued

PRESSURIZED BOILER ADVANCED STEAM SYSTEM NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	33	34	35	36	37	38	39	40
COAL, LB/KW-HR	.79955	.85482	.85755	.84654	.83622	.82235	.81069	.89765
SORBANT OR SEED,LB/KW-HR	.42252	.45758	.41378	.44790	.44244	.43511	.42891	.47494
TOTAL WATER, GAL/KW-HR	.750	.863	.837	.798	.862	.851	.816	.157
COOLING WATER	.643	.711	.687	.651	.735	.706	.674	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00614	.00730	.00699	.00654	.00768	.00743	.00705	.00759
WASTE HANDLING SLURRY	.0975	.0947	.0939	.0927	.0915	.0901	.0888	.0983
SCRUBBER WASTE WATER	.04577	.04941	.04900	.04836	.04805	.04725	.04658	.05158
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	113.67	119.33	120.72	119.60	128.65	127.95	128.27	193.53
MAIN PLANT	23.03	20.09	21.64	23.73	20.72	22.30	24.50	21.70
DISPOSAL LAND	69.86	75.65	75.03	74.05	73.17	71.95	70.93	78.54
LAND FOR ACCESS RR	20.79	23.59	24.05	21.82	34.76	33.63	32.85	93.29

PARAMETRIC POINT	41	42	43	44	45	46	47	48
COAL, LB/KW-HR	.88818	.87795	.79165	.77711	.77246	.74867	.74545	.74215
SORBANT OR SEED,LB/KW-HR	.45993	.46452	.41357	.41117	.40871	.39612	.39442	.39267
TOTAL WATER, GAL/KW-HR	.156	.153	.794	.776	.750	.721	.705	.683
COOLING WATER	.000	.000	.656	.638	.614	.589	.573	.552
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00731	.00598	.00782	.00757	.00718	.00792	.00768	.00731
WASTE HANDLING SLURRY	.0973	.0902	.0856	.0851	.0846	.0820	.0816	.0813
SCRUBBER WASTE WATER	.05104	.05045	.04492	.04465	.04439	.04302	.04284	.04264
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	192.15	199.72	111.51	110.64	113.17	104.64	106.21	108.85
MAIN PLANT	23.44	25.79	19.89	21.49	23.74	19.27	20.86	23.07
DISPOSAL LAND	77.71	76.32	63.39	67.99	67.59	65.51	65.22	64.94
LAND FOR ACCESS RR	90.99	65.41	28.23	21.15	21.85	19.86	20.13	20.84

PARAMETRIC POINT	49	50	51	52	53	54	55	56
COAL, LB/KW-HR	1.01459	1.30573	.93475	1.34867	1.33682	1.32221	.00000	.00000
SORBANT OR SEED,LB/KW-HR	.11526	.11425	.11300	.12864	.12751	.12611	.00000	.00000
TOTAL WATER, GAL/KW-HR	.827	.803	.771	.831	.807	.774	.000	.000
COOLING WATER	.747	.724	.693	.748	.725	.694	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00764	.00737	.00697	.00765	.00738	.00698	.00000	.00000
WASTE HANDLING SLURRY	.0239	.0236	.0234	.0266	.0264	.0261	.0000	.0000
SCRUBBER WASTE WATER	.04835	.04792	.04740	.04826	.04783	.04731	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	75.05	77.15	76.87	78.28	80.35	80.04	.00	.00
MAIN PLANT	20.85	22.55	24.82	20.88	22.59	24.86	.00	.00
DISPOSAL LAND	29.10	28.84	28.53	32.25	31.97	31.62	.00	.00
LAND FOR ACCESS RR	25.10	25.75	23.52	25.15	25.80	23.56	.00	.00

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Table 12.34 - FLUIDIZED BED BOILER ADVANCED STEAM SYS NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	1	2	3	4	5	6	7	8
COAL, LB/KW-HR	.85042	.84903	.84451	.84328	.84138	.83575	.84260	.84069
SORBANT OR SEED,LB/KW-HR	.44995	.44922	.44683	.44518	.44518	.44220	.44582	.44481
TOTAL WATER, GAL/KW-HR	.973	.948	.903	.959	.933	.886	.956	.930
COOLING WATER	.922	.797	.754	.809	.783	.739	.806	.780
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00951	.00915	.00753	.00837	.00801	.00738	.00934	.00798
WASTE HANDLING SLURRY	.0931	.0930	.0925	.0924	.0922	.0915	.0923	.0921
SCRUBBER WASTE WATER	.04990	.04992	.04355	.04949	.04937	.04904	.04944	.04933
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	122.59	125.95	125.10	121.29	124.41	124.46	121.10	124.19
MAIN PLANT	19.39	22.14	26.21	19.19	21.90	25.88	19.15	21.85
DISPOSAL LAND	74.47	74.35	73.95	73.85	73.68	73.19	73.79	73.62
LAND FOR ACCESS RR	28.73	[illegible]	25.94	28.26	28.83	25.39	28.17	28.72

PARAMETRIC POINT	9	10	11	12	13	14	15	16
COAL, LB/KW-HR	.83563	.84978	.84934	.84854	.84417	.84143	.83463	.83419
SORBANT OR SEED,LB/KW-HR	.44213	.44909	.44939	.44896	.44665	.44520	.44160	.44137
TOTAL WATER, GAL/KW-HR	.884	.955	.942	.902	.961	.934	.886	.941
COOLING WATER	.736	.813	.791	.752	.811	.785	.738	.793
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00735	.00842	.00809	.00751	.00840	.00802	.00738	.00821
WASTE HANDLING SLURRY	.0915	.0930	.0930	.0929	.0925	.0922	.0914	.0914
SCRUBBER WASTE WATER	.04903	.04980	.04984	.04979	.04953	.04937	.04897	.04895
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	124.31	122.03	125.54	126.34	121.50	124.50	124.36	119.72
MAIN PLANT	25.83	19.26	22.04	26.17	19.23	21.93	25.88	18.96
DISPOSAL LAND	73.18	74.33	74.38	74.31	73.92	73.68	73.09	73.05
LAND FOR ACCESS RR	25.31	28.44	29.12	25.87	28.35	29.89	25.39	27.71

PARAMETRIC POINT	17	18	19	20	21	22	23	24
COAL, LB/KW-HR	.83033	.82195	.83436	.83102	.82316	.83779	.83604	.83130
SORBANT OR SEED,LB/KW-HR	.43933	.43499	.44195	.43969	.43554	.44329	.44235	.43984
TOTAL WATER, GAL/KW-HR	.912	.861	.940	.912	.861	.943	.917	.871
COOLING WATER	.755	.716	.791	.764	.716	.794	.768	.724
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00782	.00715	.00819	.00791	.00715	.00822	.00785	.00723
WASTE HANDLING SLURRY	.0905	.0900	.0914	.0910	.0902	.0918	.0916	.0910
SCRUBBER WASTE WATER	.04972	.04823	.04895	.04876	.04830	.04915	.04906	.04878
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	122.43	122.30	119.56	122.45	122.08	120.10	123.13	123.24
MAIN PLANT	21.58	25.40	18.94	21.57	25.39	18.98	21.65	25.56
DISPOSAL LAND	72.71	71.98	73.06	72.77	72.08	73.37	73.21	72.80
LAND FOR ACCESS RR	28.14	24.63	27.66	28.11	24.61	27.75	28.27	24.88

PARAMETRIC POINT	25	26	27	28	29	30	31	32
COAL, LB/KW-HR	.83817	.83422	.82582	.82637	.82095	.81007	.82510	.82000
SORBANT OR SEED,LB/KW-HR	.44347	.44138	.43673	.43723	.43436	.42861	.43656	.43386
TOTAL WATER, GAL/KW-HR	.950	.921	.870	.926	.895	.940	.922	.891
COOLING WATER	.801	.773	.724	.779	.749	.697	.775	.745
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00829	.00790	.00723	.00807	.00765	.00696	.00803	.00762
WASTE HANDLING SLURRY	.0918	.0914	.0904	.0905	.0899	.0887	.0904	.0898
SCRUBBER WASTE WATER	.04918	.04895	.04843	.04849	.04817	.04753	.04841	.04811
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	120.47	123.21	122.73	118.35	120.75	119.85	118.05	120.47
MAIN PLANT	19.08	21.72	25.56	18.76	21.31	24.93	18.70	21.24
DISPOSAL LAND	73.40	73.05	72.28	72.36	71.89	70.94	72.25	71.81
LAND FOR ACCESS RR	27.99	28.44	24.39	27.23	27.55	23.97	27.09	27.41

Table 12.34 Continued

FLUIDIZED BED BOILER ADVANCED STEAM SYS   NATURAL RESOURCE REQUIREMENTS

PARAMETRIC POINT	33	34	35	36	37	38	39	40
COAL, LB/KW-HR	.80967	.82837	.82458	.81650	.82360	.81856	.81431	.89902
SORBANT OR SEED,LB/KW-HR	.42840	.43829	.43629	.43201	.43576	.43310	.43085	.47567
TOTAL WATER, GAL/KW-HR	.837	.925	.895	.843	.930	.901	.857	.160
COOLING WATER	.694	.777	.749	.599	.783	.756	.713	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00693	.00835	.00765	.00699	.00839	.00804	.00743	.00833
WASTE HANDLING SLURRY	.0887	.0907	.0903	.0894	.0902	.0897	.0892	.0985
SCRUBBER WASTE WATER	.04751	.04861	.04838	.04791	.04833	.04803	.04778	.05275
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	119.67	118.44	121.05	120.58	126.06	127.37	129.63	199.82
MAIN PLANT	24.91	18.74	21.30	25.03	18.89	21.51	25.43	20.00
DISPOSAL LAND	70.90	72.54	72.21	71.50	72.12	71.68	71.31	78.73
LAND FOR ACCESS RR	23.85	27.16	27.54	24.04	35.04	34.18	32.89	101.09

PARAMETRIC POINT	41	42	43	44	45	46	47	48
COAL, LB/KW-HR	.99580	.99273	.77413	.77498	.77491	.73960	.74092	.74235
SORBANT OR SEED,LB/KW-HR	.47450	.47234	.40959	.41004	.41001	.39132	.39202	.39278
TOTAL WATER, GAL/KW-HR	.159	.157	.843	.823	.787	.763	.745	.714
COOLING WATER	.000	.000	.704	.684	.649	.630	.612	.582
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00794	.00726	.00848	.00814	.00755	.00856	.00823	.00767
WASTE HANDLING SLURRY	.0992	.0978	.0948	.0949	.0849	.0910	.0811	.0813
SCRUBBER WASTE WATER	.05262	.05238	.04542	.04547	.04547	.04340	.04347	.04356
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	200.07	199.81	109.32	112.04	115.89	104.39	107.13	111.16
MAIN PLANT	22.81	26.98	13.13	20.74	24.62	17.51	20.06	23.89
DISPOSAL LAND	78.53	78.18	67.79	67.86	67.86	64.77	64.88	65.01
LAND FOR ACCESS RR	98.73	94.65	23.40	23.43	23.40	22.11	22.18	22.26

PARAMETRIC POINT	49	50	51	52	53	54	55	56
COAL, LB/KW-HR	.97862	.97637	.97050	1.29902	1.29605	1.28825	.00000	.00000
SORBANT OR SEED,LB/KW-HR	.11117	.11092	.11025	.12390	.12362	.12287	.00000	.00000
TOTAL WATER, GAL/KW-HR	.884	.858	.813	.888	.86_	.817	.000	.000
COOLING WATER	.805	.790	.735	.807	.781	.737	.000	.000
GASIFIER PROCESS H2O	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
CONDENSATE MAKE UP ,	.00934	.00797	.00735	.00935	.00799	.00736	.00000	.00000
WASTE HANDLING SLURRY	.0230	.0230	.0228	.0256	.0256	.0254	.0000	.0000
SCRUBBER WASTE WATER	.04752	.04751	.04723	.04754	.04744	.04715	.00000	.00000
NOX SUPPRESSION	.00000	.00000	.00000	.00000	.00000	.00000	.00000	.00000
TOTAL LAND ACRES/100MWE	75.37	78.56	78.96	78.46	81.65	82.03	.00	.00
MAIN PLANT	19.14	21.84	25.81	19.18	21.88	25.86	.00	.00
DISPOSAL LAND	28.08	29.02	27.85	31.08	31.01	30.83	.00	.00
LAND FOR ACCESS RR	28.15	28.70	25.30	28.20	28.76	25.34	.00	.00

@BRKPT PRINTS

12.8 References

12.1 R. G. Rincliff et al,, "The Eddystone Story; Unit 1 Extends Power Plant Technology," Electrical World, March 11, 1963.

12.2 W. P. Gorgzegno and R. J. Zaschak, "Supercharging the Once-Through steam Generator," ASME Paper 64-PWR-15, September 1964.

12.3 D. L. Keairns et al, "Evaluation of the Fluidized-Bed Combustion Process - Volume I, Pressurized Fluidized-Bed Combustion Process Development and Evaluation," EPA-650/2-73-048a, December 1973.

12.4 N. Weeks, Westinghouse report 66-1D8-FLINJ-R2, 1966.

Appendix A 12.1

STEAM TURBINE PRICING AND EQUIPMENT CONFIGURATION

A 12.1.1 Basis for Turbine Pricing

It is common practice throughout the electric utility industry to price equipment from published list prices. Westinghouse has such a price list for steam turbine-generator units, a copy of which (for fossil units) is included in this appendix, (Subappendix AA 12.1.1).

Such a price list reflects primarily those units and specifications currently, or expected to be, accepted within the industry. This study, however, involved specifications relative to pressures and temperatures not entirely covered by this price list. Since the list is, in general, designed to reflect our costs, however, it has been possible by means of estimating costs for the higher-temperature applications to extend this price list to produce estimated turbine-generator prices for most of the future applications requested.

One convenient operation is to identify the price structure in terms of high-pressure components, low-pressure components, and generators. By identifying pricing modifications in these categories and adding them together in accordance with required modifications, a new selling price can be obtained.

The turbine selling price is obtained by adding the selling price of the low-pressure turbine to that of the front end of the turbine. The front end consists of an HP turbine, a combined HP-IP turbine or a separate HP and IP turbine. The front-end incremental list price is \$9/kW. This includes, as mentioned above, the HP, IP or combined HP-IP turbine, the digital EH controller, technical direction of installation (at \$0.36 kW + \$56,000), and the miscellaneous heat exchangers.

The generator list price is based on the incremental kVA list price of \$7.50/kVA. To relate this to kilowatts, multiply the kVA by 1.2, which translates into an incremental list price of \$9/kW. The generator price includes the generator frame itself; a brushless exciter; a voltage regulator; and the hydrogen, seal oil, and exciter air coolers. It also includes a stator water cooler if the generator is water cooled.

Since there are a large number of frames for front ends, heat exchangers, and generators when costs are plotted, they appear as a series of step functions. The steps over the wide range of kW are rather small and can be approximated by a straight line. The costs are then translated into a list price with the algorithm \$ = 18 kW + \$4,250,000. This means that for any kW rating, the front-end turbines and the generator are sold in accordance with the above algorithm for list price. The list price is subject to the current multiplier to obtain the net price, which includes the necessary charges for overhead and a reasonable profit for Westinghouse.

The low-pressure turbine list prices are shown on Table A 12.1.1. First, there is a base list price for each double-flow end. For the two-flow 0.724 m (28.5 in) end, it is \$4,600,000. Because miscellaneous items are added or subtracted, depending on the configuration, the base list price for a given end is modified for such a configuration. Table A 12.1.1 also shows the modified list price for a two-flow machine, and addition for the second element to comprise a four-flow machine, together with the total four-flow list price. Then it shows the addition for a six-flow machine together with the total six-flow list price.

The list price then consists of <u>large step</u> changes such as the low-pressure turbines and <u>small step</u> changes which are translated into a straight line algorithm. For a given megawatt rating, the purchaser has the option of selecting a small end at lower cost and higher heat rate, or a larger end at higher costs, but with lower heat rate, and can then make his own evaluation as to which end to select. The front end and generator would not change, however, since they are strictly functions of kilowatt rating.

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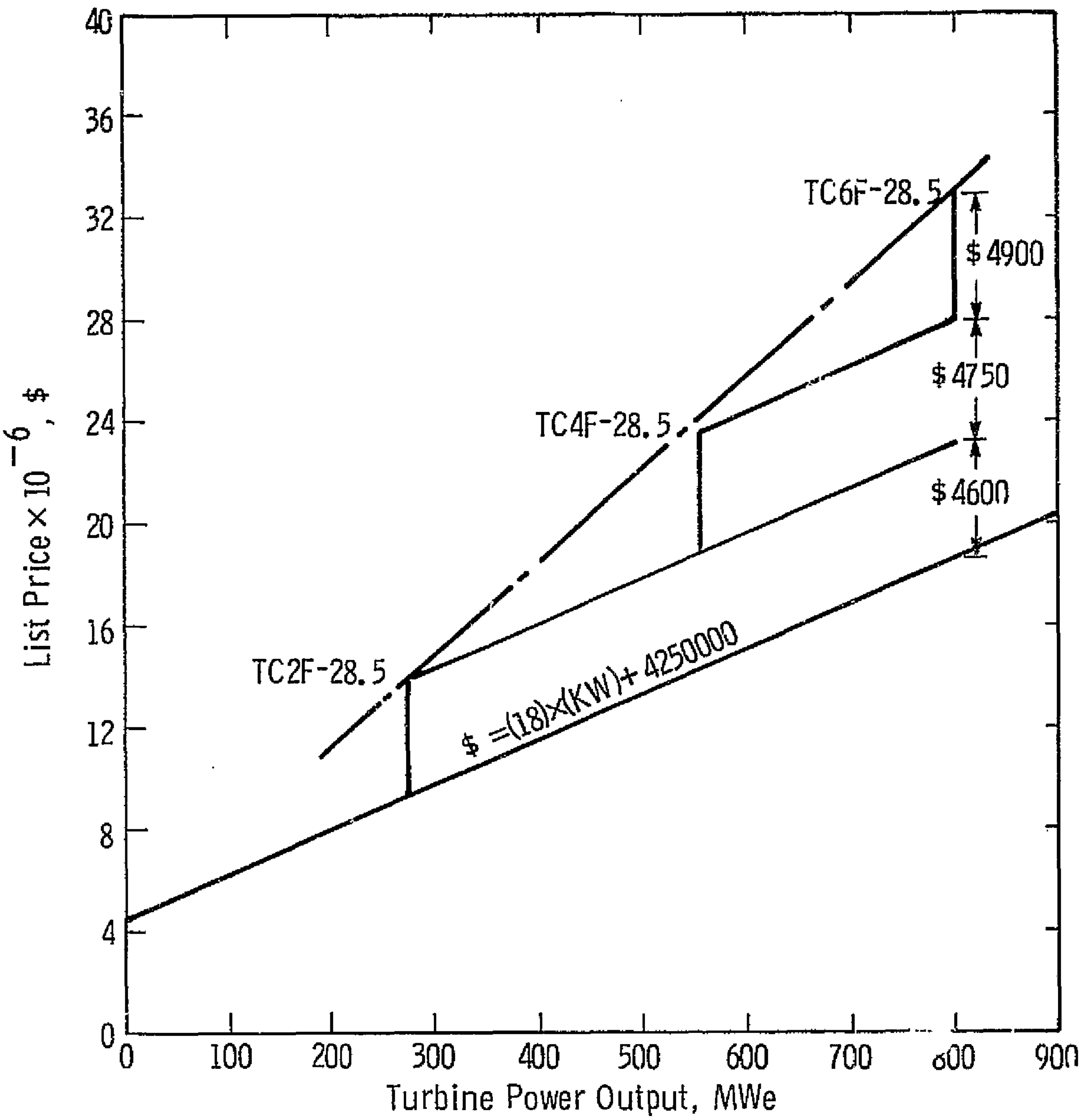

Fig. A 12.1.1—List price vs MW rating tandem-compound 3600 RPM 28.5 in end turbines

Table A 12.1.2 below shows how the list prices in Price List No. 1252 were constructed. The base megawatt ratings selected were nominal ratings at fairly light end loadings of the turbine. For an actual negotiation, the given low-pressure back end may be loaded up to its maximum limit and no additional charges made for the low-pressure end. Since the steam flow to the front end increases, however, the front end components are increased in size, and the increased cost must be reflected in the price. Increases in kilowatt rating start only from the listed base rating. For example, if a double-flow 0.635 m (25 in) end machine were rated at 250 MWe, there would be a charge of $18/kW only for the additional 50 MW.

Figure A 12.1.1 shows schematically the base line and additions for a six-flow 0.724 m (28.5 in) end machine.

In making any modifications to the printed price lists, the same framework is kept, with any new or extrapolated items following the same pattern for increased costs.

The price additions for pressure and temperature were constructed in the same way - that is, taking into account the increased cost for materials or volumetric flow. Subsequently, the net selling prices and list prices were calculated on the basis of costs.

Table A 12.1.1 - List Price Built-up Low-Pressure Ends x 10^{-3}, $

LP End	25 in	28.5 in	31 in
Base (standard)	3,500	4,600	5,300
As Modified:			
2F	3,050	4,600	5,700
Add for 4F	3,950	4,750	5,550
TOTAL 4F	7,000	9,350	11,250
Add for 6F	--	4,900	5,500
TOTAL 6F	--	14,250	16,750

Table A 12.1.2 - List Price No. 1252 $\times 10^{-3}$, \$

LP End	Base MW	Base Cost (MW)18+4250	Add for LP End	Total List
2-25	200	7,850	3,050	10,900
2-28.5	275	9,200	4,600	13,800
2-31	325	10,100	5,700	15,800
4-25	425	11,900	7,000	18,900
4.28.5	550	14,150	9,350	23,500
4-31	650	15,950	11,250	27,200
6-28.5	800	18,650	14,250	32,900
6-31	950	21,350	16,750	38,100

A 12.1.2 Added Tables for Westinghouse Price List 1252

Table A 12.1.3 - Basic List Prices for High Back Pressure Units Including Technical Direction of Installation and Freight; 3600-RPM, Single Shaft

Basic Unit Turbine Rating, kW	Generator Rating, kVA	Turbine Exhaust Ends	Basic List Price $\times 10^{-3}$, \$
325,000	390,000	2 - 23 in Hg abs*	16,200
650,000	780,000	4 - 23 in Hg abs*	27,900

* H denotes LRB designed for high exhaust pressures.

The turbine ratings as listed are the maximum guaranteed kilowatts at 27.090 kPa (8 in Hg) abs exhaust pressure and 3% makeup.

The turbines are suitable for operation at exhaust pressures up to 50.795 kPa (15 in Hg) abs.

Exhaust pressure and makeup correction factors to be used in a manner similar to those shown on page 6 of PL-1252 are as follows:

Table A 12.1.4 - Exhaust Pressure and Makeup Correction Factors

Corrections for Exhaust Pressure		Corrections for Makeup	
Exhaust Pressure, in Hg abs	X	Makeup, %	Y
5.0	0.030	3.0	0
6.0	0.020	2.0	0.003
7.0	0.010	1.0	0.006
8.0	0	0	0.009
9.0	-0.010		
10.0	-0.020		
11.0	-0.030		
12.0	-0.040		
13.0	-0.050		
14.0	-0.060		
15.0	-0.070		

The maximum allowable exhaust flow is 123.48 kg/s (980.000 lb/hr/row) LRB at 27.09 kPa (8 in Hg) abs exhaust pressure with zero makeup flow and as otherwise defined in Exhaust Loading Limits of PL-1252.

Table A 12.1.5 Price Additions for Pressure, psig

Turbine Rating, kW	Initial Pressure Range, psig 4600-5000
500,000	$3,250,000
900,000	$4,000,000

Table A 12.1.6 - Price Additions for Temperature, °F

Turbine Rating, kW	Price Additions x 10^{-3}, \$ Initial Temp Range		Price Additions x 10^{-3}, \$ First Reheat Temp Range		Price Additions x 10^{-3}, \$ Second Reheat Temp Range	
	1101-1200	1201-1400	1051-1200	1201-1400	1051-1200	1201-1400
500	15,000	45,000	15,000	30,000	35,000	70,000
900	15,000	45,000	20,000	40,000	35,000	70,000

A 12.1.3 Discussion of Pricing

A 12.1.3.1 Introduction

The limiting factors in designing and building turbines with steam temperatures higher than 811°K (1000°F) in large ratings are the materials required to contain the high temperatures and the availability of these materials in the large quantities required.

Another problem which arises when the initial temperatures are greater than 811°K (1000°F) is that the inlet temperature to the low-pressure turbines exceeds 661°K (730°F), also a limiting factor.

The problem then is narrowed down to two specific areas. First, materials must be available to contain the high temperatures in the quantities required for the high-pressure portion of the turbine; and second, some method must be used to overcome the 661°K (730°F) inlet temperature limit to the low-pressure turbines.

Materials are available for the high-pressure portion of the turbine designed for 922 and 1033°K (1200 and 1400°F), but in relatively small quantities. The high-pressure elements would have to be designed with disk construction for the rotors, since it is anticipated that even in 1990 large ingots of the sizes required would not be available.

The prices in tha attached summary assume that the technology will exist by 1990 to provide the materials required in the sizes and quantities required for at least the disks.

The prices in the summary do not include any money required for the development of various items listed where new technology is required, or for any capital investment required to produce the materials required.

It was assumed that turbines with a normal 294.3 Ms (30 yr) life were required.

A 12.1.3.2 Low-Pressure Elements

In those cases where the inlet temperature to the low-pressure turbines would have exceeded 661°K (730°F) using normal designs -- that is, in every case where the last reheat temperature was either 922°K (1200°F) or greater -- the design philosophy was to take the temperature drop in an interposed intermediate pressure element so that the steam entering the low-pressure element would not see temperatures higher than 661°K (730°F). This requires that the low-pressure elements be designed with larger steam inlets because of the greater volumetric flow, and that the first few stages of blades be removed, down to the first extraction point. In pricing the low-pressure elements, it was assumed that the costs, and consequently price, do not change, because the omission of the blades would offset the additional cost of the larger steam inlets.

The temperature of a low-pressure element could be extended to 700°K (800°F) with a rotor heat soak, but this will not help much because the rotor would operate at lower temperatures than its transition temperature after start-up. This is another area where, if technology of metallurgy were improved to the point where materials are available for low-pressure rotors to take the higher temperatures, the design of the overall turbine would be simplified by eliminating some of the IP elements.

A 12.1.3.3 High-Pressure Elements

In addition to the problem of designing for temperatures greater than 811°K (1000°F), a less serious problem is that of pressures. This study will concern itself only with the 34.47 MPa (5000 psig) initial pressure, which is not in the current price list. For the 34.47 MPa (5000 psig) initial pressure, the only additional requirement over 24.13 MPa (3500 psig) design is an increase in wall thickness, which is directly proportional to the pressure ratio. For a thin wall cylinder, as an example, the following algorithm demonstrates the point:

$$\text{Thickness, in} = \frac{(\text{Internal Pressure, psi})(\text{Radius, in})}{(\text{Allowable Stress Level, psi})}$$

For this study, the pressure addition table has been extended and included in this report as Table A 12.1.5.

We can now address ourselves to the main problem -- that is, the high temperatures.

A 12.1.3.4 High Temperatures

The present technology for initial and reheat temperatures is based on 811 and 839°K (1000 and 1050°F). See Table A 12.1.7 for a list of these materials for the major components of a turbine.

For 922°K (1200°F) temperatures, the material problem is a little more acute, although the technology exists. The rotor forging availability is limiting. The materials are available only in small quantities. DISCALOY, the material used in the Eddystone turbine, is also subject to segregation on solidification of the rotor. Also, there is danger of stress corrosion of austenitic materials. The original DISCALOY forging for Eddystone No. 1 was melted in air. If done today, it would probably be melted in a vacuum furnace, which would help alleviate some of the metallurgical problems. This study is based on using refractaloy for 922°K (1200°F) materials.

The design of turbines for 1033°K (1400°F) temperatures is a little more difficult. Materials are available, but here again, size if the limiting factor. While castings do not represent as severe a problem, the rotor forgings are at present on the critical path. The heat limits production of good forgings. The materials used in this study for 1033°K (1400°F) is Waspaloy. The present limitation for Waspaloy ingots is 6350 kg (14,000 lb), or a billet of about 0.762 m (30 in) diameter by 3 m (118 in) long. It is assumed that by 1990, ingots of 907 kg (20,000 lb) will be available.

A 12.1.3.5 Configurations

Even with the limitations imposed by the materials, turbines can probably be designed and built. By isolating the high temperatures in separate elements, the high temperatures can be contained at the front end of the turbine and conventional elements can be used downstream. The number of elements required would be consistent with the largest element available based on the material quantities available.

The basis for pricing given in this report is the cost of the equipment supplied. For purposes of determining costs, configurations for

Table A 12.1.7 – Materials

Temperature/Part	Type	Material	Composition
1. 1000/1050°F			
a. Rotor	F	Ferritic Alloy Steel	1-Cr 1-Mo 1/4-V
b. Blades	B	SS Type 422	12-Cr
c. Inner Cyl.	C	Cr-Mo Steel	2-1/4-Cr 1-Mo
d. Outer Cyl.	C	Cr-Mo Steel	1-1/4-Cr 1/2-Mo
2. 1200°F			
a. Rotor	F	Refractaloy	18-Cr 40-Ni 20-Cr Fe
b. Blades	B	Refractaloy	
c. Inner Cyl.	C	Austenitic Alloy Steel Type 316	17-Cr 12-Ni 2-1/2-Mo
d. Outer Cyl.	C	Ferritic Alloy Steel	2-1/4-Cr 1-Mo
3. 1400°F			
a. Rotor	F	Waspaloy	19-Cr 13-Co 4-Mo 3-Ti 1.3-Al 59.7-Ni
b. Blades	B	Udimet 500	19-Cr 18-Co 4-Mo 3-Ti3-Al 53-Ni
c. Inner Cyl.	C	Austenitic Alloy Steel Type 316	
d. Outer Cyl.	C	Austenitic Alloy Steel Type 316	

C = Casting

F = Forging

B = Bar Stock

the high-pressure portion of the turbines have been assumed and have been factored into the costs. All of the 500 MWe units were based on four-flow low-pressure ends, and the 900 MWe were based on six-flow low-pressure ends.

For purposes of this study, the high-pressure configurations will not be delineated into the number and size of cylinders or the type of cylinders and their pressure and temperature ranges. This is the practice followed in pricing the normal fossil product line. The front end for high-pressure elements could consist of a superpressure element, a VHP-HP element, an HP element, an IP element, or a combined HP-IP element. Where multiple cylinders were used in tandem, and the number of HP elements approached five or six elements, complications arose. For example, only one thrust bearing is permitted per shaft, and a long string of turbine elements complicated the situation. To overcome this problem, some of the turbines were designed and priced as cross-compound turbines. This step was taken where the preliminary configuration indicated that there were five or more elements in the high-pressure portion of the turbine. The main difference is that cross-compound units have two half-size generators instead of one full-size generator. As far as the turbine is concerned, there is no physical change in weights and dimensions, other than having two separate shafts. All of the turbines would operate at 60 rps (3600 rpm).

A 12.1.3.6 Costing

Every element utilizing the high temperatures was costed by using empirical methods. Since the high-temperature material costs are much greater than 811°K (1000°F) materials, and since the working of the materials is difficult, the prices calculated include the labor and materials for the high-temperature elements; but the overheads were included only as a fixed dollar value and not as a factor on the entire element.

One reference for costing where existing cylinders were not applicable was the Philadelphia Electric Company's Eddystone No. 1 turbine.

The Eddystone No. 1 machine is a two-flow, 1.12 m (44 in) cross-compound machine rated at 325 MWe. It was shipped in July 1958 and consists of two LP elements, each a single-flow 1.12 m (44 in) end machine operating at 1800 rpm, and a superpressure element, a VHP-HP element and an IP element for the HP portion of the turbine. Initial pressure is 34.474 MPa (5000 psig) and the initial temperature is 922°K (1200°F). The throttle flow is 252 kg/s (2×10^6 lb/hr). This unit has a first reheat temperature of 839°K (1050°F) and a second reheat temperature at 839°K (1050°F). The Eddystone No. 1 turbine used a DISCALOY rotor weighing approximately 1587.6 kg (3500 lb). The shell is a ferritic alloy cast steel, Type 316. The nozzle and inlet steam pipings are castings of austenitic steel, Type 316. All parts in contact with the 34.474 MPa (5000 psig), 922°K (1200°F) steam are Type 316 alloy steel.

The outer shell of the VHP-HP element is 1 Cr, 1/2 Mo alloy steel. The inner shell or blade ring for the VHP section is 2-1/4 Cr, 1 Mo, 1-1/4 V alloy steel.

A 12.1.3.7 Price List Tables

The pricing of the turbines and generators for the Advanced Steam Systems was done within the framework of existing Westinghouse price lists. After the configurations were costed, new tables were developed for the higher temperature (Table A 12.1.6) and pressure (Table A 12.1.5) as extensions of existing price lists. A new table is included for the high back-pressure turbines (Tables A 12.1.3 and A 12.1.4.)

Of all the items supplied in the T-G Bill of Material, as detailed in the price list, the generator, TD of I, miscellaneous heat exchangers, turbine control system and generator control system are not affected by the high initial temperature or the pressure. The existing price list can be used for these, in addition to any other extra features and accessories required.

A 12.1.3.8 Prices

The prices given are the net selling prices, or customer costs, which were in effect for shipments made in mid-1974. These were based on the list price times the multiplier of 0.57, which was a typical billing multiplier for that period. The multiplier for turbines ordered in mid-1974 for delivery before mid-1977 is 0.71. Prices on deliveries made after this date are subject to escalation. This study assumed delivery of steam turbines ordered in mid-1974 and delivered during the two-year fixed price period. To correct to prices for units ordered in mid-1974, the prices given must be multiplied by 1.2456.

A 12.1.4 Summary of Pricing for 500 MW and 900 MW Turbine-Generators

The following tabulations are summaries of prices for the items requested. For the 500 MW T-G, there are 28 propositions listed. In addition, to those requested, the Steam Turbine Division added two other propositions: Item 5-I and 7-I. All of the propositions are based on a 6.773 kPa (2 in Hg) abs back pressure. However, Items 1, 9, 16, 17, and 20 were also priced with 11.852 kPa (3.5 in Hg) abs back pressure and 30.477 kPa (9 in Hg) abs back pressure. Item 1, the 68.947 MPa (10,000 psig) initial pressure turbine is listed in the tabulation but was not priced.

In seven of the cases, the prices could be prepared from existing price lists without modifications.

For the 900 MWe turbine, the same item numbers were kept, based on initial conditions of the steam to the turbine. These are Items 2-5, 8-11, 16, and 17. Four of these items could be priced directly from our existing price lists. All of these propositions were prepared with 6.773 and 11.852 kPa (2 and 3.5 in Hg) abs back pressure.

The typical price list calculation is shown below. For the 500 MWe plant, a 600 MVA generator was selected with a 0.90 power factor (pf) and 0.58 short circuit rating (SCR). For the 900 MWe plant, a 1080 MVA generator was selected.

For the 500 MW_e plant, a TC4F 0.635 m (25 in) turbine was used for the 11.852 kPa (3.5 in Hg) abs back pressure; a TC4F 0.724 m (28.5 in) turbine was used for the 6.773 kPa (2 in Hg) abs back pressure and a TC4F 0.584 m (23 in) turbine was used for the 30.477 kPa (9 in Hg) abs back pressure. The high back-pressure price list is one of the additions to the regular printed price lists.

For the 900 MWe plant, a TC6F 0.724 m (28.5 in) turbine was used for the 11.852 kPa (3.5 in Hg) abs back pressure and a TC6F 0.787 m (31 in) turbine was used for the 6.773 kPa (2 in Hg) abs back pressure. There were no propositions for the 30.477 kPa (9 in Hg) abs back pressure.

All of the prices include a generator neutral enclosure.

Table A 12.1.8 - Typical Price Calculation, 500 MW - Item 3

Guaranteed Rating - 500,059 kW @ 2 in Hg abs and 0% makeup

Correction for Back Pressure and Makeup - 1.000-0.015-0.009 = 0.976

Pricing Rating - 500,059 x 0.976 = 488,050 kW

Use 488,000 kW for study

Base Price kW - 500,000 MW

Generator Rating - 600,000 kVA

Base Generator kVA - 660,000 kVA

Exhaust End - TC4F - 28.5

		Pricing x 10^{-3}, $
I.	Base Price - TC4F - 28.5	23,500
II.	kW Adder at $9,00/kW (488,000-500,000) 9.00	(-) 558
III.	kVA Adder at 7.30/kVA (600,000-660,000) 7.50	(-) 450
IV.	Pressure Adder, 5000 psig	3,250
V.	Temperature Adders Initial Temp. 1200°F	15,000
	1st Reheat Temp. 1200°F	15,000
	2nd Reheat Temp. 1200°F	35,000
VI.	Cross-Compounding	2,500
VII.	Accessories	
	Gen. Neutral Enclosure	36
Total List Price		93,278
Total Net Price (0.57 mult.)		53,168

Table A 12.1.9 - Pricing Summary
500 MWe

Item	Initial Press, Psig	Initial T, °F	1st Rht, °F	2nd Rht, °F	3rd Rht, °F	1974 Net Selling Prices x 10^{-3}, $ * 2 in Hg abs	3.5 in Hg abs	9 in Hg abs	Remarks
1	10000	1000	1000	1000	1000				
2	5000	1000	1000	1000		15,635			
3	5000	1200	1200	1200		53,168			Cross-compound
4	5000	1400	1400	1400		98,768			Cross-compound
5	5000	1000	1200	1200		44,618			Cross-compound
5I	5000	1000	1200	1400		64,568			Cross-compound
6	5000	1000	1000	1400		56,018			Cross-compound
7	3500	1000	1000	1000		13,811			
7I	3500	1000	1000	1000		--			
8	3500	1000	1200	1200		42,774			Cross-compound
9	3500	1000	1000			12,849	11,545	14,385	
10	3500	1200	1200			29,949			
11	3500	1400	1400			55,599			
12	3500	1000	1200			21,399			
13	3500	1000	1400			29,949			
14	3500	1200	1400			38,499			
15	3500	1400				41,349			
16	2400	1000	1000			12,901	11,608	14,453	
17	2400	1200	1200			30,001	28,708	31,553	
18	2400	1400				41,401			
19	2400	1000	1200			21,451			
20	2400	1200	1400			38,551	37,258	40,103	

* For units shipped in 1974.

Table A 12.1.10 - Pricing Summary
900 MWe

Item	Initial Press, Psig	Initial T, °F	1st Rht, °F	2nd Rht, °F	1974 Net Selling Prices x 10^{-3}, $* 2 in Hg abs	1974 Net Selling Prices x 10^{-3}, $* 3.5 in Hg abs	Remarks
2	5000	1000	1000	1000	24,593	23,247	
3	5000	1200	1200	1200	64,562	63,152	Cross-compound
4	5000	1400	1400	1400	113,012	111,602	Cross-compound
7	3500	1000	1000	1000	22,313	20,967	
8	3500	1000	1200	1200	53,732	52,322	Cross-compound
9	3500	1000	1000		21,128	19,775	
10	3500	1200	1200		41,078	39,725	
11	3500	1400	1400		69,578	68,225	
16	2400	1000	1000		21,767	20,442	
17	2400	1200	1200		41,717	40,392	

* For units shipped in 1974.

Subappendix AA 12.1.1

PRICE LIST 1252

Steam Turbine Generator Units

Condensing Non-Reheat and Reheat Double Flow 25-inch Last Row Blades and Larger

Attached is revised Westinghouse Price List 1252, covering large turbine generators. Please destroy previous Price List 1252 dated July 1, 1974.

The following is a tabulation of current pages and their dates:

Price List	Pages	Date
1252	1,2	October 30, 1974
1252	3,4	October 30, 1974
1252	5,6	October 30, 1974
1252	7,8	October 30, 1974
1252	9,10	October 30, 1974
1252	11,12	October 30, 1974
1252	13,14	October 30, 1974
1252	15,16	October 30, 1974
1252	17,18	October 30, 1974
1252	19,20	October 30, 1974
1252	21,22	October 30, 1974
1252	23,24	October 30, 1974
1252	25,26	October 30, 1974
1252	27,28	October 30, 1974
1252	29,30	October 30, 1974
1252	31,32	October 30, 1974

Westinghouse Electric Corporation
Steam Turbine Division
Philadelphia, Pennsylvania 19113
Printed in U.S.A.

October 30, 1974
Supersedes Price List 1252,
Page .01 dated July 1, 1974
E,C/1683/PL

Westinghouse

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Conditions of Sale

①Selling Policy (Price Adjustment)
The price of the equipment is subject to adjustment upward or downward for changes in labor and materials costs and changes in the GNP Deflator. This adjustment will apply to each pa... which is due in August 1976 and later, and will be determined in accordance with the following method:

A. Definitions
For the purpose of this price adjustment provision only, the following definitions apply:

Labor Index will be the final Average Hourly Earnings in the Steam Engine and Turbine Industry (SIC-3511) published by the Bureau of Labor Statistics, U.S. Department of Labor, for "Employment and Earnings."

Material Index will be the final Iron and Steel Index (Code 101) published by the Burear of Labor Statistics, U.S. Department of Labor, in "Wholesale Prices and Price Indices."

GNP Deflator will be the Gross National Product Implicit Price Deflator published by the U.S. Department of Commerce in the Survey of Current Business for the third quarter of 1976 or the calendar quarter which contains the Reference Month.

Base Labor Index and Base Material Index

Each Base Index will be determined by averaging that index for the months of June, July and August, 1976.

Base GNP Deflator is that for the third quarter, 1976.

Reference Month will be the month in which the payment to be adjusted is due.

B. Labor Adjustment Component
For the purpose of adjustment, the proportion of each payment representing Labor is established as 50 percent.

The above amount representing Labor will be adjusted for changes in labor costs. The Base Labor Index will be compared with the Labor Index for the Reference Month and a percentage increase or decrease will be determined. The adjustment for changes in Labor will be calculated by multiplying such percentage of increase or decrease by the amount of the payment representing Labor, as indicated above, and the result will be the increase or decrease in the payment.

① Changed since previous issue.

Prices effective October 30, 1974; subject to change without notice.

C. Materials Adjustment Component
For the purpose of adjustment, the proportion of each payment representing Material is established as 40 percent.

The above amount representing Material will be adjusted for changes in material costs. The Base Material Index will be compared with the Material Index for the Reference Month and a percentage increase or decrease will be determined. The adjustment for changes in Material will be calculated by multiplying such percentage of increase or decrease by the amount of the payment representing Material, as indicated above, and the result will be the increase or decrease in the payment.

D. Profit and Overhead Adjustment Component
For the purpose of adjustment, the proportion of each payment representing Profit and Overhead is established as 10 percent. The above amount representing Profit and Overhead will be adjusted for the rate of inflation or deflation. The Base GNP Deflator will be compared with the GNP Deflator for the Calendar quarter which contains the Reference Month and a percentage increase or decrease will be determined. The adjustment for changes in Profit and Overhead will be calculated by multiplying such percentage of increase or decrease by the amount of the Payment representing Profit and Overhead, as indicated above, and the result will be the increase or decrease in the payment.

E. General
A provisional adjustment will be made to the Labor, Material, and Profit and Overhead content of each payment at the time of billing. This adjustment will be calculated as in paragraphs B, C and D using the Westinghouse estimate of the Labor Index and Material Index for the Reference Month and GNP Deflator for the calendar quarter which contains the Reference Month. Revisions to this provisional adjustment, if necessary, will be made at the time the final indices are published. If a published final index is revised within one month of initial publication, the revised final index will be used for purposes of price adjustment. No other adjustment will be recognized for changes in Labor, Material or GNP Deflator.

The Base Labor Index will be determined to the nearest second decimal place. The Base Material Index will be determined to the nearest first decimal place. The Base GNP Deflator will be determined to the nearest second decimal place. Labor, Material, and Profit and Overhead percentage increase or decrease will be calculated to the nearest one-tenth of one percent. In any case, if the next succeeding place is five or more, the preceding decimal place will be raised to the next higher figure.

Changes in the base year(s) reporting basis, minor changes in the weighting and minor changes in benchmarks will not be construed as substantial modification to the indices. Price adjustments will be calculated such that Base indices are consistent with current indices reported by the U.S. Government.

Should the specified indices be discontinued, or should the basis of their calculation be substantially modified, proper indices will be substituted by mutual agreement of Purchaser and Westinghouse.

Payments due and payable after the month of shipment shall be adjusted through the month of shipment.

In the event of a change in contract price, the revised contract price shall be considered as having been in effect from the date of the original commitment for the purpose of price adjustment. The resulting increase or decrease in contract price will be reflected in payments due and payable beginning one month after agreement on the change in price. The first such payment on the basis of the revised contract price shall include a lump sum payment to account for the difference between payments already made by the Purchaser, and the payments (including price adjustment), which would have been due and payable had the revised contract price been in effect from the date of the original commitment.

Except as provided below, this Selling Policy is applicable to each turbine-generator scheduled for shipment in July, 1981 or earlier. For each turbine-generator scheduled for shipment in August, 1981 or later the price of such turbine-generator shall be determined by the Westinghouse Selling Policy which first becomes effective for such shipment.

This Selling Policy is also applicable to each turbine-generator on a multiple unit order for duplicate units provided the scheduled shipment date(s) is July, 1984 or earlier and provided further that at least one (1) turbine-generator is scheduled for shipment in July, 1981 or earlier. For each turbine-generator on such order scheduled for shipment in August, 1984 or later the price of such turbine-generator shall be determined by the Westinghouse Selling Policy which first becomes effective for such shipment.

October 30, 1974
Supersedes Price List 1262, dated July 1, 1974
E, C/1683/PL

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Conditions of Sale, Continued

For the purpose of Selling Policy the shipment date is defined as the date the last of the following parts is transferred to the carrier: bearing pedestals, outer and inner turbine cylinders and generator stator.

①Quotations
Quotations will expire sixty days after the date of quotation. Should Westinghouse announce a price increase prior to the expiration of the 60 day quotation validity period, then the quotation will expire in accordance with the provisions of such announcement.

①Taxes
The price does not include any Federal, state or local property, license, privilege, sales, use, excise, gross receipts or other like taxes which may now or hereafter be applicable to, measured by or imposed upon or with respect to the transaction, the property, its sale, its value or its use, or any services performed in connection therewith. Purchaser agrees to pay or reimburse any such taxes which Westinghouse or Westinghouse's subcontractors or suppliers are required to pay.

①Terms of Payment
Payment shall be made in U.S. dollars by the Purchaser to Westinghouse in accordance with the following standard terms of payment:

a. 1% of the contract price, as adjusted by the Selling Policy, in each of the first six calendar months after the date of Written Release

b. 2% of the contract price, as adjusted by the Selling Policy, in each of the 24th through the 13th calendar months prior to the month of scheduled shipment.

c. 3.5% of the contract price, as adjusted by the Selling Policy, in each of the 12th through the 7th calendar months prior to the month of scheduled shipment.

d. 6% of the contract price, as adjusted by the Selling Policy, in each of the 6th through the 1st calendar months prior to the month of scheduled shipment.

e. 6% of the contract price, as adjusted by the Selling Policy, together with all unpaid adjustments in the month of scheduled shipment.

f. 5% of the contract price, as adjusted by the Selling Policy, 60 days after the shipment date.

g. 2% of the contract price, as adjusted by the Selling Policy, together with all remaining unpaid adjustments one year after the shipment date.

Each of the payments detailed in "a" through "e" above shall be due and payable on the 15th day of the month in which they are due.

In the event that Purchaser and Westinghouse agree to a date of Written Release less than 30 months prior to scheduled shipment, the Purchaser shall make uniform percentage payments from the month of Written Release through the 13th month prior to scheduled shipment so that a cumulative total of 30% of the contract price, as adjusted by the Selling Policy, is paid by the 13th month before scheduled shipment.

Unless otherwise agreed, no payment shall be deemed to constitute an acceptance of the equipment or a release of any responsibility on the part of Westinghouse.

For the purpose of Terms of Payment the shipment date is defined as the date the last of the following parts is transferred to the carrier: bearing pedestals, outer and inner turbine cylinders and generator stator.

If the Purchaser requests minor changes in terms of payment less favorable to Westinghouse than the standard terms of payment above, and where the proposed minor changes are acceptable to Westinghouse, a time-price differential will be charged as outlined below.

1. Westinghouse will require payment of a time-price differential (equal to 15 percent per annum) compounded annually on the difference between the contracted terms of payment and the standard terms of payment outlined in "a" through "g" above.

2. The time-price differential shall be established prior to the date of Written Release and shall be added to the contract price. The price adjustment provisions of the Selling Policy shall not be affected by such change in terms of payment.

There will be no reduction in price for terms of payment which are more favorable to Westinghouse than the standard terms of payment.

①Payments
If, in the judgement of Westinghouse, at any time during the manufacturing period, or at the time the equipment is ready for shipment, reasonable grounds for insecurity arise with respect to the ability of Purchaser to make payment as required, Westinghouse may in writing demand adequate assurance of payment and until Westinghouse receives such assurance it may suspend manufacture or shipment.

If Purchaser and Westinghouse agree to change the shipping date to a date earlier than originally scheduled, Purchaser shall make a payment on the 15th day of the month following the date of change, which payment shall include the difference between the payments already made by the Purchaser and the payments, including price adjustment, which would have been due by the 15th day of month following confirmation by Westinghouse of the earlier shipping date had the Purchaser selected the earlier shipping date at the time of the Written Release. All subsequent payments shall be based on the revised (earlier) shipping date.

①Suspension or Extension
At any time prior to twelve months from the previously scheduled shipping date Purchaser may by written notice to Westinghouse request a later shipping date. If Westinghouse agrees to the revised shipping date Purchaser shall pay to Westinghouse, within fifteen days of notice to Purchaser of the revised shipping date, the difference between the value of the work performed (based upon the contract price, as adjusted by the Selling Policy, and percentage completion) and the sum of the payments made prior to the date of revision. Upon establishment of a revised shipping date the contract price shall be increased to reflect the costs resulting from the extension. With the establishment of a revised shipping date and contract price a new payment schedule will be determined assuming that the revised shipping date and contract price had been in effect from the date of Written Release. Purchaser will resume payments when the cumulative payments (including price adjustments) which are due and payable based on the revised shipping date and contract price are equal to or greater than the payments already made. The revised shipping date will be based on appropriate considerations including, but not limited to, Westinghouse's commitments to other customers, engineering work load, and the availability of labor, materials and manufacturing space.

At any time prior to twelve months from the previously scheduled shipping date Purchaser may by written notice to Westinghouse request suspension of manufacture of all or part of the equipment. If Westinghouse agrees to the suspension, Purchaser shall pay to Westinghouse, within fifteen days of notice to Purchaser of acceptance of the suspension, the difference

① Changed or added since previous issue.

Westinghouse Electric Corporation
Steam Turbine Division, Philadelphia, Pa. 19113
Printed in USA

Westinghouse

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between the value of the work performed (based upon the contract price, as adjusted by the Selling Policy, and percentage completion) and the sum of the payments made prior to the date of acceptance of the suspension. When suspension is accepted by Westinghouse further payments under the Terms of Payment will be discontinued until the Purchaser requests Westinghouse to resume work. Prior to resumption of work the contract price shall be increased to reflect the costs resulting from the suspension. With the establishment of a revised shipping date and contract price a new payment schedule will be determined assuming that the revised shipping date and contract price had been in effect from the date of Written Release. Purchaser will resume payments when the cumulative payments (including price adjustments) which are due and payable based on the revised shipping date and contract price are equal to or greater than the payments already made. The payment which is due on the 15th day of the month following resumption of work will, if necessary, be increased to make the total amount paid and due by said 15th day equal to the total payments (including adjustments in accordance with the Selling Policy) required by the new payment schedule. When Purchaser directs Westinghouse to resume work the revised shipping date will be established based on appropriate considerations including, but not limited to, Westinghouse's commitments to other customers, engineering work load and the availability of labor, materials and manufacturing space.

If as a result of extension or suspension the revised shipping date is later than the date which qualifies the unit covered by the contract for the Selling Policy contained in the contract, then the price shall be determined by the Selling Policy which first becomes effective for such shipment.

Within 12 months of the scheduled shipping date, extension of the shipping date or suspension of manufacture is not permitted and payments will continue on the basis of the previously established shipping date. Westinghouse will continue manufacture of the equipment and when completed will ship the equipment to the Purchaser or to a suitable storage location selected by Purchaser. Purchaser shall reimburse Westinghouse for any additional expenses incurred by Westinghouse including but not limited to preparation for placement into storage, inspection, shipment to the Purchaser's storage site and any necessary rehabilitation prior to installation.

①Written Release

Unless otherwise agreed upon by Purchaser and Westinghouse, the Purchaser shall by written notice to Westinghouse release each Turbine Generator for engineering and manufacture not later than 30 months prior to its scheduled shipping date.

①Title

For the purpose of title passage, legal and equitable title to each component or item of equipment shall pass upon transfer of component or item to the carrier at the point of shipment.

①Risk of Loss

Risk of loss or damage for each component or item of the equipment shall pass to Purchaser upon arrival of each component or item of the equipment on board the common carrier (a) at the railsiding nearest the Purchaser's plant site for equipment shipped by rail and (b) at the Purchaser's plant site for equipment shipped by truck.

①Transportation

Shipment will be made f.o.b. point of shipment, freight (not exceeding regular charges of the normally selected common carrier) prepaid and included in the price (including trucking at the option of Westinghouse) to: (1) rail siding nearest to the installation site or; (2) if the installation site is outside the United States or is in Alaska or Hawaii, to the rail siding nearest to the point of commencement of overseas shipment. Any charges resulting from the use of a method or routing required by the Purchaser and not normally selected by Westinghouse and any charges for special services (such as, but not necessarily limited to special trucking, special trains, barging, lighterage, or construction or repair of transportation facilities) will be paid or reimbursed by the Purchaser.

①Delay

Shipping dates are based on prompt receipt of all necessary information and approvals from the Purchaser. Westinghouse shall not be liable for failure to perform or for delay in performance due to fire, flood, strike or other labor difficulty, act of any governmental authority or of the Purchaser, riot, embargo, car shortage, wrecks or delay in transportation, inability beyond its control to obtain necessary materials, or manufacturing facilities from usual sources, or due to any other causes beyond the reasonable control of Westinghouse, its suppliers and subcontractors, of any tier.

In the event of delay in performance due to any such cause, the date of delivery or time for completion will be postponed by such length of time as may be reasonably necessary to compensate for the delay.

In the event of any delay due to causes beyond the control of Westinghouse, its suppliers and subcontractors, of any tier, such as those contained in the above paragraph, or to any causes within the reasonable control of Westinghouse, its suppliers and subcontractors, of any tier, all payments made thereafter shall be paid and adjusted in accordance with the new shipping date.

①Warranties

A. Equipment

Westinghouse warrants that the equipment to be provided will conform to all specifications (including those relating to performance) which are part of the contract, will be free of defects in workmanship or material, and will be designed and fit for the purpose of generating electric power.

If any failure to conform to the foregoing warranties appears before twelve months after the date of initial synchronization (provided synchronization is not unreasonably delayed by the Purchaser or others) and Purchaser gives Westinghouse prompt written notice of such non-conformity and makes the apparatus available for correction, then Westinghouse shall correct such nonconformity by suitable repair or replacement at the option of Westinghouse and at its expense. The cost of field labor directly associated with such repair or replacement of the equipment provided under the contract shall be borne by Westinghouse. This obligation for field labor is limited to the equipment provided under the contract and does not include the cost of removing or replacing parts, equipment and/or structures not furnished under the contract.

B. Technical Direction of Installation

Westinghouse warrants that the Technical Direction of Installation to be provided hereunder for installation of the equipment will be competent and non-negligent.

If any portion of the equipment furnished under the contract is damaged as a direct result of incompetent or negligent Technical Direction of Installation before twelve months after the date of initial synchronization (provided synchronization is not unreasonably delayed by the Purchaser or others) and Purchaser gives Westinghouse prompt written notice of such damage before twelve (12) months after the date of initial synchronization and makes the equip-

① Changed since previous issue.

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ment available for correction, then Westinghouse shall repair or replace at its option and expense any portion of the equipment furnished under the contract that has been so damaged. The cost of field labor directly associated with such repair or replacement of the equipment furnished under the contract shall be borne by Westinghouse. This obligation for field labor is limited to the equipment supplied under the contract and does not include the cost of removing or replacing parts, equipment and/or structures not furnished under the contract.

In no event shall Westinghouse be responsible for any damage caused, in whole or in part by (a) Purchaser, its employees, contractors, or their employees, agents, or subcontractors, (b) failure to observe Westinghouse's field representatives' instructions, (c) failure or malfunctioning of any tools, equipment, facilities, or devices not provided by Westinghouse, or (d) the failure of equipment, the installation of which was not observed or approved by the Westinghouse field representative.

C. Conditions

The following conditions apply to both the Equipment and Technical Direction of Installation Warranties:

1. Westinghouse will not be responsible for any failures to conform to the warranties detailed herein that are caused by failure of the Purchaser or his agents to store, install, operate, inspect or maintain the equipment in accordance with the recommendations of Westinghouse, (including the applicable quality assurance requirements for installation), and with recognized industry practice.

2. If prior to the expiration of the above stated warranty period, the equipment is not available for operation due to a failure to meet the warranties, such time of unavailability shall not be counted as part of the warranty period. Provided, however, that Westinghouse shall not be responsible for any failure to conform to these warranties which appears more than eighteen months after the date of initial synchronization.

3. The warranty on repaired or replaced parts will be on the same terms and conditions as set forth above and will extend from the date of such repair or replacement.

4. **The foregoing warranties are exclusive and in lieu of all other warranties of quality whether statutory, express, or implied (including any warranty of merchantability or fitness for purpose).** Correction of nonconformities in the manner and for the period of time provided above shall constitute Westinghouse's sole liability, and the Purchaser's exclusive remedy for failure of Westinghouse to meet its warranty obligations whether claims of the Purchaser are based in contract, in tort, or otherwise.

①Limitation of Liability

Neither Westinghouse nor its suppliers or subcontractors, of any tier, shall be liable in contract, in tort (including negligence), or otherwise, for damage or loss of other property or equipment, loss of profits or revenue, loss of use of power system, expenses involving costs of capital, cost of purchased or replacement power (including additional expenses incurred in using existing power facilities), claims of customers of Purchaser for service interruptions, or any special, indirect, incidental, or consequential damages.

The remedies of the Purchaser set forth herein are exclusive, and the total liability of Westinghouse with respect to any contract, or anything done in connection therewith such as the performance or breach thereof, or from the manufacture, sale, delivery, installation or technical direction of installation, repair or use of any equipment covered by or furnished under the contract whether in contract, in tort (including negligence), or otherwise, shall not, except as provided under the Warranty and Patents clauses, exceed the amount of the billing price of the unit out of which the liability arises; provided however that the sole liability of Westinghouse for claims involving defective or damaged equipment furnished under the contract, will be the correction of such defect or damage but in no event, except as provided under the Warranty clause, shall the correction exceed the amount of the billing price of the unit out of which the liability arises. All liability of Westinghouse shall, in any event, terminate four years after initial synchronization of the equipment.

Patents

Subject to the following provisions, Westinghouse shall at its own expense, defend or at its option settle any claim, suit or proceeding brought against the Purchaser, and/or its vendees, mediate and immediate, so far as based on an allegation that any goods, material, equipment, device or article (hereinafter referred to as product) or any part thereof furnished hereunder constitutes a direct or a contributory infringement of any claim of any patent of the United States. This obligation shall be effective only if Purchaser shall have made all payments then due hereunder and if Westinghouse is notified promptly in writing and given authority, information and assistance for the defense of said claim, suit or proceeding. Westinghouse shall pay all damages and costs awarded in such suit or proceedings so defended. In case the product or any part thereof furnished hereunder becomes the subject of any claim, suit or proceeding for infringement of any United States patent, or in the event of an adjudication that such product or part infringes any United States patent, or if the use or sale of such product or part is enjoined, Westinghouse shall, at its option and its own expense, either:

(a) procure for the Purchaser the right to continue using said product or part thereof; or

(b) replace it with a non-infringing product; or

(c) modify it so it becomes non-infringing.

The foregoing indemnity does not apply to the following:

1. Patented processes performed by the product, or another product produced thereby.

2. Products supplied according to a design other than that of Westinghouse and which is required by the Purchaser.

3. Combinations of the product with another product not furnished hereunder unless Westinghouse is a contributory infringer.

4. Any settlements of a suit or proceeding made without Westinghouse's written consent.

The foregoing states the entire liability of Westinghouse with respect of patent infringement by said product or any part thereof.

If a suit or proceeding is brought against Westinghouse solely on account of activities enumerated in paragraphs 1, 2 and 3 above, Purchaser agrees to indemnify Westinghouse in the manner and to the extent Westinghouse indemnified Purchaser in the preceding paragraph insofar as the terms thereof are appropriate.

①Termination

Any contract may be terminated by the Purchaser only on written notice and upon payment of reasonable and proper termination charges. Payments received by West-

① Changed since previous issue.

Conditions of Sale, Continued

inghouse prior to the date of termination will be credited to the amount due as termination charges.

Any such termination occuring prior to the date of Written Release will be without charge provided the planned generation expansion which would utilize the equipment covered by the contract, be abandoned or cancelled.

①Acceptance Tests

If tests are made after erection to demonstrate the ability of the unit to operate under the contract conditions and fulfill the warranties set forth herein, the conditions of test and methods employed will be mutually agreed upon within the framework of the ASME power test code.

Westinghouse will be notified and will have the right of representation at the acceptance tests. To insure the equipment being in proper adjustment and in condition to undergo tests, Westinghouse may require preliminary tests made under Westinghouse's general direction.

①Price Itemization

When prices are quoted for a turbine generator unit along with other power plant or system equipment, the price and terms of payment for the turbine generator including accessories will be listed separately.

①Changes

The Purchaser may request changes in the unit type, rating or steam conditions or in the accessory items being purchased hereunder. Westinghouse reserves the right to accept or reject any such change but shall exert every reasonable effort to comply with the requests of the Purchaser. The prices and conditions of sale for such changes and accessories will be established on the same basis as the turbine generator contract. Provided however that should such a request be made after release by Purchaser for engineering, Westinghouse reserves the right to require an additional increase in the contract price to reflect the expenses of re-engineering and manufacturing re-work, and to adjust other appropriate provisions of the contract.

The prices for the equipment supplied under the contract are based upon the Westinghouse design criteria and manufacturing processes in effect as of the date of the bid. Should the Purchaser require changes in the Westinghouse design criteria and/or manufacturing processes to meet requirements established by the Purchaser or by any federal, state or local governmental agency, the price, shipment and other conditions of sale will be adjusted accordingly.

①Compliance with Laws

The Contract price is based on designing and manufacturing the equipment supplied under the contract in accordance with Westinghouse design criteria, manufacturing processes and quality assurance programs in effect on the date of the bid, and in compliance with all applicable Federal laws, rules and regulations thereof in effect on the date of the bid. Unless otherwise stated in the contract, the contract price is based on compliance with those provisions of State and local laws, rules and regulations thereof which were, prior to the date of the bid, identified in writing by the Purchaser as applicable to the equipment or services to be furnished under the contract.

In the event that: (a) Federal laws, rules and regulations enacted and/or effectuated after the date of the bid, (b) revisions to and revised interpretations of Federal laws in effect as of the date of the bid, (c) State and local laws, rules and regulations (unless otherwise noted in this article); require changes in the equipment or quality assurance programs, then the price will be equitably adjusted to reflect the added expense incurred by Westinghouse as a result of such change(s) and other appropriate provisions of the contract, including but not limited to the shipping date, will be equitably adjusted. Furthermore where the requirements of (a), (b) or (c) above require changes in the equipment or quality assurance program(s) and these in turn necessitate changes in the Westinghouse design criteria and/or manufacturing processes, then, the price will be equitably adjusted to reflect the added expense incurred by Westinghouse as a result of such change(s) and other appropriate provisions of the contract, including but not limited to the shipping date, will be equitably adjusted.

Purchaser will provide Westinghouse with written advice as to those State and local laws, rules and regulations which are applicable to the equipment or services to be furnished under the contract. In the event that State and local laws, rules and regulations thereto necessitate changes in the equipment which Westinghouse can not reasonably incorporate in its design, then the Purchaser has the option to either terminate the contract in accordance with the Termination provisions or to direct Westinghouse to complete the equipment without change with Purchaser assuming responsibility for obtaining all necessary waivers.

As used in this article the term State and local means the State and locality in which the equipment is to be installed and the State whose law governs the contract.

Inspection by Purchaser

The Purchaser shall have reasonable access to the areas of the Westinghouse plant where his work is being manufactured and tested for purposes of observing and witnessing such operations. Westinghouse will advise the Purchaser of the scheduled date(s) to perform the test(s) which Purchaser has specifically indicated a desire to witness; however, no rescheduling of tests nor delays in manufacturing or shipment will be made to accommodate such inspection.

Westinghouse will exercise every reasonable effort to secure similar rights with respect to the inspection by Purchaser of work at supplier's and subcontractor's premises.

①Technical Direction of Installation

1 Westinghouse shall, as specified below, furnish the services of one or more field engineers as deemed necessary by Westinghouse, to give technical direction to the Purchaser regarding methods and procedures for the installation of the equipment covered by the contract; to direct the Purchaser's representatives in making such operating tests as are specified in the contract; and to instruct the Purchaser's operating personnel in the recommended procedures for starting, operating, and shutting down the equipment. As used herein, "Technical Direction of Installation" is defined as follows:

   Technical Direction of Installation is the engineering and technical guidance, and counsel based upon current engineering, manufacturing, installation and operating standards for the Westinghouse equipment. Technical Direction excludes any supervision, management, regulation, arbitration and/or measurement of Purchaser's personnel, agents or contractors and work related thereto, and it does not include responsibility for planning, scheduling, monitoring, or management of the work.

   Westinghouse will provide full time technical direction for the period defined below to direct the following activities:

   a Transverse anchor blocks and soleplate setting;
   b Unloading and transferring the major components from rail cars, trucks or vessel to the foundation;
   c Installation and assembly of the equipment on foundation;
   d Starting the equipment and placing it in good operating condition.

① Changed since previous issue.

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The Field Engineer shall also perform the following services:

a Confer with Purchaser's installation personnel regarding equipment, plans, objectives and procedures;

b Inspect the major parts as to assembly, clearances, alignment and cleanliness;

c Coordinate shipment of parts from the factory to minimize delays in transit;

d Observe work practices and procedures of Purchaser's installation personnel to assure that factory-recommended quality assurance installation procedures are not violated;

e Provide estimates of time requirements for accomplishment of work;

f See that the necessary prints and instructions are provided to accomplish planned installation.

Westinghouse shall furnish special erecting tools and instruments it deems necessary.

2 The Purchaser shall furnish all labor, superintendence, materials, and equipment and shall do everything not specifically set forth above, necessary for the installation of the equipment. The Purchaser shall, without limitation, provide:

a Adequate unloading and storage facilities;

b Foundations with foundation bolts, grouting forms, grouting and labor for pouring same, conduits, cables, and cable supports;

c Reinforcement of floors, overhead protection from the elements and otherwise, and such modifications in Purchaser's buildings or premises as are necessary for the proper erecting of the equipment;

d Electric power and equipment to dry out the equipment;

e Interconnecting wiring and installation labor;

f Painting and all external steam, oil, and water piping not furnished as an integral part of the equipment;

g Operating force, steam, oil, instruments, and supplies for starting and preliminary run;

h All necessary labor for installation, including inspection and superintendence.

Purchaser shall notify Westinghouse when the first major alignment part of the equipment has arrived at the carrier's delivery point. The Purchaser shall consult the Field Engineer before scheduling any installation work and shall afford the Field Engineer reasonable opportunity to perform the services specified herein during his regular working hours.

3 a The period of Technical Direction of Installation at the site shall commence on the date agreed upon by the parties for setting foundation hardware and, except for the times during which no installation work on the equipment is scheduled or performed by the Purchaser, shall continue until the date upon which Westinghouse gives the Purchaser notice that the technical direction, inspection and instruction is complete.

b The price quoted includes technical direction services on straight time, during the first 8 hours of each shift, 5 days per week, Monday through Friday.

c In the event the Purchaser interrupts, extends, or accelerates the work, so as to require technical direction service at times other than provided in (b) above, Westinghouse reserves the right to render additional billing as follows:

1) If the work schedule goes to overtime for the purpose of accelerating the work, the overtime billing due Westinghouse will be the premium portion of Westinghouse's published rates in effect at the time the work is performed.

2) If the work schedule is interrupted, or extended, or if other services of the field representative are required not specifically provided for herein such as, but not limited to, using special equipment when handling the turbine generator during transit, storage, or installation, or when the service is required during delays caused by the Purchaser or others, or when the service is required during periods when work on the equipment is being performed by a labor force of less than adequate size and composition, services will be billed at Westinghouse's current rates in effect at time the work is performed.

4 Westinghouse shall indemnify and save harmless the Purchaser for, but only for, (a) all actions, suits, liability, and claims for non-nuclear damage to property(ies) of third parties located at Purchaser's power plant site which occur during, and result directly and solely from the negligence of the employees of Westinghouse in, the performance of Technical Direction of Installation on the premises of the Purchaser; and (b) all actions, suits, liability, and claims for non-nuclear injury to persons, including death, which occur during, and result directly and solely from the negligence of the employees of Westinghouse in, the performance of Technical Direction of Installation on the premises of the Purchaser.

General

These standard conditions of sale are issued for the information of prospective Purchasers and are not intended as an offer. All offers or quotations on behalf of Westinghouse for the sale of the equipment described herein will be prepared by its Steam Turbine Division, Lester, Pennsylvania. No amendments, modifications, or attempted waivers of the provisions set forth herein shall be binding on either party unless set forth in writing and signed by authorized representatives of both parties.

When requested by Purchaser, Westinghouse may supply Digital Electro-Hydraulic control documents and tapes which contain proprietary information. A program protection agreement must be executed before available program listings can be submitted to the Purchaser.

The equipment covered in this price list is not designed primarily for use in nuclear power plants. In the event the equipment is to be used with steam from a nuclear source, it is necessary that such intent be declared at the time of the inquiry. In such event the clauses entitled Warranty, Technical Direction of Installation, and Insurance – Nuclear Indemnity from Price List 1262 will be incorporated in the contract.

If the equipment is used in, with, at, or near to a nuclear installation without notification to Westinghouse and its written consent thereto, Westinghouse disclaims all responsibility of every kind, including negligence, and, in addition, the Purchaser shall indemnify and hold harmless Westinghouse, its suppliers and subcontractors, of any tier, from any liability or damage whatsoever arising out of the equipment.

①Westinghouse certifies that the equipment to be provided and services to be performed under the contract will be provided in accordance with the provisions of the Fair Labor Standards Act of 1938, as amended.

Any assignment or transferral of the contract or any rights herein shall be made only with the written consent of Westinghouse.

Should any of the foregoing conditions of sale be held invalid, such condition shall be considered severable and such invalidity shall not affect the remainder of the conditions herein.

① Changed since previous issue.

Westinghouse Electric Corporation
Steam Turbine Division, Philadelphia, Pa. 19113
Printed in USA

Westinghouse

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

General Information

Negotiation Data

Delay can be avoided and better service given if complete information is sent in with the original inquiry. Therefore, requests for quotations should give full information for each of the following points:

1 Turbine rating, kw – (see page 6).
2 Steam conditions:
  a Initial steam pressure, psig.
  b Initial steam temperature, F.
  c Reheat steam temperature, F.
  d Exhaust pressure, inches of Hg abs. normal and maximum.
  e Number of extraction openings required.
  f Quantity and type of steam to be extracted for purposes other than feedwater heating.
  g Final feedwater temperature.
3 Type designation: TC2F, TC4F, CC4F, etc.
4 Exhaust blade length, inches.
5 Speed, rpm.
6 Generator rating, kva.
7 Power factor.
8 Generator phase, frequency.
9 Short-circuit ratio.
10 Excitation speed of response ratio.
11 Type of boiler feed pump drive and pump efficiency data.
12 List all optional accessories and special requirements desired by Purchaser, such as heater out of service, overpressure, etc.

Erection Service

Prices for erection services are not listed in this price list. Such services will not be quoted with the unit, but will be quoted when unit size and configuration have been finalized and when major drawings have been issued by Westinghouse and approved by Purchaser.

Refer such inquiries to Power Generation Service Division, Marketing Department.

Basis of Prices

The tabulated prices include a complete turbine generator unit consisting of a steam turbine, an electric generator, an excitation system, and standard features and accessories as listed herein, including technical direction of installation.

Seismic Considerations

Neither the standard nor the special accessories include seismic restraints for turbine generator apparatus. Such restraints, where required, are to be supplied by the Purchaser and suitable attachment provisions will be made where feasible and necessary.

No changes since previous issue.

Prices effective October 30, 1974: subject to change without notice.

October 30, 1974
Supersedes Price List 1252, dated July 1, 1974
E, C/1683/PL

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Steam Turbines

Turbine Rating

Turbine ratings listed in this publication are the maximum guaranteed turbine kilowatts at 3.5" Hg absolute exhaust pressure with 3% makeup.

Price of unit will be based on the maximum guaranteed output of the unit at 3.5" Hg absolute, 3% makeup with the highest initial steam conditions for which the machine is guaranteed. Accessories will be priced at this maximum guaranteed output.

Throttle Flow

Each unit, in order to provide for manufacturing tolerances, will be designed with 5% flow margin above the flow required to meet the maximum guaranteed output.

Overpressure

Each unit will be safe for continuous operation at 105% of the rated pressure with the governing valves wide open when operated in accordance with the parameters shown on the maximum calculated 5% overpressure heat balance. Should a unit be desired that is safe for continuous operation at a pressure higher than 105% of rated pressure, the unit will have a guaranteed output at a pressure 5% lower than the specified pressure and a 5% flow margin will be designed into the unit above that flow necessary to meet this guaranteed output.

Extractions

Openings are provided in each turbine for steam extraction required for the usual feed heating cycle, for up to 6% of the throttle-flow at maximum guaranteed output for uncontrolled extraction such as air heating when specified, and to heat 3% makeup. Should a unit be required to provide additional extraction flow, for purposes such as uncontrolled extraction above 6%, boiler feed pump turbine drives, and to heat more than 3% makeup, the extraction must be considered in the design, and a price addition will be required.

①Feedwater Heater Extractions

Should the Purchaser desire to remove one or more feedwater heaters from service to obtain additional capability beyond the guaranteed capability obtained with all heaters in service, this increase in capability at 3.5" Hg absolute and 3% makeup will be guaranteed and priced at the incremental price in dollars/kw set forth elsewhere in this publication.

For emergency operation, heaters may be removed from service. Such emergency operation with heaters out of service will be governed by the following rules provided the Exhaust Loading Limits are not exceeded:

1 If the turbine output is adjusted such that it does not exceed the maximum guaranteed output: (a) one or more non-adjacent heaters may be removed from service or (b) adjacent heaters may be removed if all higher pressure heaters also are removed from service.

2 Should the Purchaser desire to remove adjacent lower pressure heaters from service while higher pressure heater(s) remain in service, the load must be reduced by adjusting throttle flow such that there is at least a 10% reduction from maximum guaranteed load for each successive adjacent heater removed from service. For example, if two lower pressure adjacent heaters are removed while a higher pressure heater remains in service, the load must be reduced 10%. If three adjacent heaters are removed, the load must be reduced 20%, etc. The maximum load reduction necessary is 50% for any combination of heaters out of service.

If the Purchaser desires to maintain the maximum guaranteed load with two or more adjacent lower heaters out of service while a higher pressure heater remains in service, a price addition will be made for the kilowatt load in excess of those outlined above.

Operation with heaters out of service with unusual arrangements or multiple strings of heaters must be analyzed to determine the necessary load reductions to assure that the loading of the unit parts will not exceed that under normal operation with all extractions in full normal operation.

For unusual cycles or heater arrangements, refer to Steam Turbine Division, Marketing Department.

Uncontrolled Extractions

Uncontrolled extraction steam may be required by the Purchaser. This extraction steam flow may be separated into two types as follows:

1 Seasonally variable flow such as that required to preheat the air to a temperature warm enough to prevent air preheater corrosion or preheat the air to a summer ambient. This flow shall be assumed to be shut off in the determination of maximum turbine exhaust flow, as defined in exhaust loading limits.

2 Continuous flow such as that required to increase the combustion air from the ambient temperature to a higher required inlet temperature. This extraction flow, since it is continuous, will not pass through the last row of blades under normal operating conditions. This flow is not assumed to be shut off in the determination of maximum turbine exhaust flow.

The turbine may be operated for emergency periods with the continuous extraction steam flow shut off providing that the control valves are adjusted so that the turbine does not exceed either the maximum guaranteed output or the maximum exhaust loading limits.

The total of all uncontrolled extraction flows, including seasonal and variable, shall not exceed 12% of the throttle flow at maximum guaranteed output.

The turbine may be operated for emergency periods with the continuous steam flow reduced provided the control valves are adjusted such that the load on the turbine is reduced in kilowatts by an amount equal to the per cent reduction in the continuous steam times the difference between the maximum calculated 5% overpressure capability and the maximum guaranteed output. The turbine must also not exceed the maximum exhaust loading limits.

Makeup and Exhaust Pressure②

Should a machine be specified with a maximum guaranteed output at exhaust and makeup conditions other than 3.5" Hg absolute and 3% makeup, the rating will be corrected to a 3.5" Hg exhaust, 3% makeup basis for pricing by use of the following formula:

Specified maximum guaranteed output times (1 – A – B) = pricing rating at 3.5" Hg absolute – 3% makeup, where A and B are correction factors for exhaust pressure and makeup from the following table:

Corrections for Exhaust Pressure

Exhaust Pressure (In. Hg Abs.)	A
4.5	–0.020
4.0	–0.010
3.5	0
3.0	0.005
2.5	0.010
2.0	0.015
1.5	0.020
1.0 and 0.5	0.025

Corrections for Makeup

Makeup (percent)	B
3.0	0
2.0	0.003
1.0	0.006
0	0.009

The turbines are suitable for operation at back pressures up to 5.5" Hg absolute. For units to operate at high back pressures, Purchaser must either purchase auxiliaries suitable for use with higher cooling water temperatures, if available, or find another source of cooling water other than condensate. The standard coolers are designed for 95 F cooling water and the standard gland condensers are designed for 125 F cooling water. See the pricing tables D and E for available oversize coolers and gland condensers.

① Changed since previous issue.
② For high back pressure units, see Page 18.

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Westinghouse

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Steam Turbines, Continued

Automatic Extraction Machines

An automatic extraction turbine as opposed to a non-automatic unit, will include all of the features and accessories included with a non-automatic unit as well as:

Automatic extraction equipment to control the pressure of the extracted steam by varying the flow of steam to the lower pressure turbine stages.

Necessary inter-connections between the turbine governing system and the extraction control equipment.

Automatic non-return valves with trip actuated by the turbine overspeed device, for each automatic extraction opening.

For details and prices, refer to Steam Turbine Division Marketing Department.

Allowable Steam Pressure and Temperature Variations

The turbine rating, capability, steam flow, speed regulation and pressure control are based on operation at rated steam conditions. The turbine generator unit is capable of operation under the following variations in steam pressure and temperature. These allowable variations a[illegible] intended to provide for operating exiger[illegible] and it is expected that such abnormal operation will be kept to a minimum, especially the occurrence of simultaneous variations in pressures and temperatures.

Inlet Pressure

The pressure at the turbine throttle valve inlet connection shall be controlled to maintain an average operating pressure of not more than 105% of rated pressure. In maintaining this average over a 12-month operating period, the pressure shall not exceed 105% of rated pressure by more than 1% for periods of time no longer than reasonably required for control. During abnormal conditions, the peak of pressure swings at the inlet shall not exceed rated pressure by more than 30%. The aggregate duration of all such momentary swings above 105% of rated pressure shall not exceed a total of 12 hours per 12-month operating period.

Such momentary swings are conditional upon the control valves being adjusted such that the turbine flow does not exceed the steam flow obtained by operating at 105% rated pressure with control valves wide open.

Reheat Pressure

The pressure at the exhaust connection of the high pressure turbine shall not be greater than 25% above the highest pressure existing when the high pressure section of the turbine is passing the maximum calculated flow with 105% rated pressure and normal operating conditions. Suitable relief valves must be provided by the Purchaser.

Inlet Temperature

The steam temperature at the turbine throttle valve inlet connection shall average not more than rated temperature over any 12-month operating period. In maintaining this average the temperature shall not exceed rated temperature by more than 15 F.

During abnormal operating conditions the temperature at the turbine throttle valve inlet connection shall not exceed rated temperature by more than 25 F for operating periods not more than 400 hours per 12-month operating period, nor rated temperature by more than 50 F for swings of 15 minutes duration or less aggregating not more than 80 hours per 12-month operating period.

In maintaining the temperatures specified in the preceding paragraphs the steam delivered through any turbine main inlet valve must be within 25 F of the steam delivered simultaneously through any other main inlet valve. During abnormal conditions this difference may be as high as 75 F for periods of 15 minutes maximum duration providing such occurrences are at least four hours apart.

Reheat Temperature

The steam temperature at the turbine reheat admission shall average not more than rated reheat temperature over any 12-month operating period. In maintaining this average the reheat temperature shall not exceed rated reheat temperature by more than 15 F.

During abnormal conditions reheat temperature shall not exceed rated reheat temperature by more than 25 F for operating periods totalling not more than 400 hours per 12-month operating period, nor rated reheat temperature by more than 50 F for swings of 15 minutes duration or less, aggregating not more than 80 hours per 12-month operating period.

In maintaining the above reheat temperature averages the steam delivered through any hot reheat inlet zones in the turbine must be within 25 F of the steam delivered simultaneously through any other hot reheat zone. During abnormal conditions this difference can be as high as 75 F for periods of 15 minutes maximum duration providing the occurrences are at least four hours apart.

①Factory Tests Performed on Turbines

The following tests normally will be made by Westinghouse at the factory prior to shipment:

Governor component tests
Valve and steam chest servomechanism tests
Turning gear assembly operation
Mechanical balance of rotor
Tests to insure thermal stability of rotor
Rotor overspeed

The individual turbine sections will be assembled as required by Westinghouse to establish and verify the operating clearances.

Exhaust Loading Limits

Loading of last row blades will be permitted up to the exhaust flows tabulated below.

The flows shown are to be obtained at 3½" Hg abs, 0% make-up and at the operating conditions which impose the most severe condition at the exhaust. These conditions include valves wide open, maximum permissible initial pressure for safe continuous operation, heaters out of service when applicable and seasonal variations in air preheating requirements etc. Continuous normal air preheating steam will not be considered in determining the maximum permissible exhaust flow since when this extraction is shut off, throttle flow must be reduced such that the load does not exceed the maximum guaranteed load.

Last Stage Blade Length Inches	Rpm	Exhaust Flow #/Hr/Last Row
25	3600	616,000
28.5	3600	805,000
31	3600	992,000
40	1800	1,585,000
44	1800	1,857,000
52	1800	2,586,000

① Deletion since previous issue.

Prices effective October 30, 1974; subject to change without notice.

October 30, 1974
Supersedes Price List 1252, dated July 1, 1974
E, C/1683/PL

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Steam Turbines, Continued

Standard Features and Accessories

1 Control and protective valve systems, including the following:

A Separate mounted steam chests with stop-throttle valves and governing control valves, each including:
1) Servo-actuator.
2) Nine (9) switch contacts for each stop-throttle valve.
3) Removable temporary fine mesh and permanent heavy mesh strainers for each stop-throttle valve.

B Flexible inlet piping between the steam chests and turbine casing.

C Reheat stop valves and interceptor valves, each including:
1) Actuator.
2) Nine (9) switch contacts.
3) Removable temporary fine mesh and permanent heavy mesh strainers for interceptor valves only.

D Piping from interceptor valves to the intermediate pressure turbine (when required).

E High-speed synchronizing equipment for cross-compound units. Includes stop and control valves, valve hangers (excluding supporting steel), steam piping, oil piping, differential speed indicator and crossover temperature alarm.

2 Electrohydraulic control system, including:②

A High pressure (1,800 psig nominal) hydraulic fluid system consisting of:
1) Fluid reservoir with separate fluid charging unit (fluid not included).
2) Fluid supply system mounted on the reservoir and consisting of:
a) Two a-c motor-driven positive displacement pumps. (Motors are totally enclosed.)
b) One suction and four discharge filters.
c) Two pressure switches for sensing drop across discharge filters.
d) Two unloading valves.
e) Relief valve.
f) Two check valves.
g) Drain system pressure switch.
h) Two coolers.
i) Two polishing return line filters.
j) Bypass check valve.
k) Fuller's earth fluid conditioning unit.
l) Level gauge.
m) Dial thermometer.
n) Two "pump running" pressure gauges.
o) Header pressure gauge
p) Header pressure transmitter.
q) Magnetic plug assembly.
r) Hydraulic fluid thermocouple.
3) Hydraulic accumulators, gas charged. (Gas not included.)
4) Suitable interlocks and alarms as follows:
a) Automatic start of second pump on low fluid pressure.
b) Low high-level switch for alarm.
c) Low low-level switch for alarm and trip.
5) Terminal box for:
a) Pressure switches.
b) Terminal block for electrical connections.
c) Phone jack.
6) All interconnecting piping between the H.P. fluid supply system and the actuators. Stainless steel tubing and manifolds will be used where applicable.
7) Emergency trip valve.
8) Emergency trip solenoid valve.
9) Two auxiliary governor solenoid valves.
10) Fluid transfer pump.

B Solid state digital controller, including:
1) Throttle valve controller consisting of:
a) Automatic wide range speed control to enable the operator to preset the desired speed and rate of speed increase.
b) Manual control from operator's panel.
c) Tracking device for transfer from operator automatic to manual control together with the necessary switches.
d) Bumpless transfer from operator automatic to manual, or manual to operator automatic.
e) Servo amplifiers for throttle valves.
2) Governor valve controller consisting of:
a) Automatic load and speed control.
b) Manual control from operator's panel.
c) Tracking devices to permit manual control to back-up operator automatic control.
d) Bumpless transfer from operator automatic to manual, manual to operator automatic, impulse pressure "out" mode to "in" mode and impulse pressure "in" mode to "out" mode.
e) Servo amplifiers for governing valves.
3) Valve position limit control from operator's panel.
4) Overspeed protection controller to close valves in response to a mismatch between unit output versus turbine internal pressure and turbine overspeed. (Includes provision to test.)
5) Throttle pressure regulator control consisting of:
a) Pressure transducer.
b) Pressure controller.
c) Adjustable pressure set point.
6) Speed control consisting of:
a) Speed transducer (two magnetic pickups plus one spare on one pulse wheel).
b) Main speed computing channel.
c) Auxiliary speed computing channel.
d) Reference channel with set point and rate control.

NOTE: Digital speed reference system can be used for speed matching control of turbine-generator unit to line frequency.

7) Load control
a) Impulse chamber pressure transducer.
b) Pressure control channel.
c) Reference channel for on-line load control with adjustable set point and rate control.
d) Megawatt feedback for slow trim of load control.
8) Transfer control to change throttle valve full admission operation to governor valve partial arc admission operation.
9) Valve management (when applicable) for operator initiated automatic change of governing control valve sequencing while under load.
10) Interface provisions for Purchaser's automatic load dispatch, load

Deletion since previous issue.
② The digital E-H control system is described. An analog system can be furnished for no price addition in lieu of the digital system. For other control systems, refer to the Large Turbine Division, Marketing Department.

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Steam Turbines, Continued
Standard Features and Accessories, Continued

frequency control, or coordinated boiler control. (Inputs consisting of raise-lower contacts, and analog outputs consisting of frequency bias and load reference.)

11) Automatic acceleration program, capable of directing the acceleration of the unit from turning gear to synchronous speed, while monitoring HP turbine rotor stress, steam, oil and metal temperatures, steam pressures, unit vibration, thermal expansion and generator temperatures and hydrogen pressures. Included are necessary sensors, computer hardware and software.

12) Automatic loading program, capable of directing the increase and decrease in load of the unit between minimum load and the load corresponding to valves wide open, while monitoring HP turbine rotor stress, steam, oil and metal temperatures, steam pressures, unit vibration, thermal expansion and generator temperatures and hydrogen pressures. Also included is the ability to provide a continuous indication of the load increase or decrease capability of the unit. Included are necessary sensors, computer hardware and software.

13) Logout program to indicate the value of up to 19 variables at a frequency of up to every 60 seconds on the typewriter. Sensors and input/output equipment included only if provided by Westinghouse under items 2B11 and 12 above.

14) Indication of the optimum range of control valve positions during sequential valve operation.

15) Alarms and selected operator instructions printed out on the typewriter.

16) "At load" and" Load changing" contacts for Purchaser's use when required.

C Paper tape reader.

D Operator's panel (three sections), consisting of:

1) Control panel (upper)
   a) Indicating meters for shaft speed and electrical load.
   b) Throttle valves additive position meter.
   c) Governor valves additive position meter.
   d) Indicating lights for:
      1 Turbine trip.
      2 Runback operation.
      3 Controller speed channel monitor.
      4 Overspeed protection controller speed channel monitor.
      5 Megawatt transducer monitor.
      6 Overspeed protection controller pressure transducer monitor.
      7 Overspeed protection controller monitor.
      8 Impulse pressure transducer monitor.
      9 Emergency power supply.
      10 Transfer relay, 24 volts, monitor.
      11 Controller off.
      12 Throttle pressure transducer monitor.
      13 Throttle pressure limiting.

2) Control panel (lower)
   a) Numeric in-line display of speed, governor valve position, or load demand settings.
   b) Numeric in-line display of speed, governor valve position, or load references.
   c) Back-lighted pushbuttons for:
      1 Operator automatic.
      2 Turbine manual.
      3 Raise, lower and fast manual throttle valve control.
      4 Raise, lower and fast manual governor valve control.
      5 Impulse pressure out of service.
      6 Impulse pressure in service.
      7 Transfer from full to partial arc admission.
      8 Single valve operation. (when applicable)
      9 Sequential valve operation. (when applicable)
      10 Speed or load reference setter buttons with "go" and "hold".
      11 Acceleration, rpm/min.
      12 Load rate, mw/min.
      13 Speed control reset.
      14 Controller reset.
      15 Throttle pressure regulator out of service.
      16 Throttle pressure regulator in service.
      17 Megawatt feedback loop out of service.
      18 Megawatt feedback loop in service.
      19 Governor valve position limit display, limit raise and lower.
      20 Data entry keyboard, including the following pushbuttons:
         a Enter
         b Cancel
         c Turbine program display
         d Integers 0 through 9
         e Decimal point
         f Minus sign
      21 Valve testing/status pushbuttons, including:
         a Valve test
         b Valve status
         c Throttle valve
         d Governor valve
         e Open
         f Close
   d) Indicating light for:
      1 "Invalid request"
   e) Maintenance test key switch with two poistions:
      1 Off
      2 Test
   f) O.P.C. test key switch with three positions:
      1 O.P.C. test
      2 In service
      3 Overspeed test permissive
   g) Phone jack

3) Valve test panel
   a) Back-lighted pushbuttons for:
      1 Latch
      2 Test left interceptor and reheat stop valves.
      3 Test right interceptor and reheat stop valves.
   b) Indicating lights for:
      1 Throttle valves open and closed.
      2 Governor valves open and closed.
      3 Reheat stop valves open and closed.
      4 Interceptor valves open and closed.

E Automatic synchronizer to be mounted by Purchaser. Wiring to the synchronizer and the DEH cabinet to be provided by the Purchaser. Control system interface with the automatic synchronizer is included.

F IBM 735 Selectric typewriter.

No change since previous issue.

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-inch Last Row Blades and Larger

Steam Turbines, Continued

Standard Features and Accessories, Continued

G Super Bee 15 inch black and white CRT suitable for mounting and wiring by the Purchaser in his panels. Included is the computer software for the display of control system data on operator demand.

H Interconnecting cables between digital controller and operator's panel, where distance between controller and panel does not exceed 50 feet.

I Power supplies for digital controller.

J Autostop and emergency trip system with continuous protection while performing on-line testing.

1) Mechanical hydraulic overspeed trip with 4½" oil trip test gauge, for manual overspeed trip test.
2) Remote test of mechanical overspeed trip.
3) Electrical overspeed trip device.
4) Turbine protective devices, with remote test including:
   a) Low bearing oil pressure trip with 4½" trip test gauge.
   b) Low vacuum trip with 4½" trip test gauge.
   c) Thrust bearing wear and rotor movement trip.
   d) Low E-H fluid pressure trip.
5) Electrical solenoid trip.

3 Complete lubricating oil pumping system (oil not included), consisting of the following:

A Main oil pump on the turbine shaft.

B Oil reservoir, including:
1) Float-type oil level indicator.
2) Float-type high and low level alarm device.
3) Top-mounted relief and access doors.
4) Bearing oil pump (a-c motor-driven).
5) Emergency bearing oil pump (d-c motor-driven) and motor starter.
6) High pressure hydrogen seal oil back-up pump (a-c motor-driven).
7) Oil ejector.
8) Motor-operated vapor extractor.
9) Oil strainers located at each motor-driven pump and oil ejector suction and at the oil return to the reservoir.

Note: A-c motors will be 460 or 575 volts, 3 phase D-c motors will be 120 or 240 volts (±10% voltage variation).
All motors will be open, drip-proof construction with Class B insulation, for 40 C ambient.

①C Twin full-size oil coolers with ⅝ in. O.D., 20 BWG, 90-10 copper-nickel tubes for 95 F cooling water at a maximum working pressure of 125 psig②, and with interconnecting oil piping and a manual three-way valve.

D Pressure switches with test valves for automatic starting of the bearing oil pump and emergency bearing oil pump.

E Complete interconnecting oil piping to and from all bearings, oil reservoir and oil coolers. (Pipe hangers **not** included.)

F Plate-type oil demister, mounted by Westinghouse.

4 Gland sealing system, consisting of the following:

A Steam sealed glands.

B Pneumatically operated gland steam regulators (and spillover regulator when required).

C Motor-operated shutoff and bypass valves, for high pressure regulator.

D Manual shutoff and motor-operated by-pass valves for the spillover regulator, when required by design.

E Motor-operated shutoff valve only for cold reheat regulator.

F Surface-type gland steam condenser with stainless steel tubes and level alarm, designed for 400 psig maximum and 125 F cooling water with a motor-driven exhauster designed for 0.25 psig maximum discharge pressure.

G Temperature-sensing element and spray desuperheater ahead of low-pressure glands.

H Steam seal piping from the regulators to the turbine and from the turbine to the gland condenser, including high pressure and spillover regulator bypasses. (Pipe hangers **not** included.)

5 Pneumatic-operated drain valves and piping from turbine to the drain valves.①

6 Exhaust casing spray nozzles, and a power-operated valve for mounting in Purchaser's water supply piping.

7 Motor-operated rotor turning gear with manual and automatic engagement, including a jog switch and a zero-speed sensing device, interlocked with the lubrication system through a pressure switch to prevent operation without bearing lubrication.

8 Protective devices, consisting of the following:

A Turbine exhaust casing relief diaphragms.

B Exhaust casing alarm thermocouple operating via metal temperature recorder. (One per exhaust connection).

C Oil-operated pilot dump valve for • positive closing of the Purchaser's extraction steam nonreturn valves.

9 Appropriate supervisory instruments (for Purchaser's mounting) to suit the unit, including:

A Recording type:
1) Turbine rotor eccentricity.
2) Rotor vibration.
3) Turbine rotor position.
4) Turbine casing expansion.
5) Turbine casing and rotor differential expansion.
6) Speed and governor valve position. (Items (1) through (6) have outputs compatible for use with computers.)
7) Steam and metal temperatures for turbine operation.

B Vibration phase angle meter and selector switch. Includes shaft mounted reference detector and required circuitry.

C Eccentricity phase angle meter. Includes shaft mounted reference detector and required circuitry.

10 Thermocouples: (Simplex type unless indicated otherwise)

A For measurement of turbine steam and metal temperatures for the purpose of turbine operation.

B Embedded in each of two thrust bearing shoes on each side (one duplex and one simplex).

C Embedded in metal of the main bearings. (Duplex)

D For all main bearing drains.

E For the thrust bearing drains.

F For the oil inlet and outlet of the oil coolers.

11 Thermometers, consisting of the following:

A For all main bearing drains.

B For the thrust bearing drains.

C For the oil inlet and outlet of the oil coolers.

① Changed since previous issue.
② 150 psig at no change in price.
③ Motor-operated at no change in price.

Westinghouse

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Steam Tubines, Continued

Standard Features and Accessories, Continued

12 Oil pressure gauges (4½ inch diameter) mounted on the equipment, or loose for Purchaser's mounting, for the following:

A Bearing header.

B Main oil pump suction.

C Main oil pump discharge.

D Bearing oil pump discharge.

E Emergency bearing oil pump discharge.

13 Miscellaneous instruments, consisting of the following (mounted on the Westinghouse piping unless otherwise indicated):

A Electric transmitter and receiver for steam seal pressure. (Loose for Purchaser's mounting)

B Electric transmitter for inlet steam pressure (if required). (Loose receiver for Purchaser's mounting).

C Electric transmitter for steam chest pressure. (If required).

D Electric transmitter for reheat steam pressure (if required). (Loose Receiver for Purchaser's mounting).

E Pressure gauge (4½ inch diameter) for the exhaust hood water spray.

F Pressure gauge (2.0 inch diameter) for the gland exhauster vacuum.

G Up to 5 indicating lights (for Purchaser's mounting).

14 Rotor-grounding device.

15 Turbine steel appearance lagging (indoor units). (Embedded lagging sills to be furnished by Purchaser.)

16 Insulating material, in accordance with factory specifications for installation by the Purchaser, consisting of the following:

A Block and plastic (or spray type) heat insulating material for upper and lower turbine casings, steam valve bodies and exhaust casings, where required.

B Preformed segmental pipe insulation with aluminum jacketing for all steam piping furnished by Westinghouse.

C Removable expanded metal flange enclosures covered with block and plastic insulation, or removable wire mesh encased blankets, as required by design for the combination stop-throttle valves, reheat stop and interceptor valves, flanges at the turbine, and flanges in crossover pipes where required.

D Purchaser has the option of selecting one of the following, in accordance with factory specifications, for the turbine casing(s) horizontal flange joint(s) that must be parted for turbine disassembly:

1) Block and plastic or any combination thereof.
2) Reusable blankets.
3) Block and plastic on removable, reusable steel cages.

17 Set of lifting slings and special tools and wrenches (one set only, for similar or duplicate units in the same station of Purchaser).

18 Turbine exhaust template (when required).

19 Shims, seating and soleplates required to set and align the unit.

20 Instruction books (twenty-five (25) copies) and operator Equipment Familiarization Manuals (up to 30 copies).

No change since previous issue.

Prices effective October 30, 1974; subject to change without notice.

October 30, 1974
Supersedes Price List 1252, dated July 1, 1974
E, C/1663/PL

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Alternating Current Generators

Rating

Synchronous turbine generators are rated at the maximum kva load they are guaranteed to be capable of carrying continuously without exceeding their temperature guarantees. The ratings are expressed in kilovolt-amperes at 0.90 power factor, 0.58 short-circuit ratio at the maximum design gas pressure.

3600 rpm and 1800 rpm generators rated 210,000 kva and smaller will be conventional-cooled. 3600 rpm and 1800 rpm generators rated above 210.000 kva will be inner-cooled.

The bill of material and technical data for conventionally-cooled generators are in Price List 1232.

Short-Circuit Ratio

The short-circuit ratio is the ratio of the field ampere-turns required to produce rated voltage at no-load and at rated frequency, to the field ampere-turns required to produce rated armature current at sustained short circuit.

Standard short-circuit ratio at rated kva for the turbine generators included in this price list will not be less than 0.58.

Temperature Rises

Inner-cooled generators have maximum guaranteed temperatures based on maximum design gas pressures and on a cooling water temperature of 95 F or lower as follows:

Cooling Hydrogen: 45 C to 50 C by detector.

Armature Winding: 65 C to 60 C rise (depending on cooling hydrogen temperature), by detectors in coolant from armature winding.

Cooling water to armature winding – 45 C to 50 C by thermocouple. (where applicable)

Warm water from armature winding – 55 C to 50 C rise (depending on cooling water temperature) by thermocouple in coolant from armature winding. (where applicable)

Field Winding: 65 C to 60 C rise (depending on cooling hydrogen temperature) by resistance.

Allowable Voltage Variation

Generator will operate successfully at rated kva, frequency, power factor and gas pressure at any voltage not more than 5 percent above or below rated voltage, but not necessarily in accordance with the standards of performance established for operation at rated voltage.

No change since previous issue.

Class of Insulation

Class B insulation is standard for armature and field windings.

Abnormal Conditions

Short Time Thermal Capability Balanced Currents

The generator armature will be capable of operating at 130 percent of rated armature current and the field winding at 125 percent of rated load field voltage for one minute and for other times up to 120 seconds based upon the same increment of heat storage, all starting from stabilized temperatures at rated conditions.

This capability is based on the assumption that the number of operations under these conditions will not exceed two times per year.

Short Time Thermal Capability Unbalanced Currents

The generator will be capable of withstanding, without injury, the effects of unbalanced currents resulting from short circuit at the machine terminals for times up to 120 seconds, provided the integrated product (I_2^2T) of generator negative phase sequence current (I_2) and time (T) does not exceed 10 for inner-cooled generators up to 800 mva, and the value obtained from the formula 10-(.00625) (mva-800) for generators rated 800 mva to 1600 mva.

(Negative phase sequence current (I_2) is expressed in per unit stator current at rated kva and time (T) in seconds.)

Mechanical Capability

Generators will be capable of withstanding, without mechanical injury, any type of short circuit at the machine terminals for times not exceeding the Short Time Thermal Capability, when operating at rated kva and power factor and 5 percent overvoltage; provided the maximum phase current is limited by external means to a value which does not exceed the maximum phase current obtained from a 3 phase fault.

In the case of stator windings, the criterion for no injury is that the windings will satisfactorily withstand a normal maintenance high potential test. There will be no visible abnormal deterioration or damage to the winding coils and connections.

Wave Form

The deviation factor of a wave is the ratio of the maximum difference between corresponding ordinates of the wave and of the equivalent sine wave to the maximum ordinate of the equivalent sine wave when the waves are superimposed in such a way as to make this maximum difference as small as possible.

The deviation factor of the open-circuit terminal voltage wave of synchronous generators will not exceed 10 percent.

Telephone Influence Factor

Turbine generators included in this price list have a balanced line to line, no-load open-circuit, normal voltage TIF not exceeding 40.

The residual component will not exceed 30.

Capacity as Synchronous Condenser

Special starting provisions and equipment are required for this operation. Extra features may be added for a price addition (refer to Steam Turbine Division, Marketing Department) which will permit the operation of listed generators as synchronous condensers.

The generator kva capacity at zero power factor, over-excited as a synchronous condenser, is equivalent to the kva capacity at zero power factor as shown on the generator capability curve.

Tests

The following standard commercial factory tests will be made on the generator:

Mechanical

1 Rotor overspeed
2 Rotor mechanical balance
3 Mechanical inspection
4 Air leakage test

Electrical

1 Measurement of cold resistance of armature and field windings.
2 Insulation resistance measurements
3 Dielectric tests:

Armature: The standard test voltage shall be an alternating voltage whose effective value is twice the rated voltage of the machine, plus 1000 volts, applied for 60 seconds.

Field: The standard test voltage for field voltages up to and including 500 volts is a voltage of ten times the rated voltage, but not less than 1500 volts. The standard test voltage for field voltages rated greater than 500 volts is 4000 volts plus twice the rated volts. This test is applied for 60 seconds.

4 Resistance temperature detector test.

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Alternating Current Generators, Continued

Altitude

Generator ratings specified herein are based on operation when the generator is installed at an elevation of 3300 feet or less above sea level. Generators operated at altitudes above 3300 feet will have the gauge pressure of the hydrogen in the generator casing increased above the gauge pressure specified in this price list so as to maintain the same absolute casing pressure as that required for operation at sea level.

No change since previous issue.

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Alternating Current Generators, Continued

Standard Features and Accessories

Each generator is of the totally enclosed, self-ventilated, non-salient pole-type and includes the following standard features and accessories:

Hydrogen Inner-cooled Generators

①1 Hydrogen coolers with 90-10 copper nickel tubes mounted within the generator housing and designed to operate with 95 F and lower cooling water at a maximum pressure of 125 psig②.

2 Generator field discharge resistor for mounting in excitation cubicle. (Not included when brushless excitation system is furnished.)

3 Six (6) high-voltage bushings.

4 Twelve (12) bushing current transformers (two (2) per terminal) with provisions for one additional transformer per bushing.

5 Hydrogen system:

A Seal oil unit assembled on a base and including:

1) One hydrogen side and one air side seal oil pump, both with totally enclosed a-c motors.

2) Air side seal oil back-up pump with totally enclosed d-c motor.

3) Hydrogen side seal oil cooler and filter.

4) Air side seal oil cooler and filter.

5) Main pump relief valves.

6) Differential pressure switch with alarm contacts for annunciator and for activation of back-up pump including manual test valves.

7) Pressure switch with alarm contacts for seal oil back-up from turbine.

8) Two differential pressure switches with alarm contacts across air side and hydrogen side seal oil pumps.

9) Float switch with alarm contacts in seal drain system.

10) Gauge panel with:

a Air side seal oil pressure gauge.

b Two differential pressure gauges for measuring differential between hydrogen side and air side seal oil pressures.

c Test gauge for hydrogen side seal oil pressure.

d Test gauge for air side main and back-up seal oil pumps.

e Test gauge for turbine seal oil back-up pressure.

f Test gauge for checking starting of air side seal oil back-up pump.

(Note: Test gauges are mounted at point of test.)

11) Junction box for electrical connections (except for motors).

12) Necessary check valves and shutoff valves.

13) Generator gas temperature thermostat with alarm contacts.

B The following are furnished for field assembly:

1) Seal oil loop seal system, including a seal tank with interconnecting piping, bypass and/or check valves where required, and motor-operated vapor extractor.

2) Steel pipe and weld type fittings for seal oil piping (excluding vent piping).

3) Hydrogen drier and blower.

C Hydrogen and carbon dioxide systems, including:

1) Hydrogen manifold with one bottle pressure regulator with high and low pressure gauges, shutoff valves and four bottle connectors.

2) Manual generator hydrogen pressure regulator and manual bypass valve for fast feeding (in series with bottle pressure regulator).

3) Carbon dioxide manifold with pressure gauge, relief valve, shutoff valves, mounting brackets, and four bottle connectors.

4) Purging control valve assembly.

5) Three generator casing liquid detectors with alarm contact.

6) Steel pipe and weld type fittings for gas control system (excluding vent lines).

D Hydrogen control cabinet, consisting of:

1) Gas compartment, including:

a Dual pressure gauge for indication of machine gas pressure and generator fan pressure. Machine gas pressure electrically transmitted and equipped with high and low alarm contacts.

b Pressure compensated gas purity meter (and blower) for purity indication, electrically transmitted and equipped with high and low alarm contacts.

Compartment wiring and gas-tight wiring seal into hydrogen electrical compartment.

d Compartment piping with pipe adapters at top of compartment.

2) Electrical compartment (separated from gas compartment by a gas-tight partition), including:

a Annunciator with d-c pilot light, alarm contacts and manual reset.

b Relay for loss of d-c supply with contact for remote alarm.

c D-c horn for annunciator alarms.

d Switches for ac and dc supply including overload protection.

e Necessary terminal blocks and wiring.

f Alarm switches referred to in gas compartment are mounted in electrical compartment.

g Control wiring.

h Interior light.

3) Electrical receiver for generator gas pressure, for mounting by Purchaser at generator hydrogen supply manifold.

NOTE: For cross-compound units combined gas and seal oil systems will be provided wherever practicable; otherwise separate individual systems will be furnished.

6 Temperature detectors (resistance type – 10 ohms at 25 C) as follows:

A One (1) for each cooler outlet cold gas.

B One (1) in common hot gas inlet to coolers.

C One (1) (including immersion well) in common cold gas outlet from hydrogen coolers for control of hydrogen temperature by Purchaser.

D Six (6) in armature coil discharge gas of 2-pole generators.

E Twelve (12) in armature coil discharge gas of 4-pole generators.

7 Generator condition monitor.

8 Special tools:

A Necessary rotor removal and installation tools.

B Gap barrier tensioning tool, if required.

C Cooler, bushing, bearing and bearing bracket assembly tools where applicable.

D Set of rotor lifting cables.

NOTE: (If duplicate or similar generator is located in same station of the Purchaser, only those special tools, wrenches and cables unique to the new generator will be supplied).

① Changed since previous issue.
② 150 psig at no change in price.

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Alternating Current Generators, Continued

Hydrogen Inner-Cooled Generators, Continued

E Stator jacking or lifting trunnions. (Provided on a loan basis and to be returned to Westinghouse.)

9 Miscellaneous:

A Generator frame grounding pads.

B Seating plates, shims and soleplates.

•C Removable appearance lagging from centerline to floor. (Embedded support plates not included.)

Hydrogen Inner-Cooled Generators, With Water Cooled Stator Winding

①1 Hydrogen coolers with 90-10 copper nickel tubes mounted within the generator housing and designed to operate with 95 F and lower cooling water at a maximum pressure of 125 psig②.

2 Generator field discharge resistor for mounting in excitation cubicle. (Not included when brushless excitation system is furnished.)

3 Six (6) high-voltage bushings.

4 Twelve (12) bushing current transformers (two (2) per terminal) with provisions for one additional transformer per bushing.

5 Hydrogen system:

A Seal oil unit assembled on a base and including:

1) One hydrogen side and one air side seal oil pump, both with totally enclosed a-c motors.

2) Air side seal oil back-up pump with totally enclosed d-c motor.

3) Hydrogen side seal oil cooler and filter.

4) Air side seal oil cooler and filter.

5) Main pump relief valves.

6) Differential pressure switch with alarm contacts for annunciator and for activation of back-up pump including manual test valves.

7) Pressure switch with alarm contacts for seal oil back-up from turbine.

8) Two differential pressure switches with alarm contacts across air side and hydrogen side seal oil pumps.

9) Float switch with alarm contacts in seal drain system.

10) Gauge panel with:

a Air side seal oil pressure gauge.

b Two differential pressure gauges for measuring differential between hydrogen side and air side seal oil pressures.

c Test gauge for hydrogen side seal oil pressure.

d Test gauge for air side main and back-up seal oil pumps.

e Test gauge for turbine seal oil back-up pressure.

f Test gauge for checking starting of air side seal oil back-up pump.

NOTE: Test gauges are mounted at point of test.

11) Junction box for electrical connections (except for motors).

12) Necessary check valves and shutoff valves.

13) Generator gas temperature thermostat with alarm contacts.

B The following are furnished for field assembly:

1) Seal oil loop seal system, including a seal tank with interconnecting piping, bypass and/or check valves where required, and motor-operated vapor extractor.

2) Steel pipe and weld type fittings for seal oil piping (excluding vent piping).

3) Hydrogen drier and blower.

C Hydrogen and carbon dioxide systems, including:

1) Hydrogen manifold with one bottle pressure regulator with high and low pressure gauges, shutoff valves and four connectors.

2) Manual generator hydrogen pressure regulator and manual bypass valve for fast feeding (in series with bottle pressure regulator).

3) Carbon dioxide manifold with pressure gauge, relief valve, shutoff valves, mounting brackets, and four bottle connectors.

4) Purging control valve assembly.

5) Three generator casing liquid detectors with alarm contact.

6) Steel pipe and weld type fittings for gas control system (excluding vent lines).

D Hydrogen control cabinet, consisting of:

1) Gas compartment, including:

a Dual pressure gauge for indication of machine gas pressure and generator fan pressure. Machine gas pressure electrically transmitted and equipped with high and low alarm contacts.

b Pressure compensated gas purity meter (and blower) for purity indication, electrically transmitted and equipped with high and low alarm contacts.

c Compartment wiring and gas-tight wiring seal into hydrogen electrical compartment.

d Compartment piping with pipe adapters at top of compartment.

2) Electrical compartment (separated from gas compartment by a gas-tight partition), including:

a Annunciator with d-c pilot light, alarm contacts and manual reset.

b Relay for loss of d-c supply with contact for remote alarm.

c D-c horn for annunciator alarms.

d Switches for a-c and d-c supply including overload protection.

e Necessary terminal blocks and wiring.

f Alarm switches referred to in gas compartment are mounted in electrical compartment.

g Control wiring.

h Interior light.

3) Electrical receiver for generator gas pressure, for mounting by Purchaser at generator hydrogen supply manifold.

NOTE: For cross-compound units combined gas and seal oil systems will be provided wherever practicable; otherwise separate individual systems will be furnished.

6 Stator coil cooling water system:

A Stator coil cooling water unit assembled on a base, including:

1) One main and one full capacity back-up water circulating pump, both with totally enclosed a-c motors.

2) Pressurized water reservoir.

3) Two (2) water-to-water heat exchangers.

① Changed since previous issue.
② 150 psig at no change in price.

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Alternating Current Generators, Continued

Hydrogen Inner-Cooled Generators, With Water Cooled Stator Winding
Continued

4) Two (2) 50 gpm deionizers.

5) Filters, gauges, conductivity cells, pressure switches and regulating equipment as necessary.

6) Gauge to indicate differential pressure between generator stator coil cooling water inlet and discharge manifolds and alarm.

7) Water reservoir pressure gauge.

B Stator coil cooling water control cabinet combined with the hydrogen control cabinet, including:

1) Conductivity recorders and alarms.

C Valves and piping as required, except hydrogen vent lines and water supply lines to coolers.

7 Temperature detectors as follows:

A One (1) resistance type for each cooler outlet cold gas.

B One (1) resistance type in common hot gas inlet to coolers.

C One (1) (including immersion well) in common cold gas outlet from hydrogen coolers for control of hydrogen temperature by Purchaser.

D Six (6) resistance type embedded in armature windings.

E One (1) thermocouple in each stator coil discharge header.

F One (1) thermocouple in cooler water inlet.

G One (1) thermocouple in cooler water outlet.

NOTE: Resistance type – 10 ohms at 25 C.

8 Generator condition monitor

9 Special tools:

A Necessary rotor removal and installation tools.

B Gap barrier tensioning tool, if required.

C Cooler, bushing, bearing, and bearing bracket assembly tools, where applicable.

D Set of rotor lifting cables.

NOTE: (If duplicate or similar generator is located in same station of the Purchaser, only those tools wrenches and cables unique to the new generator will be supplied.)

E Stator jacking or lifting trunnions. (Provided on a loan basis and to be returned to Westinghouse.)

10 Miscellaneous:

A Generator frame grounding pads.

B Seating plates, shims and soleplates.

C Removable appearance lagging from centerline to floor. (Embedded support plates not included.)

No change since previous issue.

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Excitation System

The excitation for generators covered in this price list is supplied by a brushless excitation system.

The brushless excitation system consists of a permanent magnet pilot exciter (PMG), an a-c exciter, a diode and fuse wheel directly connected to the generator shaft with a static voltage regulator and associated excitation switchgear.

For other types of excitation systems, refer to Steam Turbine Division Marketing Department.

Excitation Tests
Standard factory tests, will include the following unless specifically waived:

1 Mechanical balance.
2 Measurement of cold resistances.
3 High-potential tests.
4 Overspeed test.
5 Resistance temperature detector tests.

Rotating exciters will be completely assembled in the factory and run at speed.

Exciter Temperature Guarantees
Brushless exciters are rated on the basis of continuous operation at rated output and will not exceed a guaranteed maximum temperature rise of 70 C for Class B insulation and 90 C for Class F insulation above an ambient of 40 C based on the standard 95 F cooling water requirement at an altitude of 3300 feet or less.

Excitation Systems and Accessories

I **Brushless Excitation System (Air Cooled)**

1 Permanent magnet pilot exciter for excitation to the a-c exciter through the excitation switchgear.

2 A-c exciter with a rotating armature and a stationary field winding.

3 Rotating rectifier assembly including silicon diodes, indicating fuses, and other components.

4 All necessary electrical interconnections.

5 Set of mechanical parts, including:

A Fabricated steel bedplate.

B Air-to-water heat exchanger.

C Insulated pressure-lubricated pedestal bearing.

D Temperature detectors (resistance type – 10 ohms at 25 C) as follows:

1) Two (2) for cold air temperature.

2) Two (2) for hot air temperature.

E Dripproof enclosure mounted on the exciter base with the following features:

1) Door or access cover with glass window opposite the fuse and diode wheels.

2) Door or access cover at the end of the housing for access to the permanent magnet generator.

3) All doors are provided with locking devices to insure they remain closed during normal operation.

4) Set of internal lights, switches and convenience outlet.

5) Hydrogen vent.

6 Terminal board in exciter base, and internal wiring in exciter for application of excitation system automatic ground detection device.

7 Indicating fuses for visual inspection during operation.

8 Convenience outlet.

9 Exciter base ground connection.

10 Type WTA solid state voltage regulating equipment and associated excitation switchgear, including:

A One set of metal enclosed excitation cubicles with ventilating means as required to maintain permissible heat rise and including the following:

1) Static voltage regulator including the required reference and sensing circuits.

2) Reactive droop compensator for parallel operation.

3) Static minimum excitation limiter.

①4) Static maximum excitation limiter, and over excitation protector.

5) Volts per Hertz protection equipment.

6) Static power amplifier and associated firing circuits.

7) Excitation system stabilizer.

8) Protection devices annunciator.

9) A-c exciter field breaker.

10) Mounted and wired instruments as required by Westinghouse for monitoring operation.

11) Exciter field current shunt.

12) Automatic generator field ground detector.

13) Motor operated base adjuster.

14) Motor operated voltage adjuster with range width setter.

15) Set of bare busses

16) Set of terminals of suitable size and rating for outgoing leads.

17) Set of nameplates.

18) Set of small wiring.

19) Set of internal lights, switches and convenience outlets.

20) Set of pull fuses for control power.

21) Field current-isolating transducer.

22) Field voltage-isolating transducer.

B One set of devices for remote mounting and wiring by the Purchaser.

1) Zero center regulator output balancing meter.

2) Type W-2 control switch and integral position indicator for motor operated base adjuster.

3) Type W-2 control switch and integral position indicator for motor operated voltage adjuster.

4) Type W-2 regulator control switch and indicating lights.

5) Type W-2 a-c exciter field breaker control switch and indicating lights.

① Changed since previous issue.

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Excitation Systems and Accessories, Continued

II Brushless Excitation System (Hydrogen Cooled)

1 Permanent magnet pilot exciter for excitation to the a-c exciter through the excitation switchgear, located at the end of the exciter shaft outside the exciter hydrogen enclosure.

2 A-c exciter with a rotating armature and a stationary field winding.

3 Rotating rectifier assembly including silicon diodes, indicating fuses, and other components.

4 All necessary electrical interconnections.

5 Set of mechanical parts, including:
- A Hydrogen-tight enclosure.
- B Shaft gland seals.
- C Insulated pressure-lubricated bearing with bearing bracket.
- D Inspection window(s) adjacent to the fuse and diode wheel(s).

6 Necessary parts and functions coordinated with generator hydrogen system, to operate exciter cooling system:
- A Hydrogen feed to exciter enclosure.
- B Carbon dioxide feed to exciter enclosure.
- C Exciter enclosure hydrogen control valves.
- D Exciter enclosure liquid detector with alarm contact.
- E Hydrogen intake and discharge lines to appropriate zones of generator casing, to provide cooling of exciter from main generator cooling system.
- F Pressure compensated gas purity meter with blower and alarm contact for exciter enclosure gas purity indication pneumatic transmission, mounted in hydrogen control cabinet.
- G Additional alarm contacts for annunciator to provide functions necessary for hydrogen control for the exciter.
- H Exciter gas temperature thermostat with alarm contacts.

7 Temperature detectors (resistance type – 10 ohms at 25 C) as follows:
- A One (1) for cold gas temperature.
- B One (1) for hot gas temperature.

8 Connection to seal oil unit.

9 Terminal board in exciter base, and internal wiring in exciter for application of excitation system automatic ground detection device.

10 Indicating fuses for visual inspection during operation.

11 Convenience outlet.

12 Exciter base ground connection.

13 Type WTA solid state voltage regulating equipment and associated excitation switchgear, including:
- A One set of metal enclosed excitation cubicles with ventilating means as required to maintain permissible heat rise and including the following:
  - 1) Static voltage regulator including the required reference and sensing circuits.
  - 2) Reactive droop compensator for parallel operation.
  - 3) Static minimum excitation limiter.
  - Ⓓ4) Static maximum excitation limiter, and over excitation protector.
  - 5) Volts per Hertz protection equipment.
  - 6) Static power amplifier and associated firing circuits.
  - 7) Excitation system stabilizer.
  - 8) Protection devices annunciator.
  - 9) A-c exciter field breaker.
  - 10) Mounted and wired instruments as required by Westinghouse for monitoring operation.
  - 11) Exciter field current shunt.
  - 12) Automatic generator field ground detector.
  - 13) Motor operated base adjuster.
  - 14) Motor operated voltage adjuster with range width setter.
  - 15) Set of bare busses.
  - 16) Set of terminals of suitable size and rating for outgoing leads.
  - 17) Set of nameplates.
  - 18) Set of small wiring.
  - 19) Set of internal lights, switches and convenience outlets.
  - 20) Set of pull fuses for control power.
  - 21) Field current-isolating transducer.
  - 22) Field voltage-isolating transducer.
- B One set of devices for remote mounting and wiring by the Purchaser.
  - 1) Zero center regulator output balancing meter.
  - 2) Type W-2 control switch and integral position indicator for motor operated base adjuster.
  - 3) Type W-2 control switch and integral position indicator for motor operated voltage adjuster.
  - 4) Type W-2 regulator control switch and indicating lights.
  - 5) Type W-2 a-c exciter field breaker control switch and indicating lights.

Ⓓ Changed since previous issue.

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Table A: Basic List Prices
Prices—in Thousands of Dollars—Include Freight and Technical Direction of Installation

Basic Unit Turbine Rating, Kw	Generator Rating, Kva	Turbine Exhaust Ends	Basic List Price
Tandem Compound—3600 Rpm			
200,000	240,000	2-25"	$10,900
275,000	330,000	2-28.5"	13,800
325,000	390,000	2-31"	15,800
325,000	390,000	4-23"	16,000
425,000	510,000	4-25"	18,900
550,000	660,000	4-28.5"	23,500
650,000	780,000	4-31"	27,200
800,000	960,000	6-28.5"	32,900
950,000	1,140,000	6-31"	38.100
Cross Compound—3600/3600 Rpm			
325,000	390,000	4-23"	18,400
425,000	510,000	4-25"	21,600
500,000	600,000	6-23"	23,600
550,000	660,000	4-28.5"	26,000
650,000	780,000	4-31"	29,600
800,000	960,000	6-28.5"	35,000
850,000	1,020,000	8-25"	36,700
950,000	1,140,000	6-31"	40,300
1,100,000	1,320,000	8-28.5"	45,700
1,200,000	1,440,000	8-31"	49,200
Cross Compound—3600/1800 Rpm			
500,000	600,000	2-40"	24,000
650,000	780,000	2-44"	29,200
850,000	1,020,000	2-52"	37,600
1,000,000	1,200,000	4-40"	42,500
1,200,000	1,440,000	4-44"	49,000
1,400,000	1,680,000	6-40"	56,600
1,500,000	1,800,000	4-52"	60,700
1,500,000	1,800,000	6-44"	64,200

Pricing for Units with Capability other than Listed in Table A

1. Add or deduct turbine capability at $9.00/kw for each kw more or less than listed in table for base machine of the type desired.
2. Add or deduct generator capability at $7.50/kva for each kva more or less than listed in table for base generator rating.

Table A-1: Basic List Prices for High Back Pressure Units
For prices for units with high back pressures, refer to the Steam Turbine Marketing Department.

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Table B: Price Additions for Pressure (Psig)
Prices—in Thousands of Dollars

Turbine Rating, Kw	Initial Pressure Range, Psig② 1250-1450	1600-1800	2200-2400	3200-3500	4100-4500
150,000	$ 120	$ 0	$ 300	$840	$1,200
200,000	300	0	120	540	1,000
300,000	540	120	0	300	800
400,000	840	300	0	120	600
500,000	1,200	540	120	0	700
600,000	1,620	840	300	0	800
700,000	......	1,200	540	0	900
800,000	......	1,620	840	0	1,000
900,000	......	2,100	1,200	0	1,100
1,000,000	......	......	1,620	0	1,200
1,100,000	......	......	2,100	0	1,300
1,200,000	......	......	2,640	0	1,400
1,300,000	......	......	3,240	0	1,500
1,400,000	......	......	3,900	0	1,600
1,500,000	......	......	4,620	0	1,700

②For pressures between those listed above, use the adjoining pressure range which results in the higher price

Table C: Price Additions for Temperature (F)
Prices—in Thousands of Dollars

Turbine Rating, Kw	Initial Temperature Range 826-900	901-950	951-1000	1001-1050	1051-1100	First Reheat Temperature Range 826-900	901-950	951-1000	1001-1025	1026-1050	Second Reheat Temperature Range 1000	1001-1025	1026-1050
150,000	−$ 60	−$ 40	$0	$180	$ 480	−$ 60	−$ 40	$0	$300	$500	$1,600	$1,800	$2,000
200,000	− 90	− 60	0	180	480	− 90	− 60	0	300	500	1,600	1,800	2,000
300,000	− 120	− 80	0	240	480	− 120	− 80	0	300	500	1,600	1,800	2,000
400,000	− 150	− 100	0	300	600	− 150	− 100	0	300	500	1,600	1,800	2,000
500,000	− 180	− 120	0	360	720	− 180	− 120	0	300	500	1,700	1,900	2,100
600,000	− 210	− 140	0	420	840	− 210	− 140	0	320	520	1,800	2,000	2,220
700,000	− 240	− 160	0	480	960	− 240	− 160	0	340	540	1,900	2,100	2,340
800,000	......	− 180	0	540	1,080	......	− 180	0	360	560	2,000	2,200	2,460
900,000	......	......	0	600	1,200	......	......	0	380	580	2,100	2,300	2,580
1,000,000	......	......	0	660	1,320	......	......	0	400	600	2,200	2,400	2,700
1,100,000	......	......	0	720	1,440	......	......	0	420	620	2,300	2,500	2,820
1,200,000	......	......	0	780	1,560	......	......	0	440	640	2,400	2,600	2,940
1,300,000	......	......	0	840	1,680	......	......	0	460	660	2,500	2,700	3,060
1,400,000	......	......	0	900	1,800	......	......	0	480	680	2,600	2,800	3,180
1,500,000	......	......	0	960	1,920	......	......	0	500	700	2,700	2,900	3,300

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Table D: Special Turbine Equipment, Features and Requirements—200,000 to 700,000 Kw
Prices in Dollars

	Turbine Rating, Mw								
	200	250	300	350	400	450	500	600	700
1 Technical Direction of Installation (Deduct for omission)②	$128 000	$146 000	$164 000	$182 000	$200 000	$218 000	$218 000	$238 000	$308 000
2. Turbine tests									
a Turbine acceptance test in field at Purchaser's request③	130 000	140 000	150 000	160 000	170 000	180 000	190 000	200 000	215 000
b Turbine connections for Purchaser's test④	17 000	18 500	20 000	21 500	23 000	24 500	26 000	29 000	32 000
c Turbine connections for Purchaser's enthalpy drop tests⑤	1 400	1 700	2 000	2 300	2 600	2 900	3 200	3 800	4 400
3. Extractions									
a For each type auxiliary turbine application with steam from auxiliary turbine entering into the feed-water heating cycle⑥									
1. Does not re-admit to main turbine	50 000	50 000	55 000	55 000	60 000	60 000	70 000	80 000	90 000
2. Re-admits to main turbine	110 000	110 000	120 000	130 000	150 000	160 000	170 000	190 000	210 000
b For other uncontrolled extraction⑦	18 000	22 500	27 000	31 500	36 000	40 500	45 000	54 000	63 000
c Single-automatic extraction for condensing units	← Refer to Factory →								
d Double-automatic extraction for condensing units	← Refer to Factory →								
4. Side exhaust openings⑧									
a Below Floor line									
1. 3600-rpm, double-flow	140 000	160 000	180 000	....	....	....	....	....	....
2. 3600-rpm, four-flow	200 000	220 000	240 000	260 000	280 000	300 000	320 000	360 000	400 000
3. 3600-rpm, six flow	....	....	280 000	310 000	340 000	370 000	400 000	460 000	520 000
b Above Floor line									
1. 3600-rpm, double-flow	190 000	210 000	230 000	....	....	....	....	....	....
2. 3600-rpm, four-flow	250 000	270 000	290 000	310 000	330 000	360 000	400 000	460 000	520 000
3. 3600-rpm, six flow	....	....	360 000	390 000	420 000	460 000	510 000	590 000	670 000
4. 1800-rpm, double flow	300 000	330 000	360 000	390 000	420 000	450 000	480 000	540 000	600 000
5. 1800-rpm, four-flow	....	....	....	....	520 000	560 000	600 000	680 000	760 000
6. 1800-rpm, six-flow	....	....	....	....	....	....	....	840 000	920 000
5. Special oil coolers (price for two)									
a For 100 F water temperature	21 000	24 000	27 000	30 000	33 000	36 000	39 000	45 000	49 500
b For 105 F water temperature or 30% oversize cooler	57 000	61 500	66 000	70 500	75 000	79 500	84 000	90 000	96 000
c For 300 psi coolers	12 000	13 000	14 000	15 000	16 000	17 000	18 000	20 000	22 000
d For ¾-inch or ⅞-inch diameter tubes	7 500	7 500	7 500	9 000	9 000	9 000	9 000	12 000	12 000
e For stainless steel tubes (smooth)	48 000	51 000	51 000	54 000	54 000	57 000	57 000	60 000	60 000
f For aluminum-brass or arsenical copper tubes	5 000	5 500	6 000	6 500	7 000	7 500	8 000	9 000	10 000
g Deduct for one cooler and transfer valve	31 500	33 750	36 000	38 250	40 500	42 750	45 000	48 000	51 000
①6. Accessories									
a Oil for filling lubrication system	30 000	35 000	40 000	45 000	50 000	55 000	60 000	70 000	80 000
b Hangers for oil and gland steam piping (piping analysis not included)	16 000	20 000	24 000	28 000	32 000	36 000	40 000	45 000	46 000

① Changed since previous issue.

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Steam Turbine Division, Philadelphia, Pa. 19113
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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Table D: Special Turbine Equipment, Features and Requirements—800,000 to 1,500,000 Kw
Prices in Dollars

	Turbine Rating, Mw							
	800	900	1000	1100	1200	1300	1400	1500
1. Technical Direction of Installation (Deduct for omission)②	$344 000	$ 380 000	$ 416 000	$ 452 000	$ 488 000	$ 524 000	$ 560 000	$ 596 000
2. Turbine tests								
a Turbine acceptance test in field at Purchaser's request③	230 000	245 000	260 000	270 000	280 000	290 000	300 000	310 000
b Turbine connections for Purchaser's test④	35 000	38 000	41 000	44 000	47 000	50 000	53 000	56 000
c Turbine connections for Purchaser's enthalpy drop tests⑤	5 000	5 600	6 200	6 800	7 400	8 000	8 600	9 200
3. Extractions								
a For each type auxiliary turbine application with steam from auxiliary turbine entering into the feed-water heating cycle⑥								
1. Does not re-admit to main turbine	100 000	110 000	110 000	120 000	120 000	130 000	130 000	140 000
2. Re-admits to main turbine	230 000	250 000	270 000	290 000	310 000	330 000	350 000	370 000
b For other uncontrolled extraction⑦	72 000	81 000	90 000	99 000	108 000	117 000	126 000	135 000
c Single-automatic extraction for condensing units	← Refer to Factory →							
d Double-automatic extraction for condensing units	← Refer to Factory →							
4. Side exhaust openings⑧								
a Below Floor line								
1. 3600-rpm, double-flow	....	....	....	....	....	....	....	....
2. 3600-rpm, four-flow	440 000	....	....	....	....	....	....	....
3. 3600-rpm, six-flow	680 000	640 000	700 000	....	....	....	....	....
b Above Floor line								
1. 3600-rpm, double-flow	....	....	....	....	....	....	....	....
2. 3600-rpm, four-flow	580 000	....	....	....	....	....	....	....
3. 3600-rpm, six-flow	760 000	830 000	910 000	....	....	....	....	....
4. 1800-rpm, double-flow	660 000	....	....	....	....	....	....	....
5. 1800-rpm, four-flow	840 000	920 000	1000 000	....	....	....	....	....
6. 1800-rpm, six-flow	1000 000	1080 000	1160 000	1240 000	1320 000	1400 000	1480 000	1560 000
5. Special oil coolers (price for two)								
a For 100 F water temperature	54 000	58 500	63 000	66 000	69 000	72 000	75 000	78 000
b For 105 F water temperature or 30% oversize cooler	102 000	108 000	114 000	120 000	126 000	132 000	138 000	144 000
c For 300 psi coolers	23 000	24 000	25 000	26 000	27 000	28 000	29 000	30 000
d For ¾-inch or ⅝-inch diameter tubes	15 000	15 000	18 000	18 000	21 000	21 000	24 000	24 000
e For stainless steel tubes (smooth)	66 000	66 000	72 000	72 000	78 000	78 000	84 000	84 000
f For aluminum-brass or arsenical copper tubes	11 000	12 000	13 000	14 000	15 000	16 000	17 000	18 000
g Deduct for one cooler and transfer valve	54 000	57 000	60 000	63 000	66 000	69 000	72 000	75 000
①6. Accessories								
a Oil for filling lubrication system	90 000	100 000	110 000	120 000	130 000	140 000	150 000	160 000
b Hangers for oil and gland steam piping (piping analysis not included)	49 000	52 000	55 000	58 000	61 000	64 000	67 000	70 000

① Changed since previous issue.

For foot-notes, refer to page 28.

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Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Table D: Special Turbine Equipment, Features and Requirements—200,000 to 700,000 Kw, Continued
Prices in Dollars

	Turbine Rating Mw 200	250	300	350	400	450	500	600	700
f Foundation bolts	$ 6 400	$ 7 000	$ 7 600	$ 8 200	$ 8 800	$ 9 400	$ 10 000	$ 11 200	$ 12 400
g Blanket-type insulation(5)									
1. Tandem-compound units	32 000	36 000	40 000	44 000	48 000	52 000	56 000	64 000	72 000
2. Cross-compound units	43 000	52 000	56 000	60 000	64 000	68 000	72 000	80 000	88 000
h Omission of metal lagging Deduct(10)	28 000	32 000	36 000	40 000	44 000	48 000	52 000	55 000	58 000
j Totally enclosed motors for turning gear, ac turning gear oil pump, ac hydrogen seal oil back-up pump, dc emergency bearing oil pump, vapor extractor and gland condenser blowers(11)	4 200	4 800	5 400	6 000	6 600	7 200	7 800	8 800	9 800
k Lagging support sills	2 400	2 400	2 600	2 600	2 800	2 800	3 000	3 200	3 400
l Turbine shaft sealing systems									
1. Additional gland condenser(13)	46 000	50 000	54 000	58 000	62 000	66 000	70 000	75 600	81 200
2. Additional motor-driven blower for gland condenser(13)	4 200	4 500	4 800	5 100	5 400	5 700	6 000	6 600	7 200
3. Gland condenser for 135 F water temperature in lieu of standard 125 F	4 000	4 350	4 700	5 050	5 400	5 750	6 100	6 800	7 500
4. Gland condenser for 150 F water temperature in lieu of standard 125 F(14)	23 200	24 000	24 800	25 600	26 400	27 200	28 000	29 600	31 200
5. Motor-driven blower for gland condenser designed for 1.0 psig discharge pressure in lieu of standard 0.25 psig	1 700	1 800	1 900	2 000	2 100	2 200	2 300	2 400	2 600

Table D: Special Turbine Equipment, Features and Requirements—800,000 to 1,500,000 Kw, Continued
Prices in Dollars

	Turbine Rating, Mw 800	900	1000	1100	1200	1300	1400	1500
f Foundation bolts	$ 13 600	$ 14 800	$ 16 000	$ 17 200	$ 18 400	$ 19 600	$ 20 800	$ 22 000
g Blanket-type insulation(5)								
1. Tandem-compound units	80 000	88 000	96 000	....	....	....	....	....
2. Cross-compound units	96 000	104 000	112 000	120 000	128 000	136 000	144 000	152 000
h Omission of metal lagging Deduct(10)	61 000	64 000	67 000	70 000	73 000	76 000	79 000	82 000
j Totally enclosed motors for turning gear, ac turning gear oil pump, ac hydrogen seal oil back-up pump, dc emergency bearing oil pump, vapor extractor and gland condenser blower(11)	10 800	11 800	12 800	13 800	14 800	15 800	16 800	17 800
k Lagging support sills	3 600	3 800	4 000	4 200	4 400	4 600	4 800	5 000
l Turbine shaft sealing systems								
1. Additional gland condenser(13)	86 800	92 400	98 000	103 600	109 200	114 800	120 400	126 000
2. Additional motor-driven blower for gland condenser(13)	7 800	8 400	9 000	9 600	10 200	10 800	11 400	12 000
3. Gland condenser for 135 F water temperature in lieu of standard 125 F	8 200	8 900	9 600	10 300	11 000	11 700	12 400	13 100
4. Gland condenser for 150 F water temperature in lieu of standard 125 F(14)	32 800	34 400	36 000	37 600	39 200	40 800	42 400	44 000
5. Motor-driven blower for gland condenser designed for 1.0 psig discharge pressure in lieu of standard 0.25 psig	2 800	3 000	3 200	3 400	3 600	3 800	4 000	4 200

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Steam Turbine Generator Units

Condensing Reheat Double Flow 26-Inch Last Row Blades and Larger

Table E: Special Generator Equipment and Features—240,000 to 840,000 Kva
Prices in Dollars

	Generator Rating, Mva								
	240	300	360	420	480	540	600	720	840
1. Generator modifications									
a 0.80 power factor	$160 000	$200 000	$240 000	$280 000	$320 000	$360 000	$400 000	$480 000	$560 000
b 0.85 power factor	80 000	100 000	120 000	140 000	160 000	180 000	200 000	240 000	280 000
c 0.95 power factor (Deduct)	28 000	32 000	36 000	40 000	44 000	48 000	52 000	60 000	68 000
d 0.72 short-circuit ratio	370 000	410 000	450 000	490 000	530 000	570 000	610 000	690 000	[illegible]70 000
e 0.64 short-circuit ratio	150 000	170 000	190 000	210 000	230 000	250 000	270 000	310 000	[illegible]0 000
f 0.50 short-circuit ratio (Deduct)ⓢ	30 000	34 000	38 000	42 000	46 000	50 000	54 000	62 000	70 000
g Voltage range of plus or minus 5% within guaranteed temperature rise	60 000	70 000	80 000	90 000	100 000	110 000	120 000	140 000	160 000
2. Special generator coolers									
a Generator coolers									
1. For 300 psi	12 000	14 [illegible]	16 000	18 000	20 000	22 000	24 000	28 000	32 000
2. For aluminum-brass tubes – 16 BWG	6 400	[illegible]	7 200	7 600	8 000	8 400	8 800	9 600	10 400
3. For stainless-steel tubes – 18 BWG	36 000	36 000	40 000	42 000	44 000	46 000	48 000	52 000	56 000
b Cooling water 105 F within guaranteed temperature rise									
1. Tandem-compound units	117 400	124 200	131 000	137 800	145 000	152 200	159 200	173 200	187 200
2. Cross-compound units	207 600	214 400	221 200	228 000	234 800	241 600	248 400	262 000	275 600
3. Accessories									
a Bushing current transformer (Add or Deduct for each)	1 700	1 900	2 100	2 300	2 500	2 700	2 900	3 300	3 700
b Generator neutral enclosure	14 800	18 400	22 000	25 600	29 200	32 800	36 400	43 600	50 800
c Neutral grounding equipmentⓢ	9 600	10 200	10 800	11 400	12 200	12 800	13 400	14 700	16 000
d Carriage for generator rotor removal	20 000	20 000	20 000	20 000	22 000	22 000	22 000	24 000	24 000

Table E: Special Generator Equipment and Features—960,000 to 1,800,000 Kva
Prices in Dollars

	Generator Rating, Mva							
	960	1080	1200	1320	1440	1560	1680	1800
1. Generator modifications								
a 0.80 power factor	$640 000	$720 000	$ 800 000	$ 880 000	$ 960 000	$1 040 000	$1 120 000	$1 200 000
b 0.85 power factor	320 000	360 000	400 000	440 000	480 000	520 000	560 000	600 000
c 0.95 power factor (Deduct)	76 000	84 000	92 000	100 000	108 000	116 000	124 000	132 000
d 0.72 short-circuit ratio	850 000	930 000	1 010 000	1 090 000	1 170 000	1 250 000	1 330 000	1 410 000
e 0.64 short-circuit ratio	390 000	430 000	470 000	510 000	550 000	590 000	630 000	670 000
f 0.50 short-circuit ratio (Deduct)ⓢ	78 000	86 000	94 000	102 000	110 000	118 000	126 000	134 000
g Voltage range of plus or minus 5% within guaranteed temperature rise	180 000	200 000	220 000	240 000	260 [illegible]	280 000	300 000	320 000
2. Special generator coolers								
a Generator coolers								
1. For 300 psi	36 000	40 000	44 000	48 000	52 000	56 000	60 000	64 000
2. For aluminum-brass tubes – 16 BWG	11 200	12 000	12 800	13 600	14 400	15 200	16 000	16 800
3. For stainless-steel tubes – 18 BWG	60 000	64 000	68 000	72 000	76 000	80 000	84 000	88 000
b Cooling water 105 F within guaranteed temperature rise								
1. Tandem-compound units	201 200	221 200	241 200	261 200	281 200	301 200	321 200	....
2. Cross-compound units	290 000	304 400	318 400	332 400	346 400	360 400	374 400	388 400
3 Accessories								
a Bushing current transformer (Add or Deduct for each)	4 100	4 500	4 900	5 300	5 700	6 100	6 500	6 900
b Generator neutral enclosure	58 000	65 200	72 400	79 600	86 800	94 000	101 200	108 400
c Neutral grounding equipmentⓢ	17 200	18 600	19 800	21 000	22 400	23 600	25 000	26 200
d Carriage for generator rotor removal	26 000	26 000	26 000	28 000	28 000	30 000	30 000	30 000

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Table F: Special Excitation Equipment and Features—240,000 to 840,000 Kva
Prices in Dollars

	Generator Rating, Mva								
	240	300	360	420	480	540	600	720	840
1. Excitation speed of response[17]									
a For tandem-compound units									
1. Response ratio 1.0	$ 27 600	$ 31 200	$ 34 800	$ 38 400	$ 42 000	$ 46 000	$ 49 800	$ 57 400	$ 65 000
2. Response ratio 1.5	60 800	68 400	76 000	84 000	92 000	100 000	108 000	123 600	139 200
3. Response ratio 2.0	100 000	112 000	124 000	136 000	148 000	160 000	172 000	196 000	220 000
4. Response ratio 2.5	....	152 000	168 000	184 000	200 000	216 000	232 000	264 000	296 000
5. Response ratio 3.0	....	194 000	219 000	234 000	254 000	274 000	294 000	334 000	374 000
6. Response ratio 3.5	....	236 000	260 000	284 000	308 000	332 000	356 000	404 000	452 000
b For cross-compound units. Two shaft- or motor-driven exciters									
1. Response ratio 1.0	40 000	43 200	47 200	51 200	55 200	58 800	62 400	69 600	76 800
2. Response ratio 1.5	91 600	98 800	106 000	113 600	121 600	129 200	136 800	152 000	168 000
3. Response ratio 2.0	152 000	164 000	176 000	188 000	200 000	212 000	224 000	248 000	272 000
4. Response ratio 2.5	....	....	....	....	....	....	304 000	336 000	368 000
5. Response ratio 3.0	....	....	....	....	....	....	388 000	428 000	468 000
6. Response ratio 3.5	....	....	....	....	....	....	472 000	520 000	568 000
2. High initial response									
a For tandem-compound units with									
1. Response ratio 0.5	....	....	340 000	340 000	340 000	360 000	380 000	420 000	460 000
2. Response ratio 1.0	....	....	309 000	305 000	301 000	318 000	338 000	371 000	407 000
3. Response ratio 1.5	....	....	278 000	270 000	262 000	276 000	292 000	322 000	354 000
4. Response ratio 2.0	....	....	246 000	234 000	222 000	235 000	248 000	274 000	300 000
5. Response ratio 2.5	....	....	216 000	200 000	184 000	193 000	203 000	223 000	243 000
6. Response ratio 3.0	....	....	186 000	166 000	146 000	151 000	158 000	172 000	186 000
7. Response ratio 3.5	....	....	155 000	131 000	107 000	110 500	114 000	121 000	128 000
b For cross-compound units with									
1. Response ratio 0.5	....	....	....	....	....	....	....	680 000	680 000
2. Response ratio 1.0	....	....	....	....	....	....	....	617 000	609 000
3. Response ratio 1.5	....	....	....	....	....	....	....	554 000	538 000
4. Response ratio 2.0	....	....	....	....	....	....	....	492 000	468 000
5. Response ratio 2.5	....	....	....	....	....	....	....	431 000	399 000
6. Response ratio 3.0	....	....	....	....	....	....	....	370 000	330 000
7. Response ratio 3.5	....	....	....	....	....	....	....	310 000	262 000

Table F: Special Excitation Equipment and Features—960,000 to 1,800,000 Kva
Prices in Dollars

	Generator Rating, Mva							
	960	1080	1200	1320	1440	1560	1680	1800
1. Excitation speed of response[17]								
a For tandem-compound units								
1. Response ratio 1.0	$ 72 800	$ 80 800	$ 88 800	$ 96 800	$104 800	$112 800	$120 800	$128 800
2. Response ratio 1.5	154 800	170 400	186 000	201 600	217 200	232 800	248 400	264 000
3. Response ratio 2.0	244 000	268 000	292 000	316 000	340 000	364 000	388 000	412 000
4. Response ratio 2.5	328 000	360 000	392 000	424 000	456 000	488 000	520 000	552 000
5. Response ratio 3.0	414 000	454 000	494 000	534 000	574 000	614 000	654 000	694 000
6. Response ratio 3.5	500 000	548 000	596 000	644 000	693 000	740 000	787 000	834 000
b For cross-compound units. Two shaft- or motor-driven exciters								
1. Response ratio 1.0	84 000	92 000	99 600	107 200	114 800	122 400	130 000	137 800
2. Response ratio 1.5	184 000	200 000	216 000	231 600	247 200	262 800	278 400	294 000
3. Response ratio 2.0	296 000	320 000	344 000	368 000	392 000	416 000	440 000	464 000
4. Response ratio 2.5	400 000	432 000	464 000	496 000	528 000	560 000	592 000	624 000
5. Response ratio 3.0	508 000	548 000	588 000	628 000	668 000	708 000	748 000	788 000
6. Response ratio 3.5	616 000	664 000	712 000	760 000	808 000	856 000	904 000	952 000
2. High initial response								
a For tandem-compound units with								
1. Response ratio 0.5	500 000	540 000	580 000	620 000	660 000	700 000	740 000	780 000
2. Response ratio 1.0	442 000	477 000	513 000	548 000	583 000	619 000	654 000	689 000
3. Response ratio 1.5	384 000	414 000	446 000	476 000	506 000	538 000	568 000	598 000
4. Response ratio 2.0	326 000	352 000	378 000	404 000	430 000	456 000	482 000	508 000
5. Response ratio 2.5	262 000	282 000	302 000	321 000	341 000	361 000	381 000	401 000
6. Response ratio 3.0	198 000	212 000	226 000	238 000	252 000	266 000	280 000	294 000
7. Response ratio 3.5	135 000	142 000	149 000	156 000	162 000	170 000	178 000	186 000
b For cross-compound units with								
1. Response ratio 0.5	680 000	720 000	760 000	800 000	840 000	880 000	920 000	960 000
2. Response ratio 1.0	601 000	637 000	672 000	707 000	743 000	778 000	813 000	849 000
3. Response ratio 1.5	522 000	554 000	584 000	614 000	646 000	676 000	706 000	738 000
4. Response ratio 2.0	444 000	470 000	496 000	522 000	548 000	574 000	600 000	626 000
5. Response ratio 2.5	367 000	387 000	407 000	426 000	446 000	466 000	485 000	505 000
6. Response ratio 3.0	290 000	304 000	318 000	330 000	344 000	358 000	370 000	384 000
7. Response ratio 3.5	214 000	221 000	228 000	235 000	242 000	249 000	256 000	263 000

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Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Table G: Weatherproofing of Turbine Generators—200,000 to 700,000 Kw
Prices in Dollars

	Turbine Rating, Mw								
	200	250	300	350	400	450	500	600	700
1. Weatherproof complete unit for normal temperaturesⒶ									
a. Tandem-compound	$ 96 000	$105 000	$105 000	$105 000	$112 000	$112 000	$112 000	$125 000	$125 000
b. Cross-compound	121 000	130 000	130 000	130 000	137 000	137 000	137 000	150 000	150 000
c. Tandem-compound (Rollaway)	216 000	225 000	225 000	225 000	232 000	232 000	232 000	245 000	245 000
d. Cross-compound (Rollaway)	241 000	250 000	250 000	250 000	257 000	257 000	257 000	270 000	270 000
2. Weatherproof complete unit for sub-normal temperaturesⒷ									
a. Tandem-compound	116 000	125 000	125 000	125 000	135 000	135 000	135 000	145 000	145 000
b. Cross-compound	140 000	150 000	150 000	150 000	160 000	160 000	160 000	170 000	170 000
c. Tandem-compound (Rollaway)	236 000	245 000	245 000	245 000	255 000	255 000	255 000	265 000	265 000
d. Cross-compound (Rollaway)	260 000	270 000	270 000	270 000	280 000	280 000	280 000	290 000	290 000
3. Turbine walk-in enclosureⒸ	40 000	40 000	40 000	40 000	44 000	44 000	44 000	48 000	48 000
4. Weatherproofed enclosure over front pedestalⒹ									
a. With limited walk-around space	32 000	33 000	34 000	35 000	36 000	37 000	38 000	40 000	42 000
b. With walk-around space, plus additional space for panels	44 000	45 000	46 000	47 000	48 000	49 000	50 000	52 000	54 000

Table G: Weatherproofing of Turbine Generators—800,000 to 1,500,000 Kw
Prices in Dollars

	Turbine Rating, Mw							
	800	900	1000	1100	1200	1300	1400	1500
1. Weatherproof complete unit for normal temperaturesⒶ								
a. Tandem-compound	$125 000	$135 000	$135 000	$150 000	$150 000	$150 000	$150 000	$150 000
b. Cross-compound	150 000	160 000	160 000	160 000	175 000	175 000	175 000	180 000
c. Tandem-compound (Rollaway)	245 000	255 000	255 000	255 000	270 000	270 000	270 000	275 000
d. Cross-compound (Rollaway)	275 000	280 000	280 000	280 000	295 000	295 000	295 000	300 000
2. Weatherproof complete unit for sub-normal temperaturesⒷ								
a. Tandem-compound	145 000	155 000	155 000	155 000	170 000	170 000	170 000	175 000
b. Cross-compound	170 000	180 000	180 000	180 000	195 000	195 000	195 000	200 000
c. Tandem-compound (Rollaway)	265 000	275 000	275 000	275 000	290 000	290 000	290 000	295 000
d. Cross-compound (Rollaway)	290 000	300 000	300 000	300 000	315 000	315 000	315 000	300 000
3. Turbine walk-in enclosureⒸ	52 000	52 000	52 000	56 000	56 000	56 000	56 000	56 000
4. Weatherproofed enclosure over front pedestalⒹ								
a. With limited walk-around space	44 000	46 000	48 000	50 000	52 000	54 000	....	....
b. With walk-around space, plus additional space for panels	56 000	58 000	60 000	62 000	64 000	66 000	....	....

For foot-notes, refer to page 28.

No change since previous issue.

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October 30, 1974
Supersedes Price List 1252, dated July 1, 1974
E, C/1683/PL

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Foot-Notes
For Pages 22 through 27 inclusive

② A Westinghouse engineer must be employed to direct the installation. This deduction may be made if the Purchaser desires to hire the Westinghouse engineer at the prevailing hourly rate.

③ Purchaser's and Westinghouse's representatives will jointly plan test procedure and instrumentation. Calibrated instruments and devices required for the test will be furnished by Westinghouse (to be returned). Westinghouse will provide engineering direction of test installation and the running of the test. Westinghouse will calculate the test results from the test data and furnish a complete test report to the Purchaser.

Includes turbine connections for the test instrumentation.

The Purchaser will make the unit available at the loads and steam conditions necessary for the test and will provide material and labor for installation of the test instrumentation, and personnel to read and record test data.

①④ Pressure connections in low pressure inlet; Pressure connections for LP extractions; basket tips in LP exhaust; orifices and thermocouple wells in steam seal piping system.

⑤ Two thermocouple wells and pressure connection for low-pressure inlet.

⑥ The main unit steam seal regulating valves and gland steam condenser will (if requested by Purchaser) be sized to handle the auxiliary turbine applications.

⑦ When uncontrolled extraction steam is required over and above normal feedwater heating and auxiliary turbine applications (where required), the prices listed are to be multiplied by the nearest percent extraction determined by the formula:

Fossil Units

$$\frac{\text{Additional extraction flow} \times 100}{\text{Throttle flow at guaranteed output}} - 6\%$$

Nuclear Units

$$\frac{\text{Additional extraction flow} \times 100}{\text{Throttle flow at guaranteed output}}$$

The uncontrolled extraction steam need not re-enter the feedheating cycle.

The price includes protection to prevent overloading the turbine parts when the extraction is shut off.

⑧ Side-exhaust units will have the same heat rates as downward exhaust.

⑨ Complete blanket insulation over high temperature turbine parts instead of standard block and plastic.

⑩ Includes omission of the enclosure over the HP and IP turbine(s), inlet bends and inlet valves. The front pedestal, and low pressure turbine cylinder foot will be enclosed.

⑪ The A-c turning gear oil pump motor is available encapsulated if it is over 40 HP.

⑫ Includes standard tube materials, one motor-driven blower, one manual inlet valve, level alarm and two motor operated isolating valves.

⑬ Includes piping, manual valve, and two check valves.

⑭ Includes two exhaust blowers.

⑮ No extrapolation for SCR below 0.50.

⑯ Neutral grounding equipment includes distribution type neutral transformer and secondary resistor contained in a cubicle with sealing bushing and connection.

⑰ Base response ratio is 0.5. The definitions of "excitation system voltage response" and "excitation system voltage response ratio" are presented in IEEE Standard 421-1972.

①⑱ Includes weatherproofing of front pedestal; weatherproofing of turbine enclosure, including enclosure over control valves and cylinder-mounted intercept valves; weatherproofing of generator enclosure; and weatherproofing of exciter enclosure. In cases where the turbine employs external crossover pipes, their insulation will be covered. The turning gear and bearing pedestal between turbine exhaust hood and generator will be covered by a weatherproof enclosure.

Rollaway enclosure over turbine casing area can be provided instead of weatherproof turbine enclosure if desired. Enclosure designed in detachable sections, with necessary vents, doors, rollers, and hardware. Rails and supports in foundation are to be furnished by Purchaser.

The shaft-driven exciter will be covered with a weatherproof sheet-metal enclosure, including lighting, cooling, and a heater, but not insulated.

All turbine and generator motors will be furnished with space heaters where available and are the totally enclosed type except the turning gear motor, which is adequately protected by the turbine lagging and therefore is of the open drip-proof type. If the oil reservoir, E-H fluid reservoir, stop valves, intercept valves, hydrogen-seal oil unit and control panel, gas manifold and excitation cubicles are exposed to the elements they will be weather-proofed and heaters will be provided in the reservoirs. A price deduction for the omission of weatherproofing these items and for the omission of the reservoir heaters will not be made.

The E-H fluid lines will be designed, including Trace Heating, for an ambient temperature of 0 F with an assumed wind velocity of 25 MPH maximum. Westinghouse will provide the Trace Heating Equipment. Installation to be done by others.

If standard open motors on the oil reservoir are desired, a price deduction will be made.

Normal temperatures are those where ambient temperature is not below 0 F.

①⑲ Sub normal temperatures are those where ambient temperature is from 0 F to −40 F.

Additional weatherproofing for subnormal temperatures includes fans for circulation of warm air, additional ventilation shutters in turbine generator enclosure and heating elements for exposed gages and instruments.

Rollaway enclosure over the turbine cylinder area as described in note ⑱ can be provided.

The E-H fluid lines will be designed, including Trace Heating, for an ambient temperature of 0 F with an assumed wind velocity of 25 MPH. Westinghouse will provide the Trace Heating Equipment. Installation to be done by others.

⑳ The turbine walk-in enclosure consists of a lighted and ventilated sheet-metal enclosure over the turbine front end. The enclosure extends from about four feet in front of the turbine pedestal back to the main section of enclosure. There is a door on each side. No insulation or heating is provided in the enclosure. The turbine enclosure will consist of weatherproofed, sheet-metal lagging from the turbine walk-in enclosure over the high-pressure and intermediate-pressure cylinders to the governor end of the exhaust hood. The weatherproofed enclosure over the turning gear and exciter will remain unchanged.

㉑ a Weatherproofed sheet-metal enclosure with approximately three feet of walking space. Includes vents and lighting, but no insulation or heating; has removable sections to facilitate maintenance.

When rollaway house is used over turbine casing area, a rollaway house of approximately the same size as this weatherproofed enclosure can be provided over turbine front pedestal, instead of the weatherproofed enclosure, for the same price addition.

b Weatherproofed sheet-metal enclosure with at least three feet of walking space around the front pedestal, plus additional width to provide space for location of start-up and/or turbine supervisory instrument panels. Includes vents and lighting, but no insulation or heating; has removable sections to facilitate maintenance.

When rollaway house is used over turbine casing area, a rollaway house of approximately the same size as this weatherproofed enclosure can be provided over turbine front pedestal, instead of the weatherproofed enclosure.

① Changed or added since previous issue.

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Westinghouse

Steam Turbine Generator Units

Condensing Reheat Double Flow 25-Inch Last Row Blades and Larger

Table H: Special Accessories and Requirements, Turbines

	Price Addition
1. Electro-hydraulic control system	
a Remote set of valve position setpoint	$ 1,000
b Operator push button adjustment of throttle pressure limits	1,000
c Operator set Hi-Lo limit on load reference	1,000
d Indicator lamps – not push button	400
e Relay contact output (mercury wetted)	475
f Temperature switch to measure bulk E-H fluid	120
g High pressure header switches (high and low)	240
h Test solenoid for testing auto-start of auxiliary fluid pump	600
①i Two thermostatically controlled valves, two isolated valves, & strainer, for E-H fluid heat exchanger	1,000
j Reservoir heater – E-H	3,600
k Special loading rates for load rate selector	1,800
l Spare magnetic pickup on pulse wheel	1,000
m Spare E-H fluid supply pump	520
n Fluid for E-H system	8,000
o Additional length of cable between E-H panel and controller cabinet – per 10 foot length	600
①p Deletion of E-H fluid line trace heating ... Deduct	8,000
2. Solenoid actuation for motor pump test valves (in lieu of manual valves,) per valve	450
3. Gland systems	
a Deduct for omission of motor operated bypass and shut-off valves around main and spillover regulators	6,000
b Motor-operated butterfly discharge valve for isolation of exhauster blower, per valve	2,200
c Additional manual butterfly discharge valve for isolation of exhauster blower	500
d Gland condenser water supply design pressure for each 100 psig or fraction thereof above maximum standard of 400 psig	4,000
4. Special motor requirements	
a 4160 volt main auxiliary oil pump motor	6,200
b 2300 volt auxiliary oil pump motors	1,800
c Spaceheaters – turbine and generator motors, per unit	2,000
d Space heater for motor and box for motor-operated valves, per valve	150
e Delete d-c motor starter for emergency oil pump motor – Deduct	1,120
f D-c motors to accommodate voltages below 10% of rated voltage.	
1. Indoor units (ODP Motors)	
a Bearing oil pump motor	1,500
b Seal oil pump motor	1,000
2. Outdoor units (TEFC Motors)	
a Bearing oil pump motor	2,500
b Seal oil pump motor	1,000
5. Separate vibration trip relay and detector	3,000
6. Temperature trip relay	6,000
7a Differential expansion trip relay and detector	13,000
b Provisions for future mounting of above	$ 600
8. Speed recorder	2,400
9. Electric speed indicator	500
10. Milliammeter	500
11. Electric position transmitter	1,050
12. Electric position receiver	690
13. Extra shaft vibrometer pickup	1,600
14. Extra vibration recorder	3,600
15. Extra temperature recorder	3,600
16. Supervisory instrument cabinet	
a Tandem-compound unit	13,000
b Cross-compound unit	16,000
17. Turning gear control panel, per shaft②	1,340
18. Start up panel, indoor③	
a Tandem-compound unit	22,000
b Cross-compound unit	24,000
19. Type W switch	260
20. Limit switch	
a 1 N.O. and 1 N.C. contacts	230
b 2 N.O. and 2 N.C. contacts	310
c 3 N.O. and 3 N.C. contacts	390
d Provision for future mounting	140
21a Pressure switch	230
b Differential pressure switch	920
c Provision for future mounting	140
22. Indicator light	40
23. Gauges	
a Direct reading	160
b Pneumatic	
1. Transmitter	760
2. Receiver	160
c Electric	
1. Transmitter	1,100
2. Receiver	500
24. Additional pressure tap with nipple and shut off valve	
a Turbine cylinder – each	2,700
b Other – each	500
25. Temperature detection devices	
a Thermocouple or thermostat in bearing oil drain lines	120
b Thermocouple in bearing metal	340
c Exhaust hood thermostats	
1. With one alarm contact	230
2. With two alarm contact	350
d Thermocouple in cylinder, bolt or flange, or valve body or bonnet	460
e Two or three element thermocouple in lieu of standard single element	120
f Extra thermocouple well	120
g Platinum in lieu of conventional RTD's, each	150
h Indicating thermometers (dial)	
1. No alarm contact	320
2. With alarm contact	400
26 Additional float type oil level alarm (one is standard)	700
27. Larger terminal boxes on turbine-generator	600
28. Sliding-link type terminal boards, turbine	8,000
29. Steel wrench cabinet	2,500
30. Temporary blowdown covers and valve seat blanking plates for steam blowdown	
a Non-reheat, per set	$ 8,000
b Single reheat, per set	22,000
c Double reheat, per set	38,000
31. Temporary blowdown covers and valve seat blanking plates for acid wash and/or steam blowdown.	
a Non-reheat	10,000
b Single reheat	27,500
c Double reheat	46,000
32a Electric oil reservoir heater (up to 30 Kw)	3,600
b Provisions for future mounting of above	1,600
33. Oil mist eliminator (motor-driven)	3,000
34. Reproducible copies of final drawings, polyester base diazo	
a In lieu of standard	3,700
b In addition to standard	6,500
35. 35 MM microfilm negatives	
a In lieu of prints of final drawings deduct	1,400
b In lieu of prints of all issues of drawings deduct	5,600
c In addition to prints of final drawings – add per set	1,400
d In addition to prints of all issues of drawings	5,600
36. Extra copies of instruction book, each	60
37. Appearance model (¼"=1')	
a Tandem-compound	3,500
b Cross-compound	4,500
38. Combined main turbine systems with Westinghouse furnished auxiliary turbine systems:④	
a Combined E-H fluid system – each auxiliary turbine	12,000
b Combined E-H fluid and lube oil system – each auxiliary turbine	50,000
c Steam seal piping between main unit and auxiliary turbine(s)	12,000
d Manual isolation valves in steam seal piping between main unit and auxiliary turbine(s)	5,000
39. Preparation or review of specific automation flow charts	60,000
40. Thrust load recorder⑤	21,000/ shaft
41. Mixed exhaust ends	200,000
42. Anti-motoring protection⑥	1,350
①43. Boxing for overseas shipment increase total price	2%

① Addition since previous issue.
For foot-notes, refer to page 30.

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Foot-Notes for Table H, Page 29

② Includes ammeter and switch for turning gear motor, switch for ac bearing oil pump motor, and signal lights.

③ Includes receiver-type steam pressure gages, (main, 1st stage, to reheater, from reheater, exhaust): Type W switch and lamps for turning gear motor, turbine oil pump motors and vapor extractor motor; indicators for standard turbine supervisory instruments. Panels for cross-compound units include additional supervisory indicators and turning gear motor switch and lamp.

④ a Includes increased capacity for the E-H fluid system components and the interconnecting piping from main unit to header connection points at each auxiliary turbine. Requires all valve hydraulic relays to be located at an elevation higher than E-H fluid tank to permit gravity drainage. E-H fluid not included.

b Includes increased capacity of the lube oil system components for the supply of lube oil to the auxiliary turbine and its driven auxiliary, and interconnecting oil piping from main unit to header connection points at the auxiliary units. Includes combined E-H fluid system for main unit and auxiliary turbine, where applicable, with features as described above. Requires auxiliary turbine(s) to be located at an elevation higher than main-unit lube oil tank to permit gravity drainage of oil. Lube oil and E-H fluid not included.

c Does not include isolating valves between main unit and auxiliary turbine(s).

⑤ Includes thrust load cells mounted in thrust bearing housing and recorder (mounted by Purchaser).

⑥ Includes SG-1 Relay, pressure switch, and differential pressure switch.

No change since previous issue.

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Steam Turbine Generator Units

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Table J: Special Accessories and Requirements, Generators

	Price Addition
Generator	
1. Two extra bottle connections on CO_2 or H_2 gas manifolds	$ 100
2. Deletion of hydrogen and CO_2 manifolds (Deduct)	720
3. Space heaters in H_2 control panel or excitation cubicles, per cubicle section	170
4. Dc motor starter for dc seal oil pump	1,600
5. Generator temperature indicator (not including leads or selector switches)	500
6. Hydrogen purity receiver gauge	600
7. Relay type annunciator	
a 12 or 14 point	2,000
b 30 point	5,000
8. Thermocouple or RTD in stator windings, and iron or coolant passage	120
9. Tube expander for H_2 cooler	80
10. Test equipment rental:	
a For high potential test after installation, per week	5,000
b Additional oscillograph rental, per week	2,000
11. Calibration of bushing current transformer, per CT per burden②	350
12. Stator winding cooling water system components	
a Spare deionizer with required piping valves and gages	15,000
b Isolation valves and associated piping to coolers	10,400
c Spare full-flow filter with required piping, valves and gages	12,600
d Immersion heater, thermostat and pressure switch	2,700
13. Sliding-link type terminal boards, generator only	5,000
14. Tests	
a Short factory test series③	300,000
b Long factory test series④	320,000
Excitation system and miscellaneous switchgear (prices are on a "per generator" basis)	
15. Line drop compensation	1,100
16. Power system stabilizing	
a F-7 supplemental signal	12,000
b F-V8 supplemental signal⑤	18,300
17. Position indicator for computer input	1,500
18a Interposing relays for excitation system operation on computer pulse control⑥	6,400
b Provision for future mounting of above with wiring, per set	1,000
19. Voltage regulator latching relays⑦	$1,280
20. Voltage matching equipment⑧	2,200
21. Dust-proof enclosure per cubicle section	3,740
22. Maximum volts/Hertz excitation limiter⑨	2,400
23. Loss of excitation relay	1,800
24. Base adjustor follower⑩	2,750
25. Portable stroboscope	1,100

No change since previous issue.

Foot-Notes for page 29

② Standard includes a two-point calibration, per ANSI standard burden B-2; this price applies per additional or special test burden.

③ Short factory test series includes running the generator at the factory and performing the following tests:
1. Open circuit saturation curve
2. Open circuit core loss curve
3. Short circuit loss curve
4. Synchronous impedance curve
5. Double frequency vibration
6. Voltage balance
7. Current balance
8. Phase sequence
9. Shaft voltage
10. Residual voltage
11. Hydrogen seal oil flow
12. Bearing and seal insulation test

④ Long factory test series includes the short factory test series plus:
1. Open delta saturation curve
2. TIF and harmonic analysis
3. Open circuit heat run
4. Short circuit heat run
5. Zero excitation heat run

⑤ Bias of voltage regulator so that during changes in frequency the excitation is regulated as a function of both voltage and frequency.

⑥ Latching or interposing relays to allow parallel computer/operator control of field breaker, transfer relay, dc voltage adjuster and ac voltage adjuster. Provides mode selection.

⑦ Latching to prevent regulator returning to manual control on battery supply interruption.

⑧ Matches generator terminal voltage to line voltage prior to connecting generator to line.

⑨ Voltage regulator bias by generator frequency to limit volts per Hertz in automatic mode and below 57 Hertz while off-line.

⑩ Continuous adjustment of dc regulator while operating on ac regulator so that a regulator transfer will not change excitation.

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Last Row Blades and Larger

New Information

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Subappendix AA 12.1.2

PROPOSAL DESCRIPTIVE LEAFLETS

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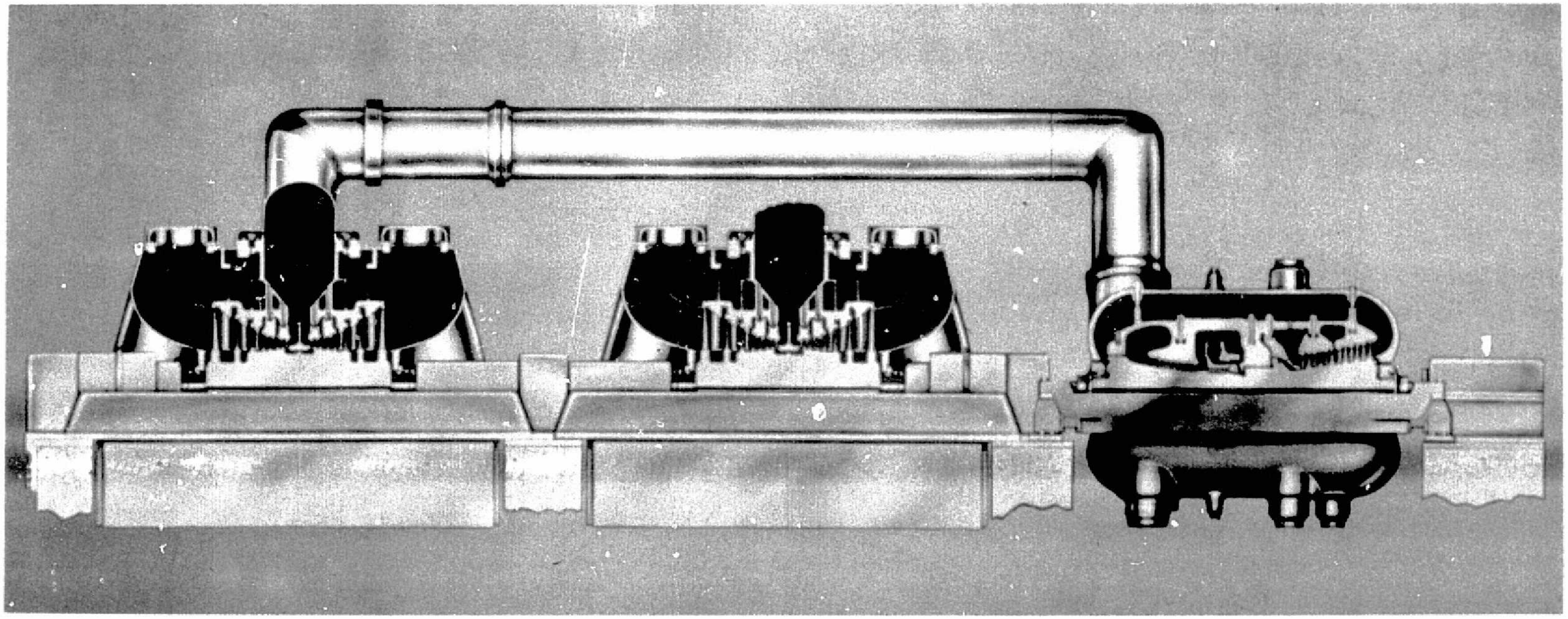
AA 12.1.2.1 500 MW Turbine-Generator Configurations

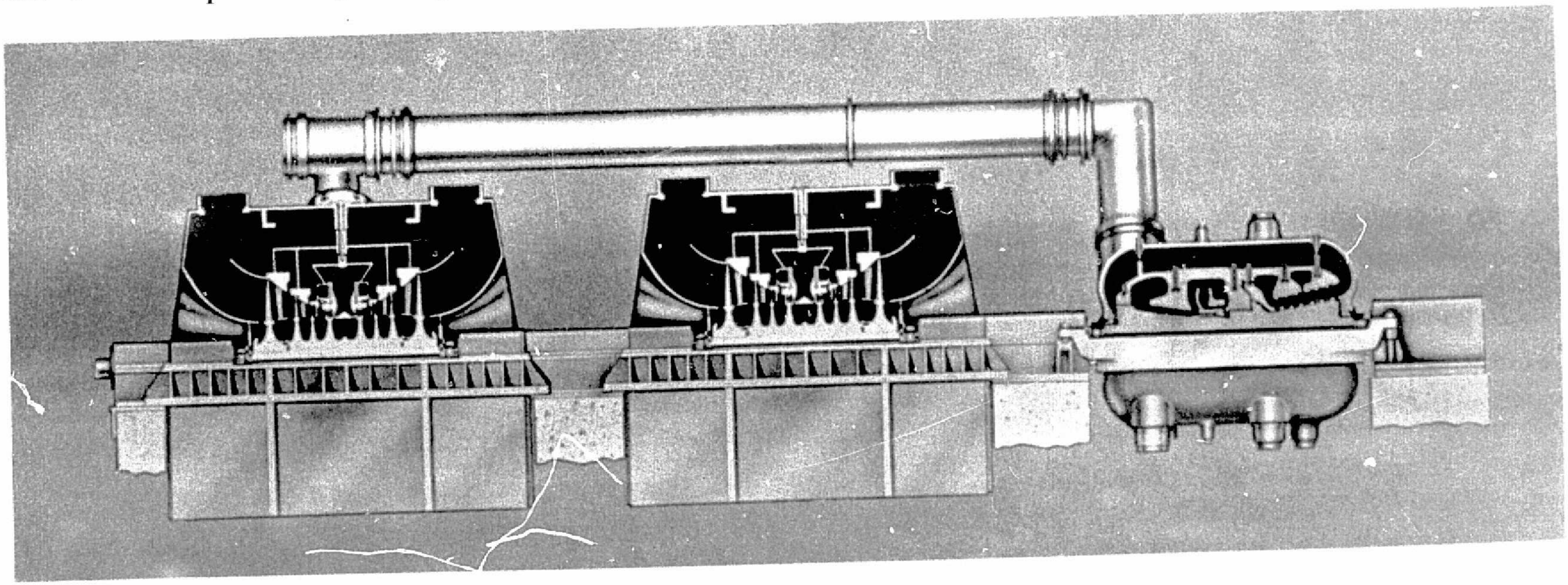
Tandem-Compound Quadruple-Flow Reheat Turbine



44-271-271

Longitudinal section of TC4F reheat turbine, 3600 rpm.

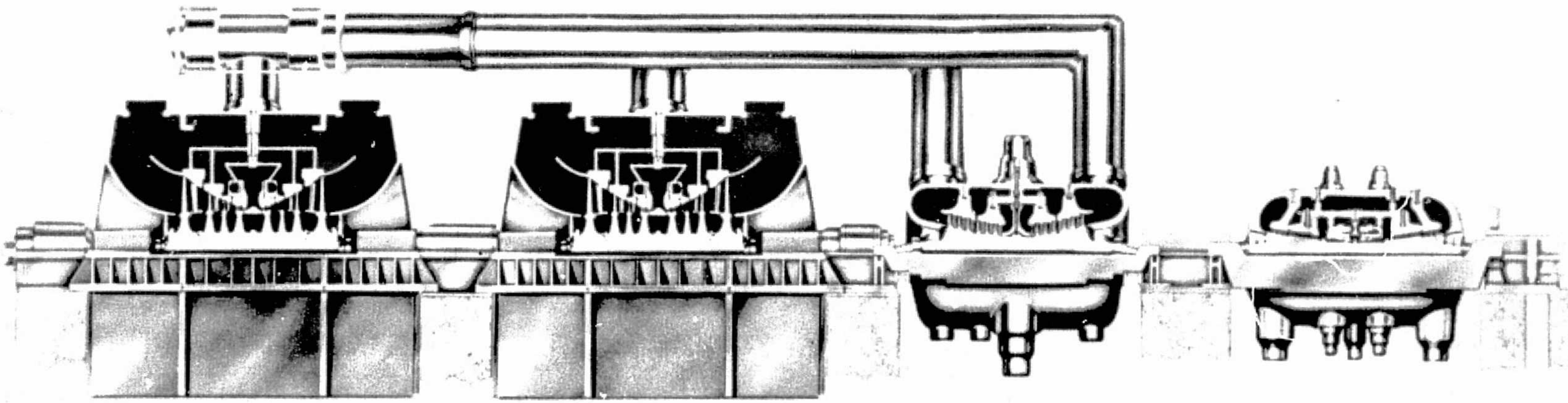
Tandem-Compound Quadruple-Flow Reheat Turbine



Longitudinal section of TC4F reheat turbine, 3600 rpm.

44-73-73

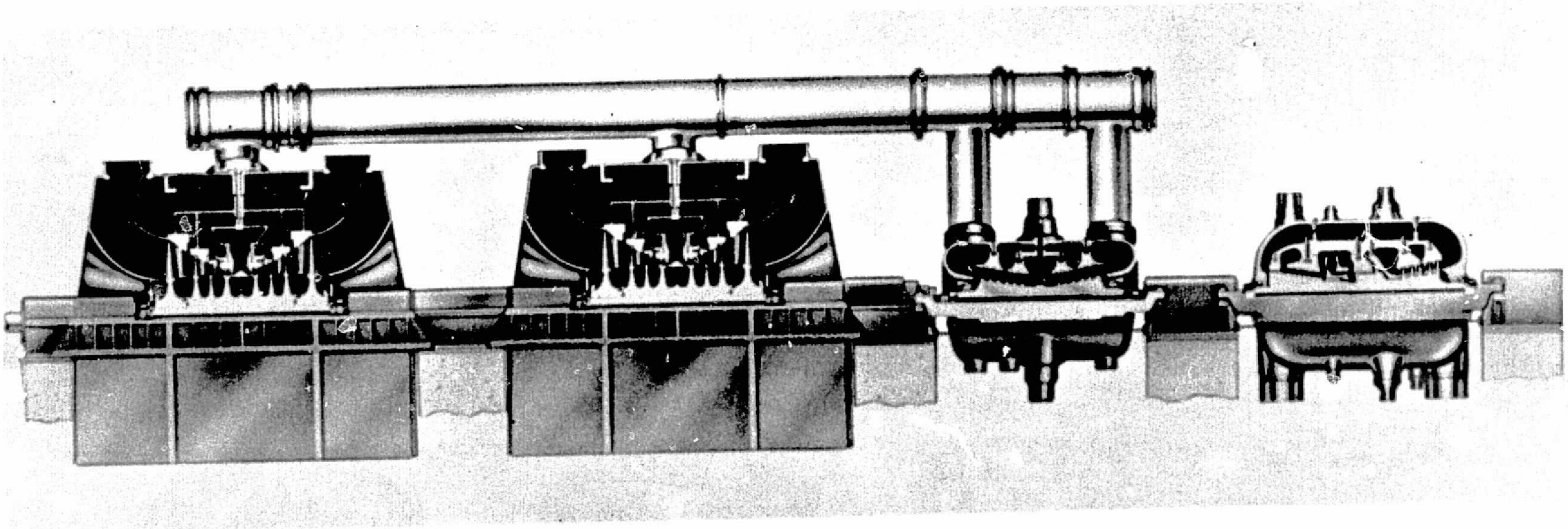
Tandem-Compound Quadruple-Flow Reheat Turbine



22-57-73-73

Longitudinal section of TC4F reheat turbine, 3600 rpm.

Tandem-Compound Quadruple-Flow Double Reheat Turbine



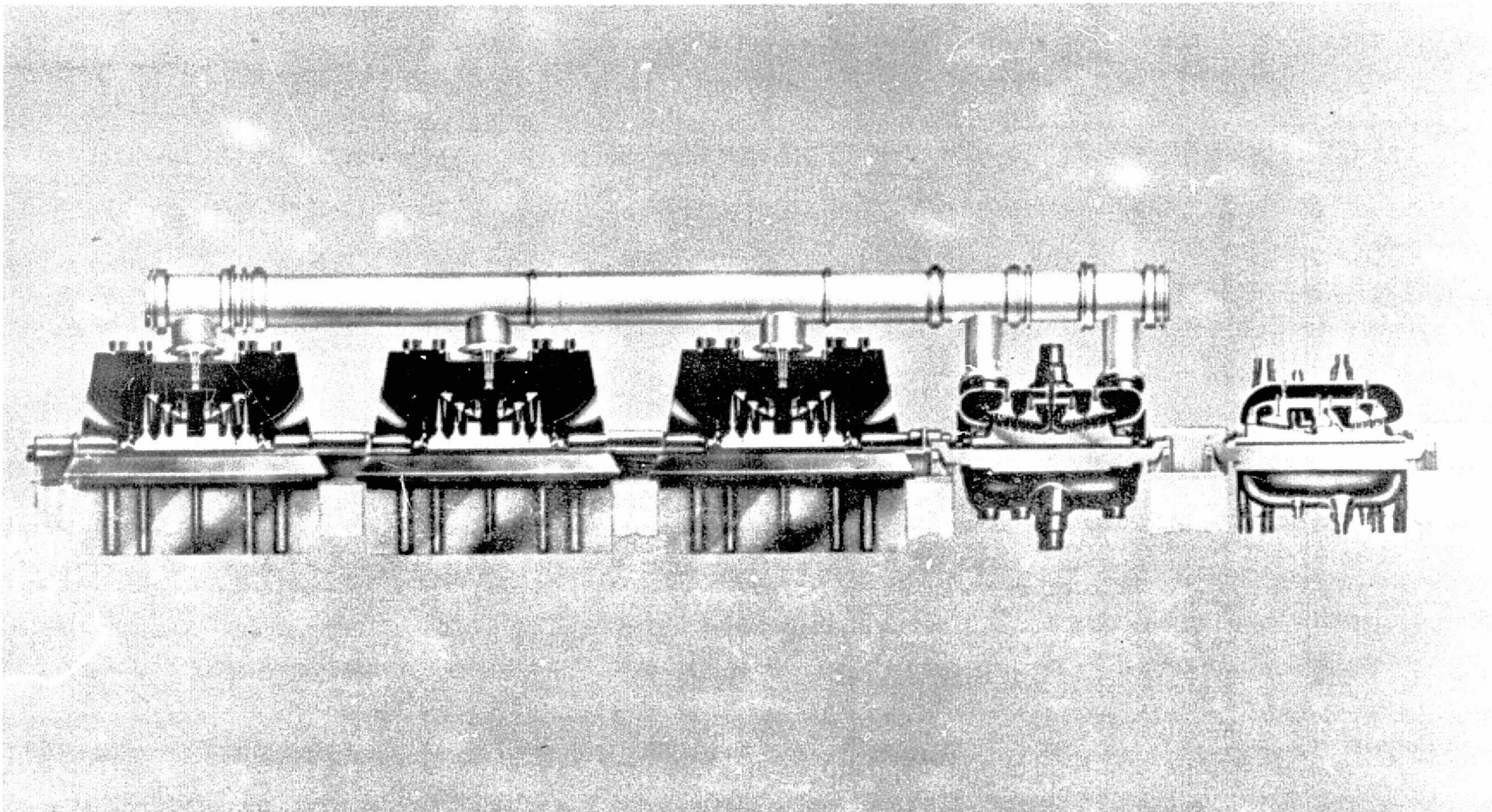
Longitudinal section of TC4F double reheat turbine, 3600 rpm.

46-57-73-73

Westinghouse

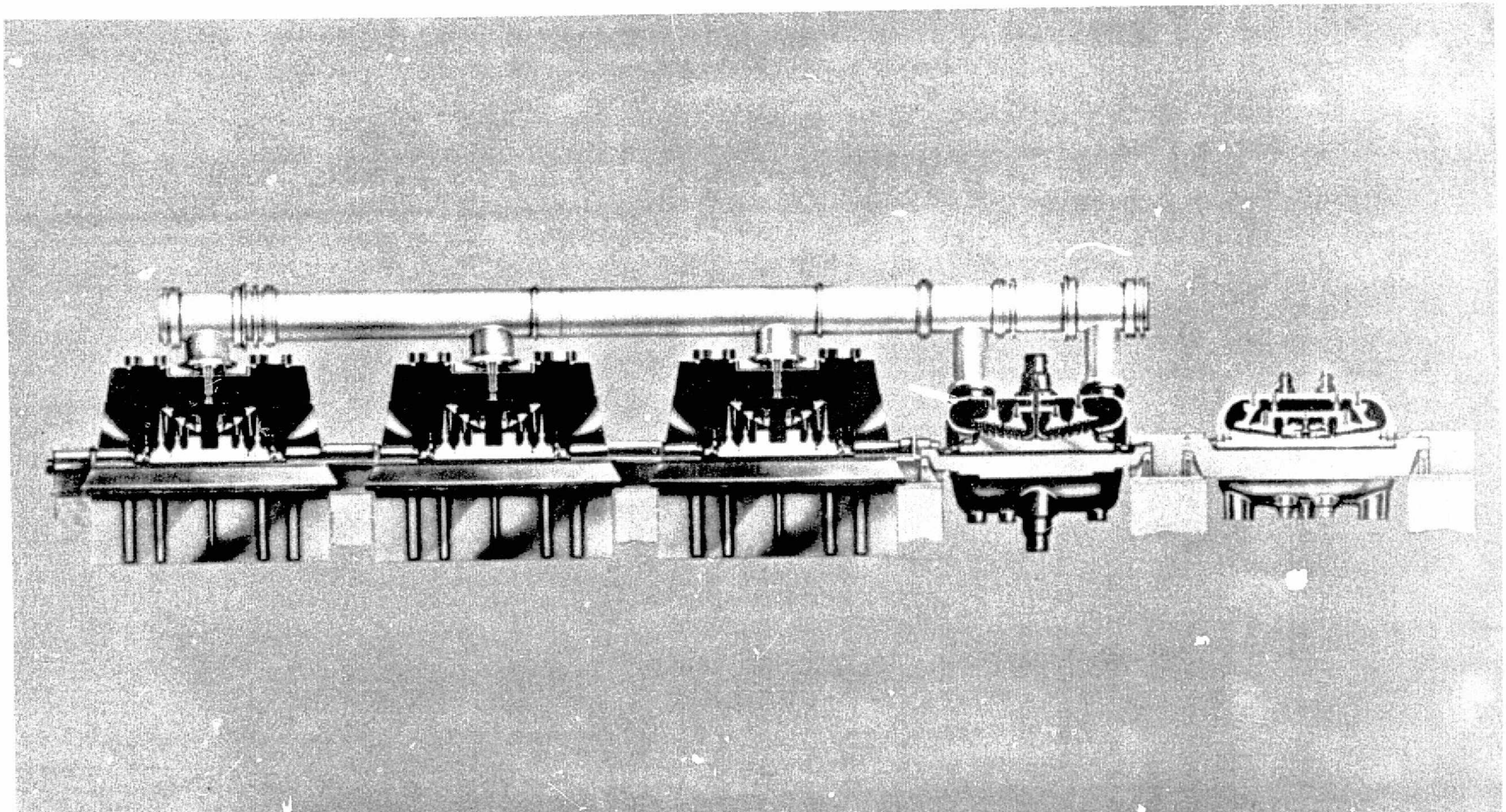
AA 12.1.2.2 900 MW Turbine-Generator Configurations

Tandem-Compound Six-Flow Double Reheat Turbine



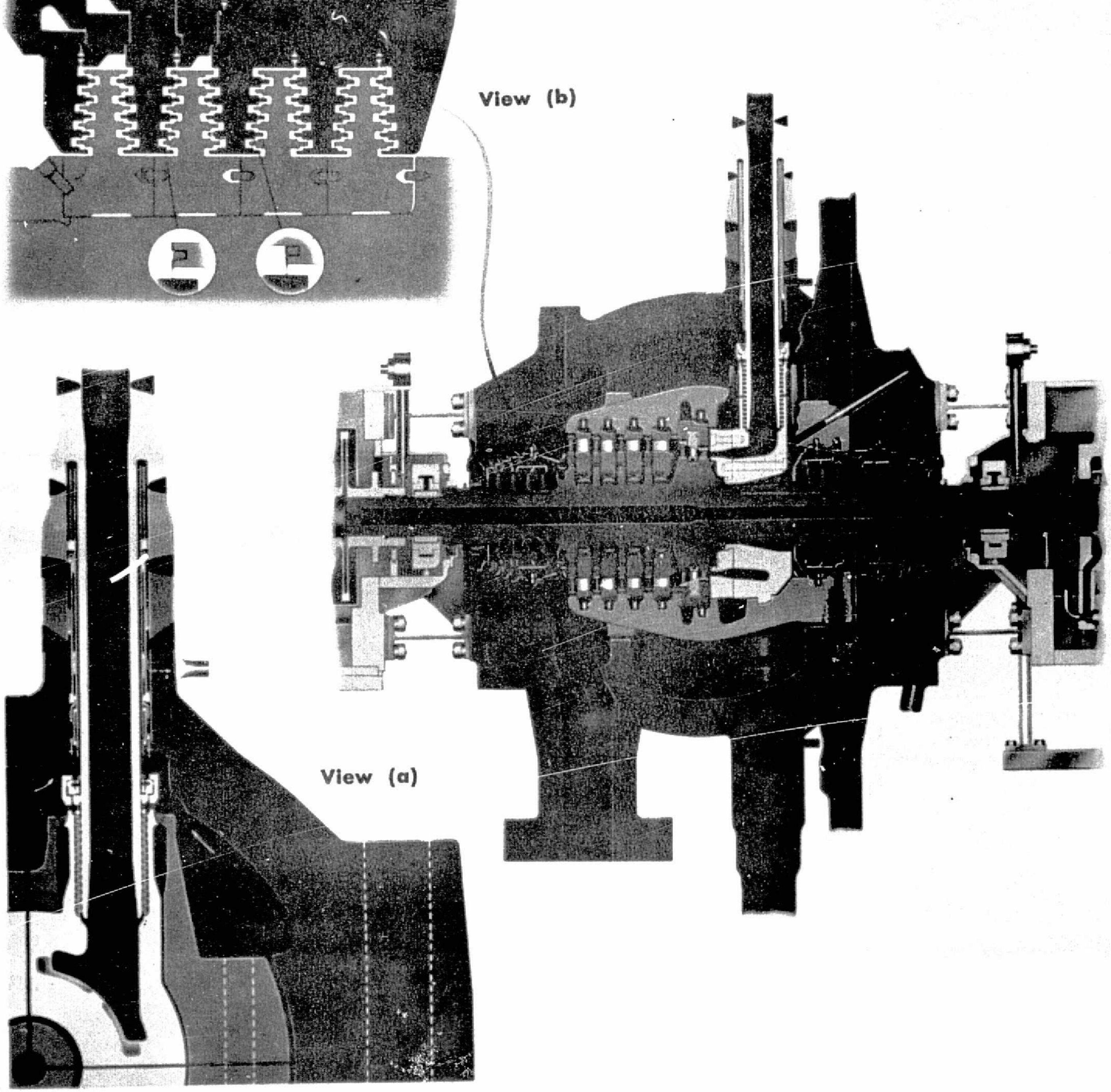
Longitudinal section of TC6F double reheat turbine, 3600 rpm.

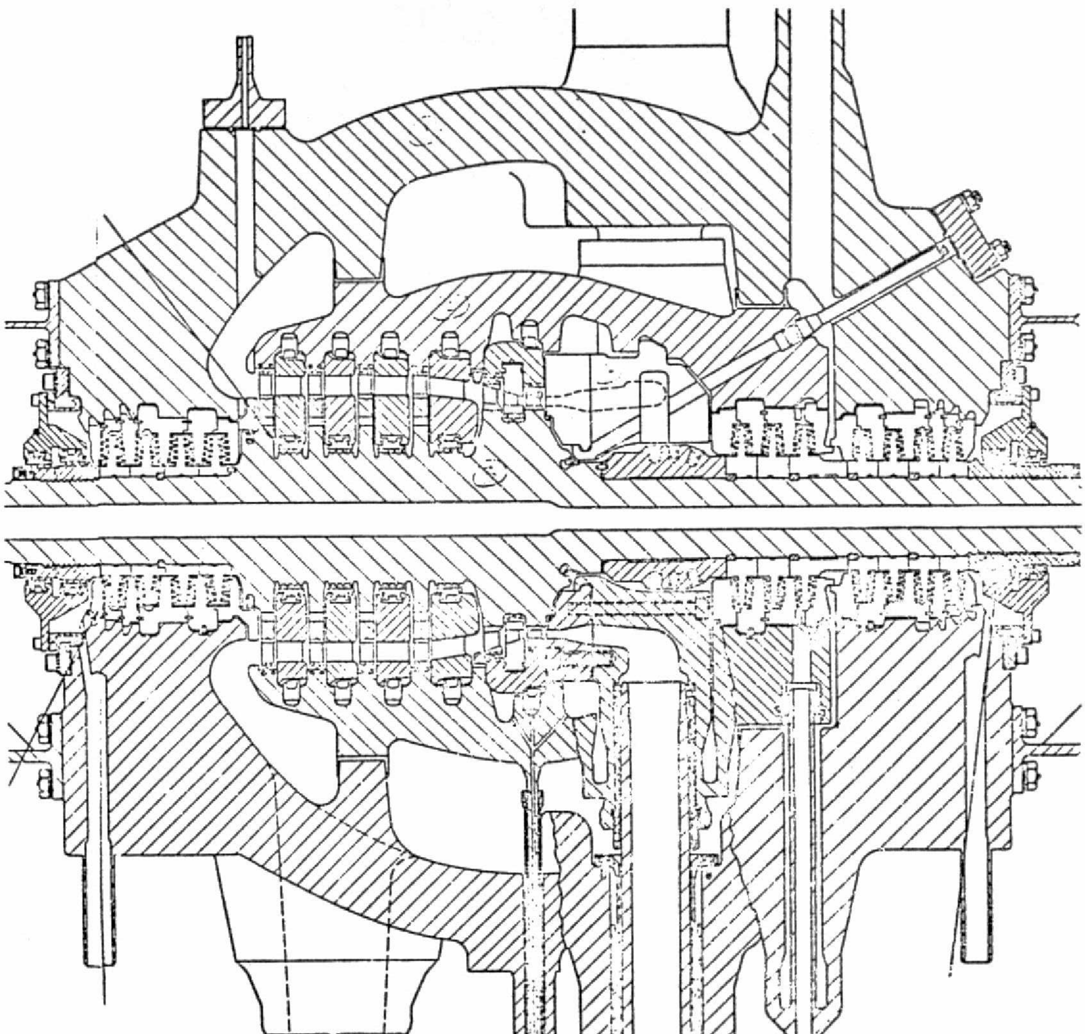
Tandem-Compound Six-Flow Reheat Turbine

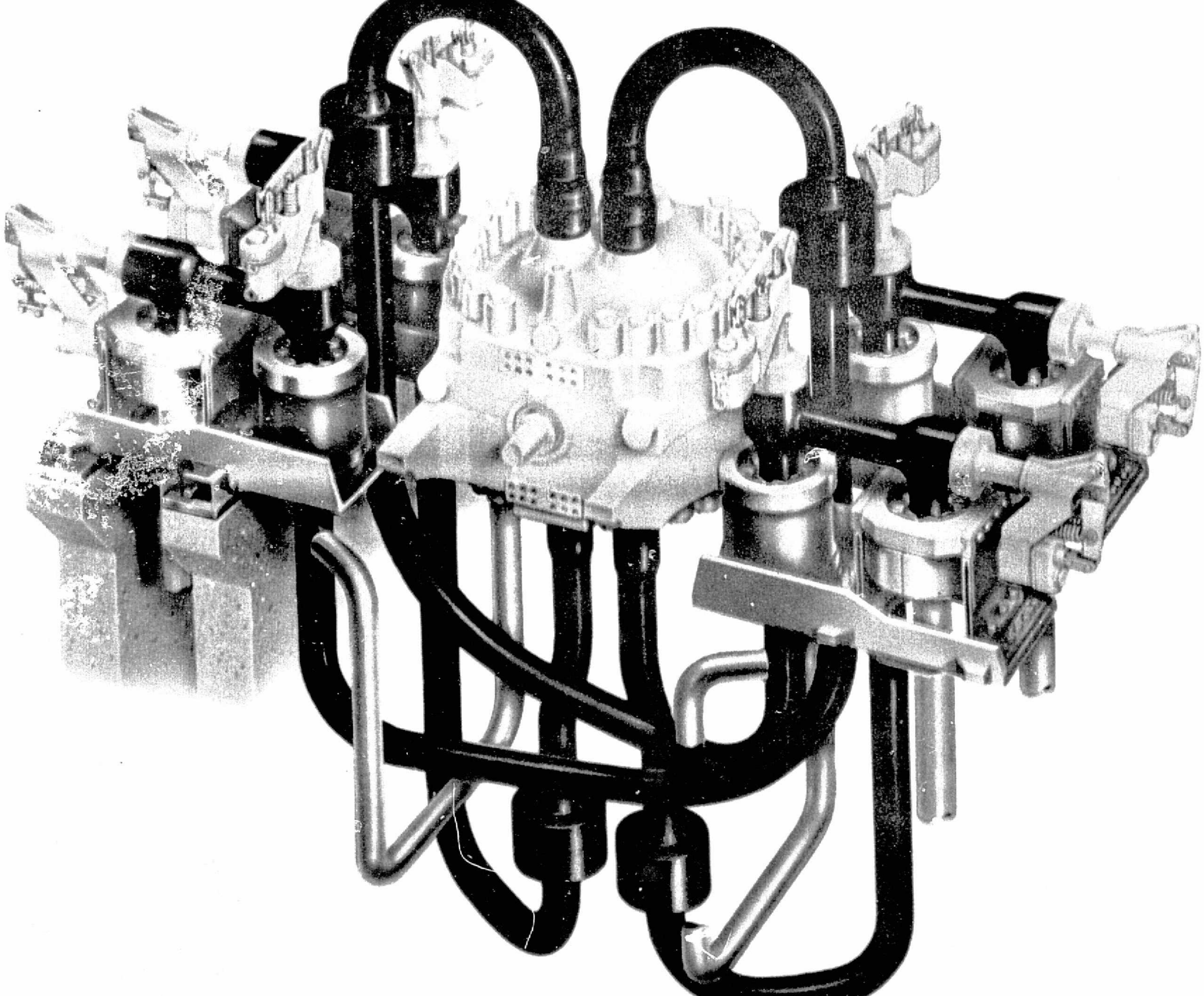


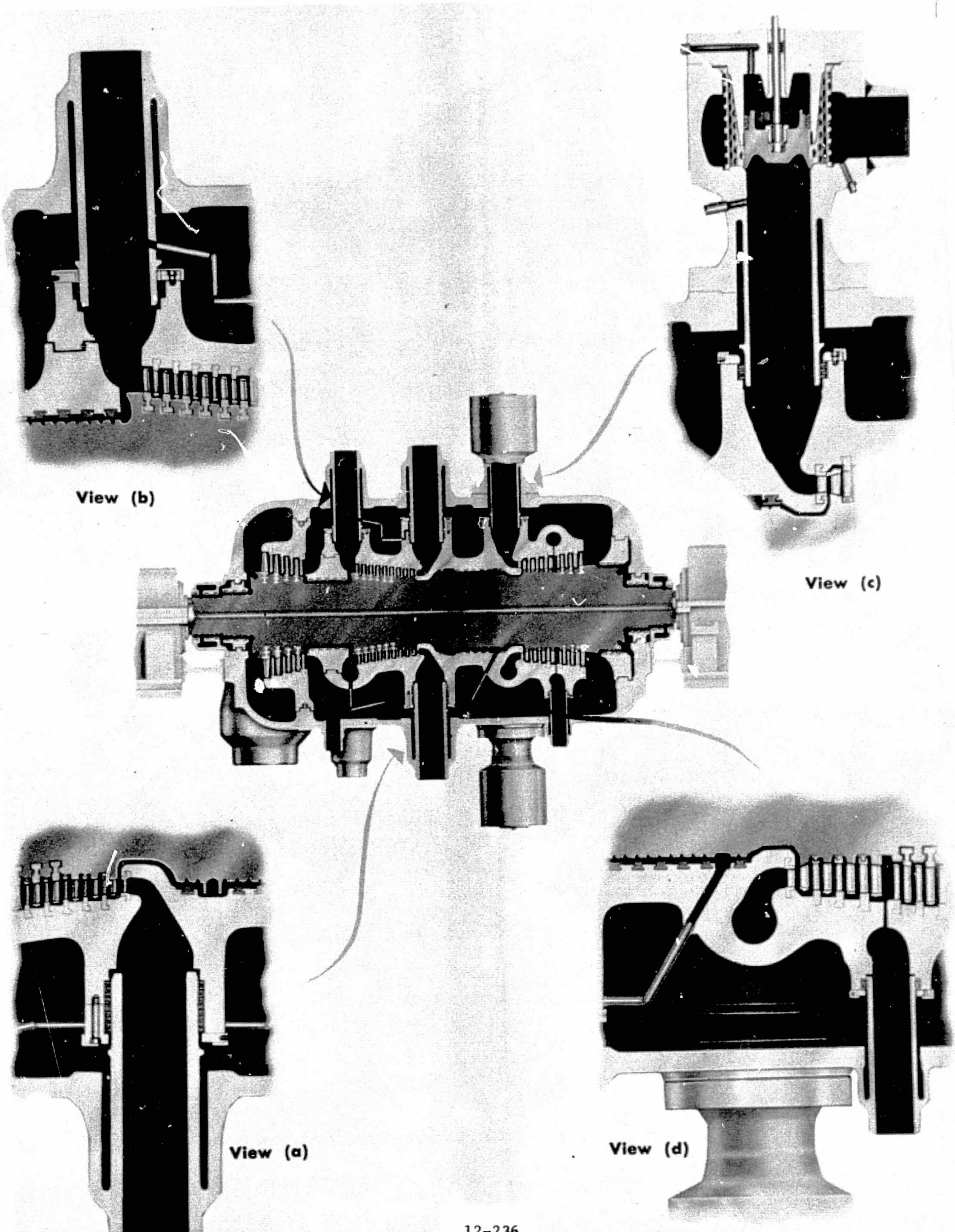
Longitudinal section of TC6F reheat turbine, 3600 rpm.

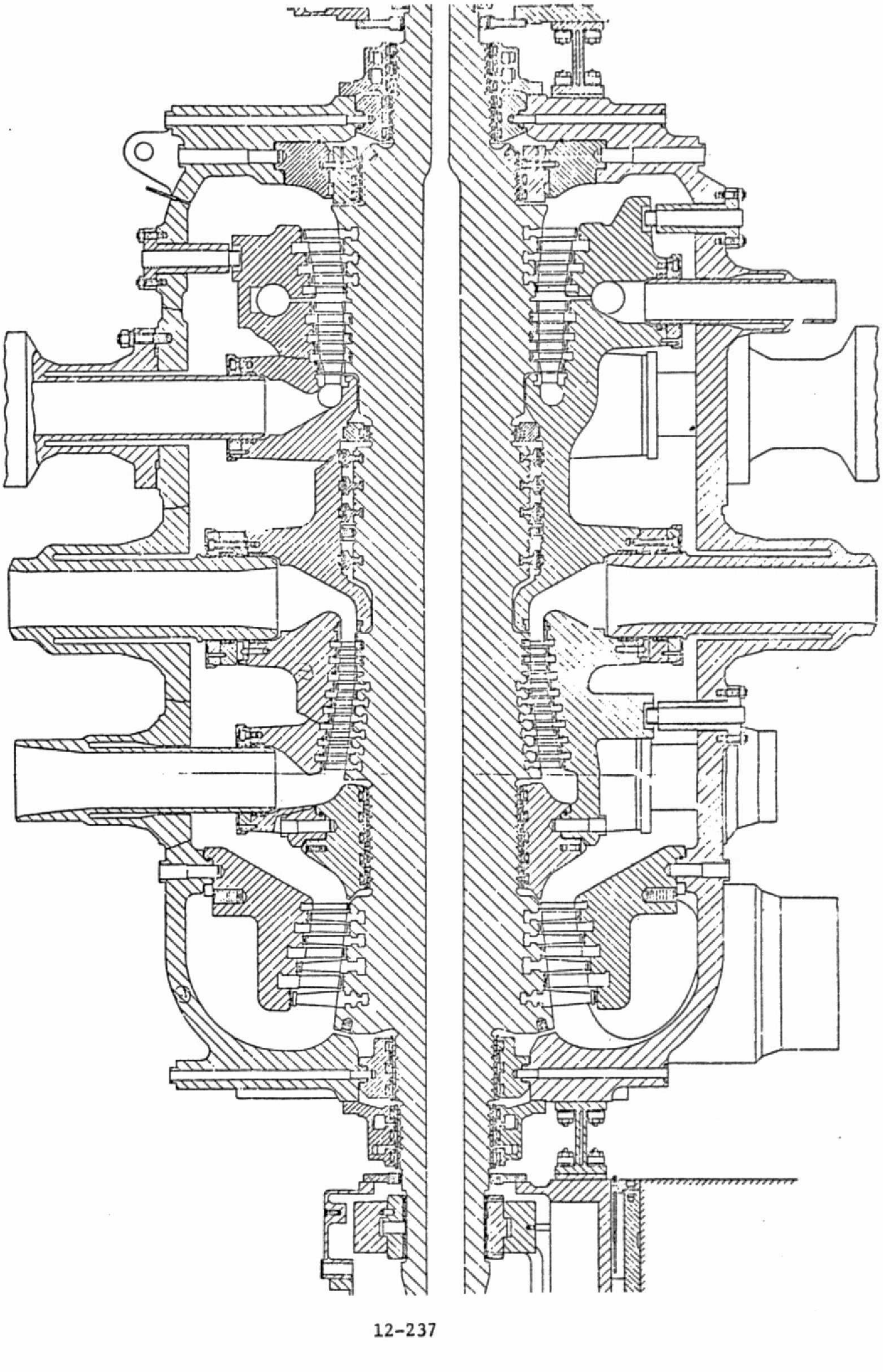
AA 12.1.2.3 Element Pictures and Features


View (b)
View (a)



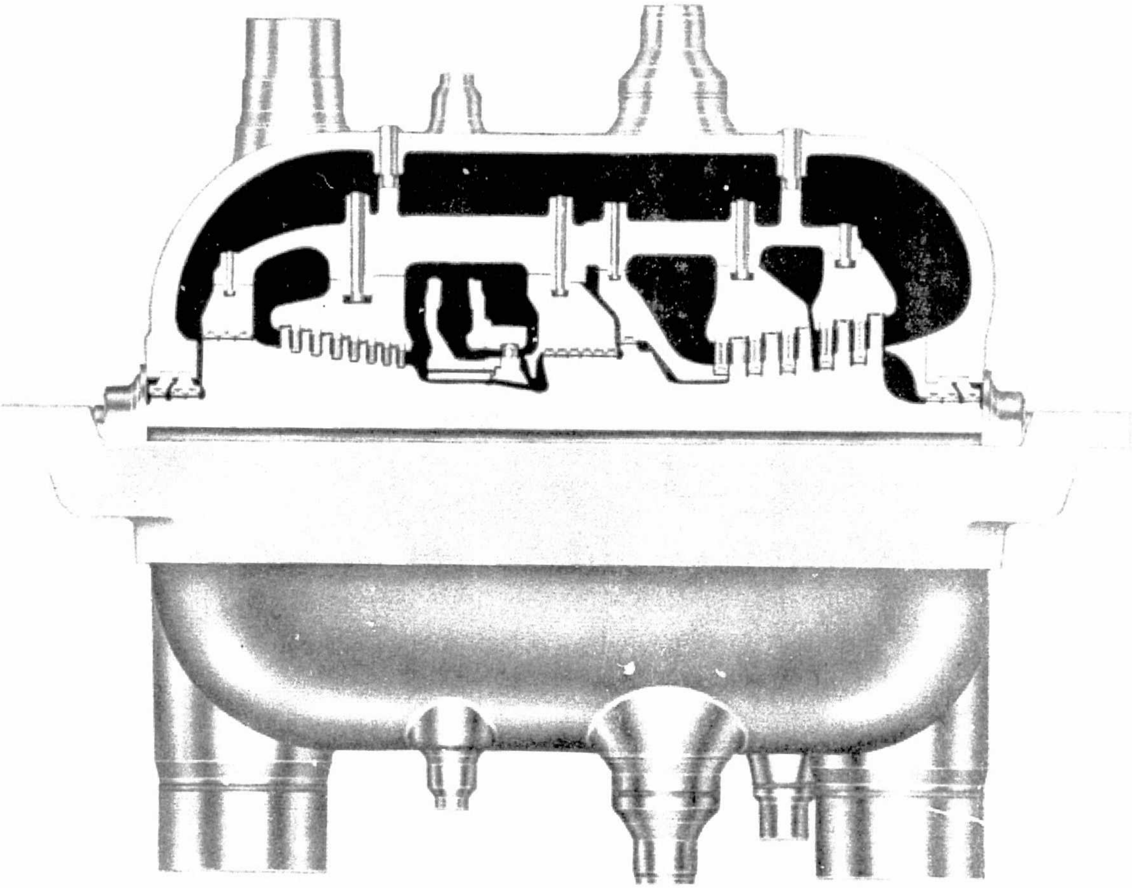



View (b)
View (c)
View (a)
View (d)



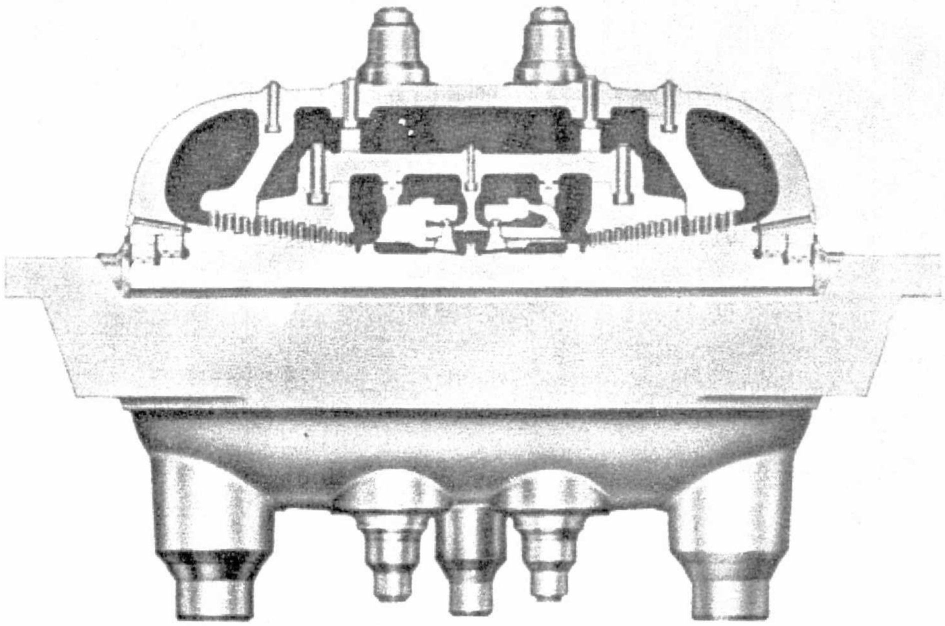
VHP-HP REHEAT TURBINE ELEMENT

3600-RPM OPPOSED-FLOW HP DESIGN



FEATURES

1. Inner and outer casing construction reduces temperature gradients, thereby minimizing thermal stresses.
2. Very high-pressure and high-pressure elements balanced independently.
3. Very high-pressure inlet and exhaust piping brought through inner casing by slip joints.



High-Pressure Element

3600-Rpm Double-Flow Design

Features

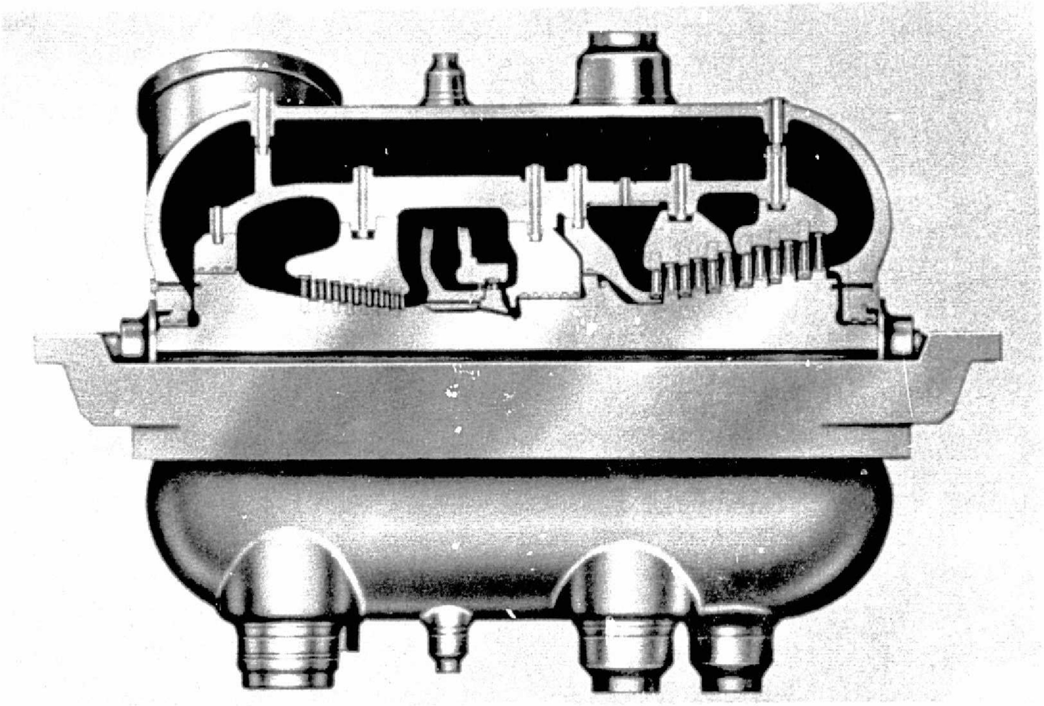
1) Inner and outer casing construction reduces thermal gradients, thereby reducing wall thickness and bolting size.

2) Steam inlet piping connected to the inner casing by slip joints in order to reduce distortion due to temperature changes.

3) Double flow design insures thrust balance.

4) Rotor checked in heater box for thermal stability prior to shipment.

5) Ultra-sonic test of rotor performed at steel mill and at the Westinghouse factory.



HP-IP Reheat Turbine Element

Features

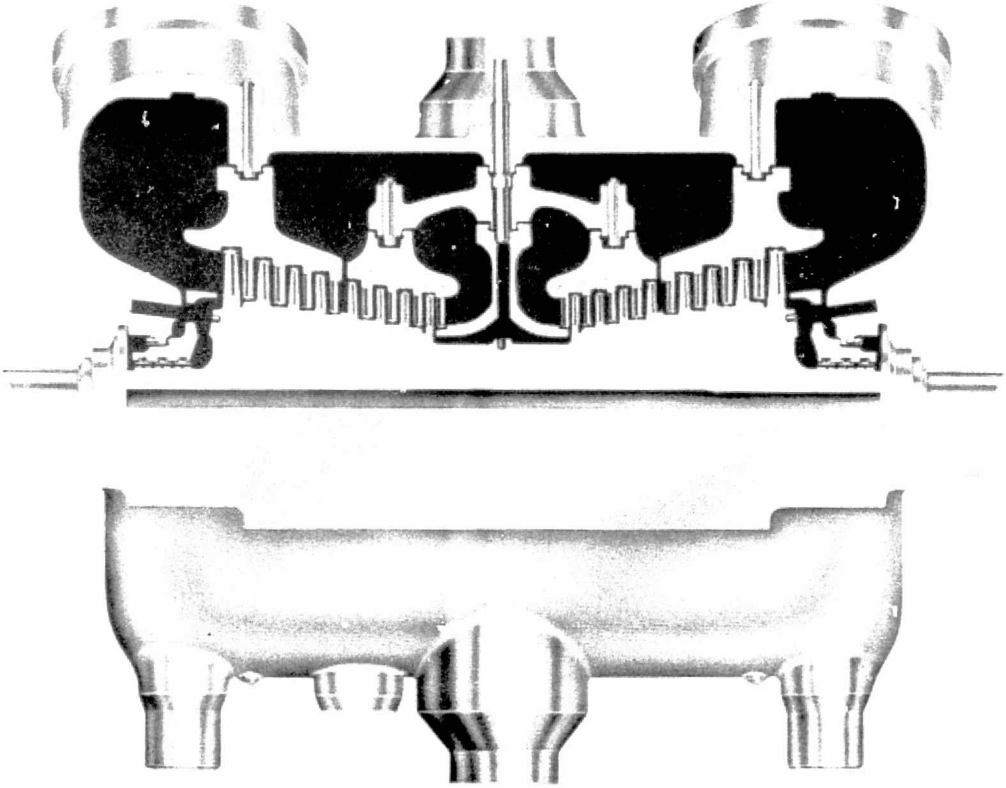
1) Inner and outer casing construction reduces temperature gradients, thereby minimizing thermal stresses.

2) High-pressure and intermediate-pressure elements balanced independently.

3) High-pressure inlet and exhaust piping brought through inner casing by slip joints.

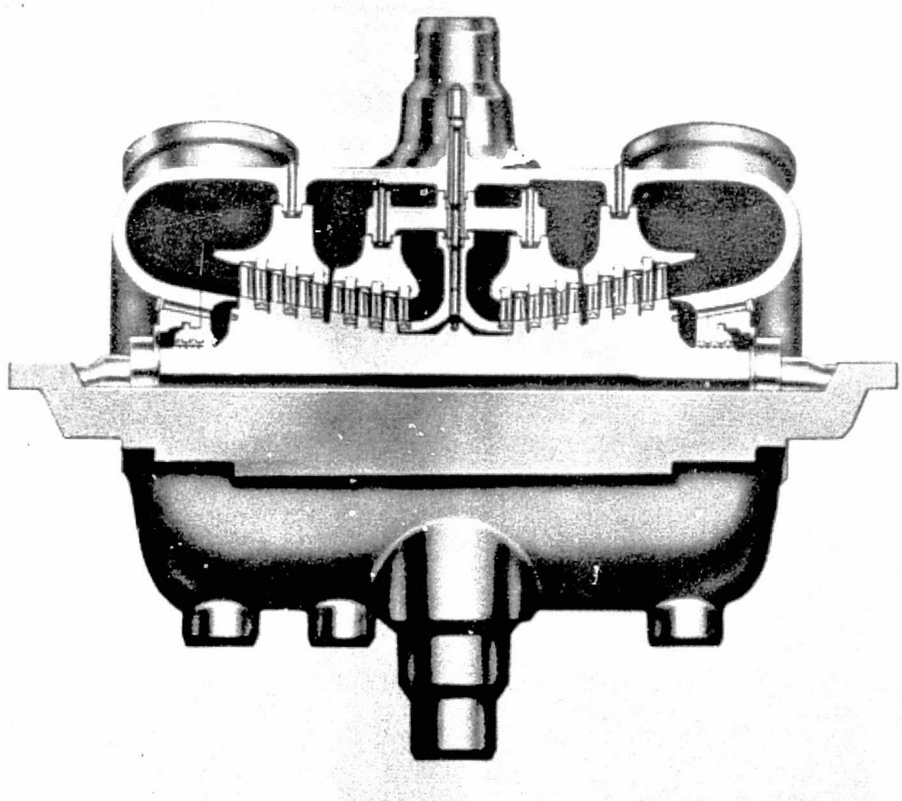
INTERMEDIATE PRESSURE ELEMENT

3600-RPM DOUBLE-FLOW DESIGN



FEATURES

1. Inner and outer casing construction reduces temperature gradients, thereby minimizing thermal stresses.
2. Steam inlet piping connected to the inner casing by slip joints in order to reduce distortion due to temperature changes.
3. Double flow design insures thrust balance.
4. Rotor checked in heater box for thermal stability prior to shipment.
5. Ultra-sonic test of rotor performed at steel mill and at the Westinghouse factory.



57

Intermediate Pressure Cylinder

3600-Rpm Double-Flow Design

Features

1) Inner and outer casing construction reduces thermal gradients, thereby reducing wall thickness and bolting size.

2) Steam inlet piping connected to the inner casing by slip joints in order to reduce distortion due to temperature changes.

3) Double flow design insures thrust balance.

4) Rotor checked in heater box for thermal stability prior to shipment.

5) Ultrasonic test of rotor performed at steel mill and at the Westinghouse factory.

Subappendix AA 12.1.3

WEIGHTS AND DIMENSIONS

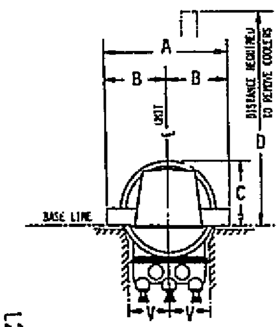
500 MW Plant

2.00" HgA

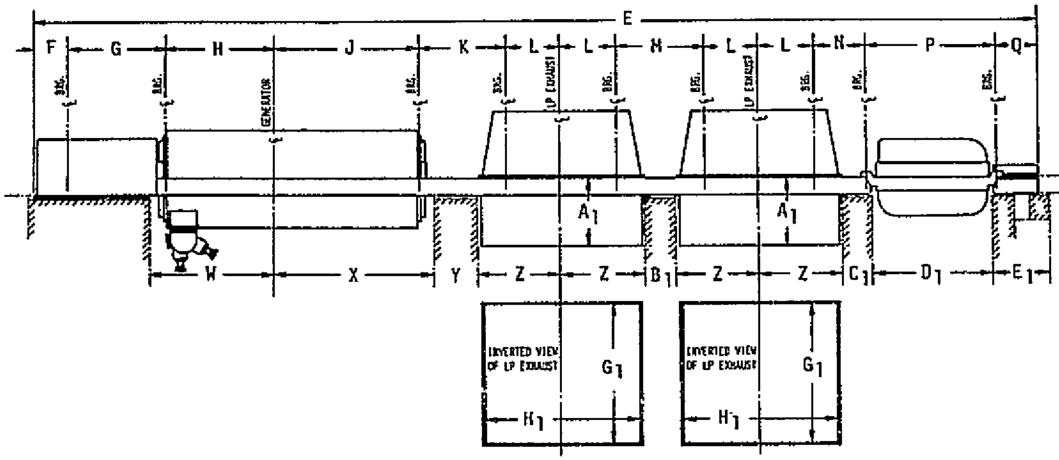
Item 9 - 3500 psig 1000°/1000°

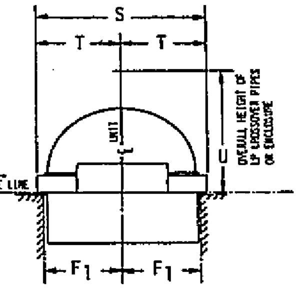
Similar to Item 16

12-245

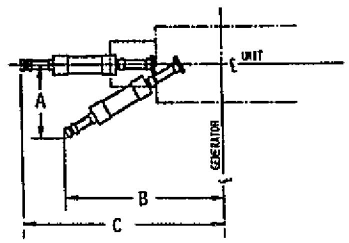


GENERATOR END VIEW





TURBINE END VIEW



DISTANCE REQUIRED TO REMOVE GENERATOR ROTOR

A	269
B	576
C	660

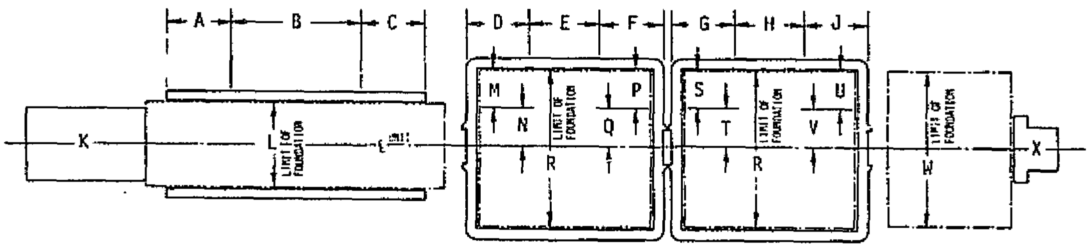
DIMENSIONS (INCHES)

A	166	J	234.5	S	258	A_1	102
B	83	K	97	T	129	B_1	39
C	125	L	91.5	U	196.25	C_1	42
D	304	M	111	V	68	D_1	211
E	1580.32	N	68	W	205	E_1	96.5
F	45.62	P	228	X	259.5	F_1	115.5
G	168.25	Q	83.44	Y	36	G_1	216
H	178.5	R	30	Z	127.5	H_1	240

(Dimensions are without turbine enclosure)

Sheet 2 of 3

12-246



FOUNDATION LOADING DIAGRAM

DIMENSIONS (INCHES)

A, B, C	409.5	J	83.5	T	72
		L	136	U	50.5
		M	50.5	V	72
D	83.5	N	72	W	270
E	102	P	50.5		
F	83.5	Q	72		
G	83.5	R	[illegible]		
H	102	S	50.5		

LOAD VALUES (POUNDS)

A, B, C	476500	J	21700	U	9600
		K	53000	V	163200
		M	9300	X	258000
D	21700	N	35500		
E	90600	P	9300		
F	21500	Q	31100		
G	21500	S	9300		
H	39600	T	31100		

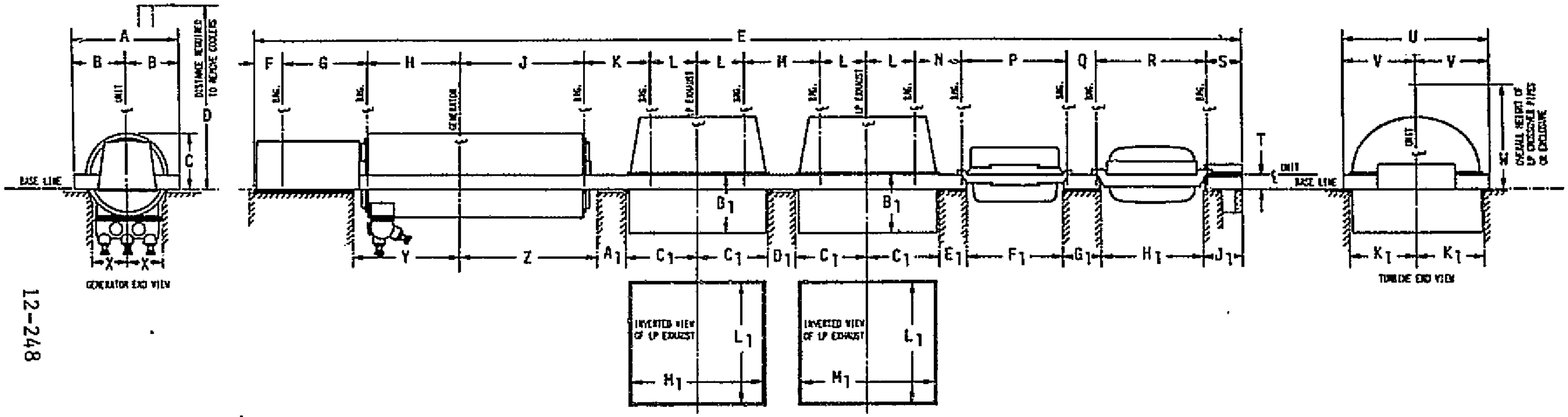
NOTE: ALL DIMENSIONED LOAD VALUES ARE SAME FOR EACH SIDE OF CENTERLINE OF UNIT

500 MW Plant

2.00" HgA

Item 12 - 3500 psig 1000°/1200°

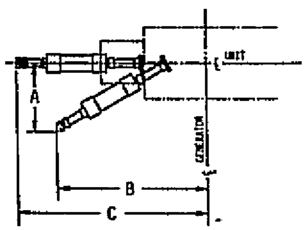
Similar to Item 19



GENERATOR END VIEW

TURBINE END VIEW

12-248



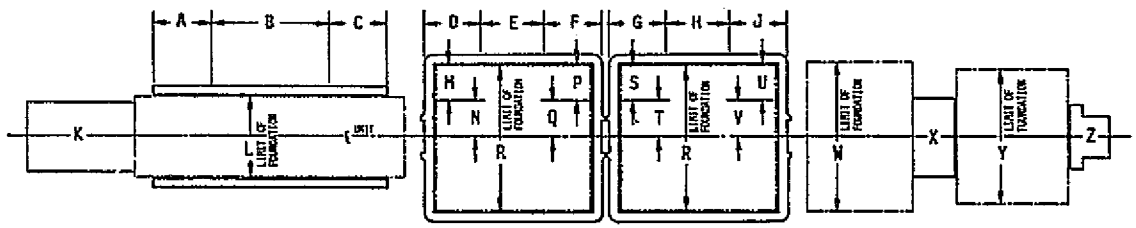
DISTANCE REQUIRED TO REMOVE GENERATOR ROTOR

A	269
B	576
C	660

DIMENSIONS (INCHES)

A	166	J	234.5	S	65.5	A_1	36	J_1	90
B	83	K	97	T	30	B_1	102	K_1	115.5
C	125	L	91.5	U	258	C_1	127.5	L_1	216
D	304	M	111	V	129	D_1	39	M_1	240
E	1808.38	N	68	W	243.25	E_1	42		
F	45.62	P	192	X	68	F_1	173.5		
G	168.25	Q	60	Y	205	G_1	77		
H	178.5	R	222	Z	259.5	H_1	206.5		

(Dimensions are without turbine enclosure)



FOUNDATION LOADING DIAGRAM

DIMENSIONS (INCHES)

A, B, C	409.5	J	83.5	T	72
		L	136	U	50.5
		M	50.5	V	72
D	83.5	N	72	W	245
E	102	P	50.5	Y	245
F	83.5	Q	72		
G	83.5	R	231		
H	102	S	50.5		

LOAD VALUES (POUNDS)

A, B, C	476500	J	21400	U	9400
		K	53000	V	115300
		M	9400	X	408900
D	21400	N	34700	Z	242700
E	94600	P	9300		
F	21500	Q	31200		
G	21500	S	9300		
H	92800	T	31200		

NOTE: ALL DIMENSIONED LOAD VALUES ARE SAME FOR EACH SIDE OF CENTERLINE OF UNIT.

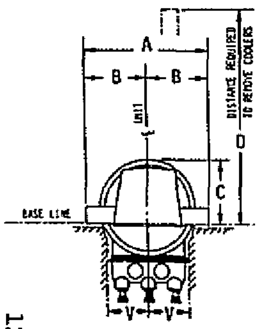
500 MW Plant

3.50" HgA

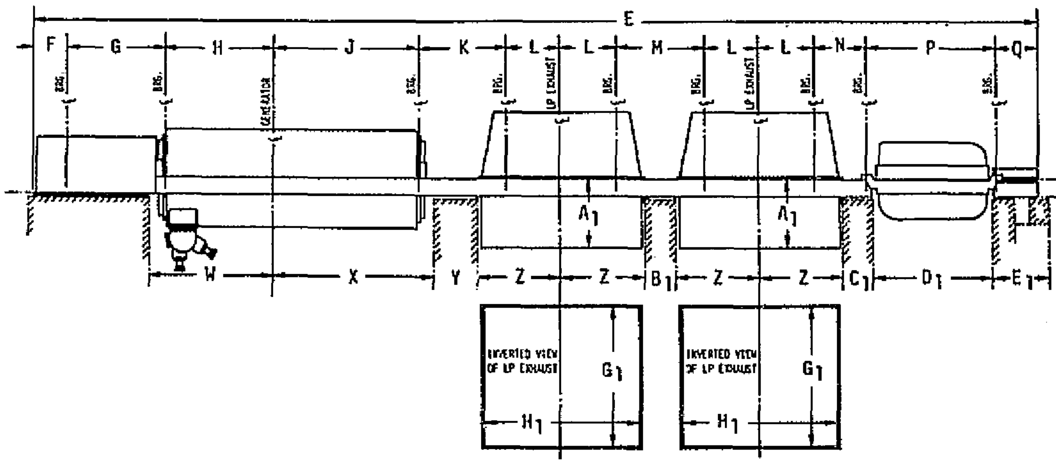
Item 9 - 3500 psig 1000°/1000°

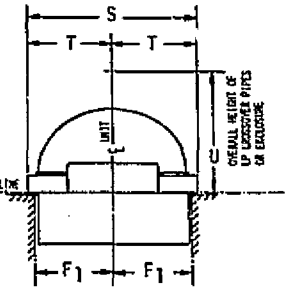
Similar to Item 16

12-251

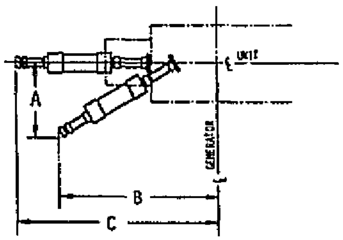


GENERATOR END VIEW





TURBINE END VIEW



DISTANCE REQUIRED TO REMOVE GENERATOR ROTOR

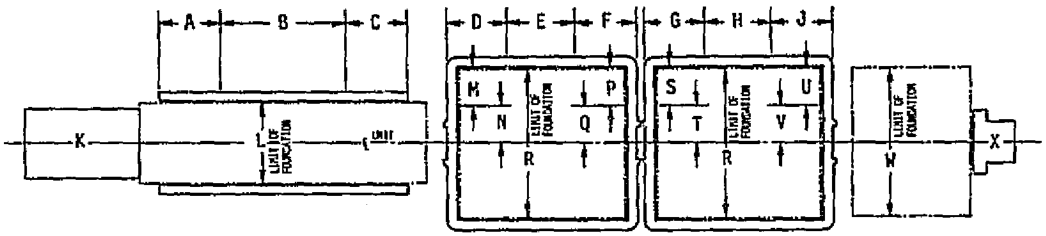
A	269
B	576
C	660

(Dimensions are without turbine enclosure)

DIMENSIONS (INCHES)

A	166	J	234.5	S	234	A_1	81
B	83	K	102	T	117	B_1	39
C	125	L	80.5	U	200	C_1	36
D	304	M	121	V	68	D_1	213
E	1552.32	N	69	W	205	E_1	99.75
F	45.62	P	228	X	259.5	F_1	103.5
G	168.25	Q	83.44	Y	36	G_1	192
H	178.5	R	30	Z	121.5	H_1	228

12-252



FOUNDATION LOADING DIAGRAM

DIMENSIONS (INCHES)

A, B, C	409.5	J	85	T	54.5
D	85	L	136	U	56
E	87	M	56	V	54.5
F	85	N	54.5	W	270
G	85	P	56		
H	87	Q	54.5		
		R	207		
		S	56		

LOAD VALUES (POUNDS)

A, B, C	476500	J	16300	U	10000
D	16300	K	53000	V	130000
E	75000	M	10000	X	255000
F	16300	N	31000		
G	16300	P	10000		
H	70700	Q	27000		
		S	10000		
		T	27000		

NOTE: ALL DIMENSIONED LOAD VALUES ARE SAFE FOR EACH SIDE OF CENTERLINE OF UNIT.

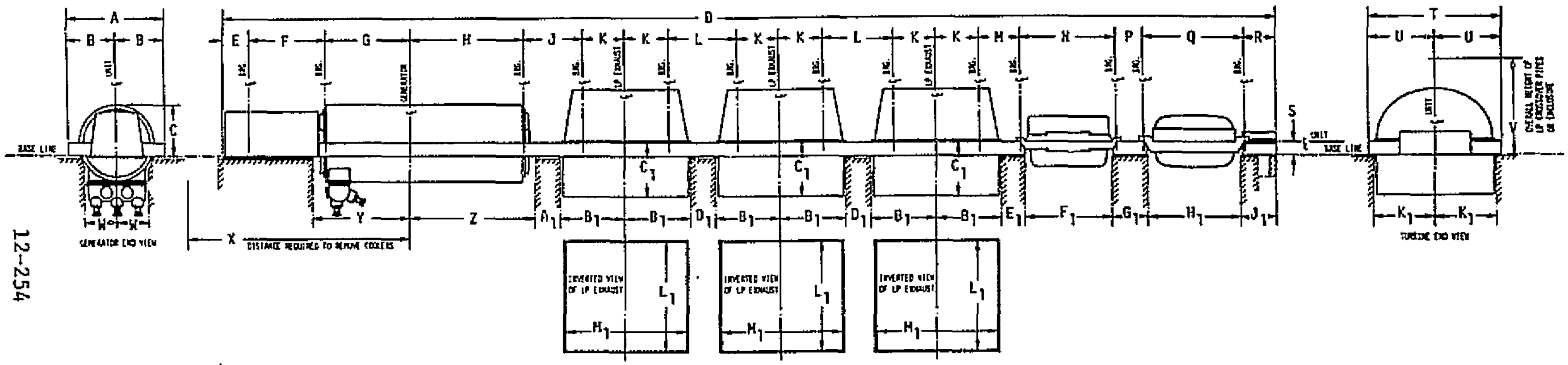
900 MW Plant

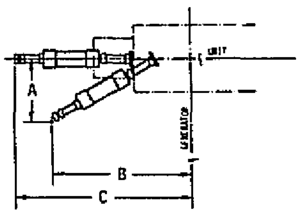
2.00" HgA

Item 9 - 3500 psig 1000°/1000°

2-115 x 275 222-57-72-72-72

12-254





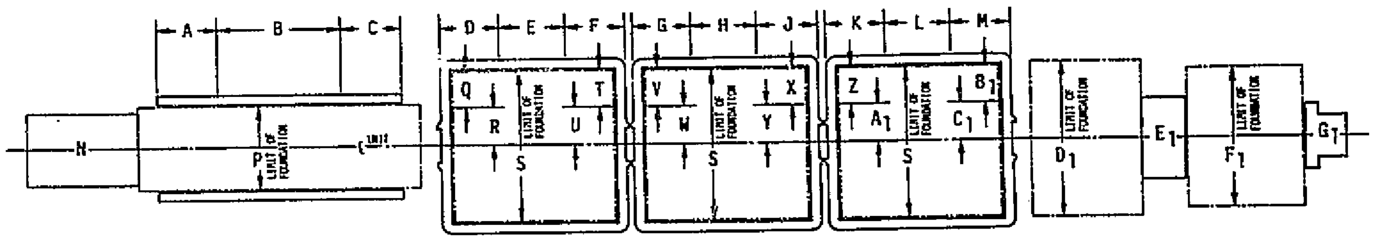
DISTANCE REQUIRED TO REMOVE GENERATOR ROTOR

A	256
B	635
C	718

DIMENSIONS (INCHES)

A	220	J	100	S	30	A_1	36	J_1	90
B	110	K	91.5	T	258	B_1	102	K_1	115.5
C	188.5	L	111	U	129	C_1	127.5	L_1	216
D	2144.69	M	68	V	253	D_1	39	M_1	240
E	41.69	N	216	W	68	E_1	42		
F	160.5	P	60	X	632	F_1	197.5		
G	202	Q	222	Y	235.5	G_1	77		
H	238	R	65.5	Z	266	H_1	206.5		

(Dimensions are without turbine enclosure)



FOUNDATION LOADING DIAGRAM

DIMENSIONS (INCHES)

A, B, C	430	J	83.5	T	50.5	B_1	50.5
		K	83.5	U	72	C_1	72
		L	102	V	50.5	D_1	245
D	83.5	M	83.5	W	72	F_1	245
E	102	P	136	X	50.5		
F	83.5	Q	50.5	Y	72		
G	83.5	R	72	Z	50.5		
H	102	S	231	A_1	72		

LOAD VALUES (POUNDS)

A, B, C	650500	J	16700	T	8750	A_1	37400
		K	16700	U	37400	B_1	8400
		L	99800	V	8750	C_1	136000
D	16700	M	16700	W	37400	E_1	437500
E	100400	N	62500	X	8750	G_1	242700
F	16700	Q	8450	Y	37400		
G	16700	R	42400	Z	8750		
H	107700	S					

NOTE: ALL DIMENSIONED LOAD VALUES ARE SAFE FOR EACH SIDE OF CENTERLINE OF UNIT.

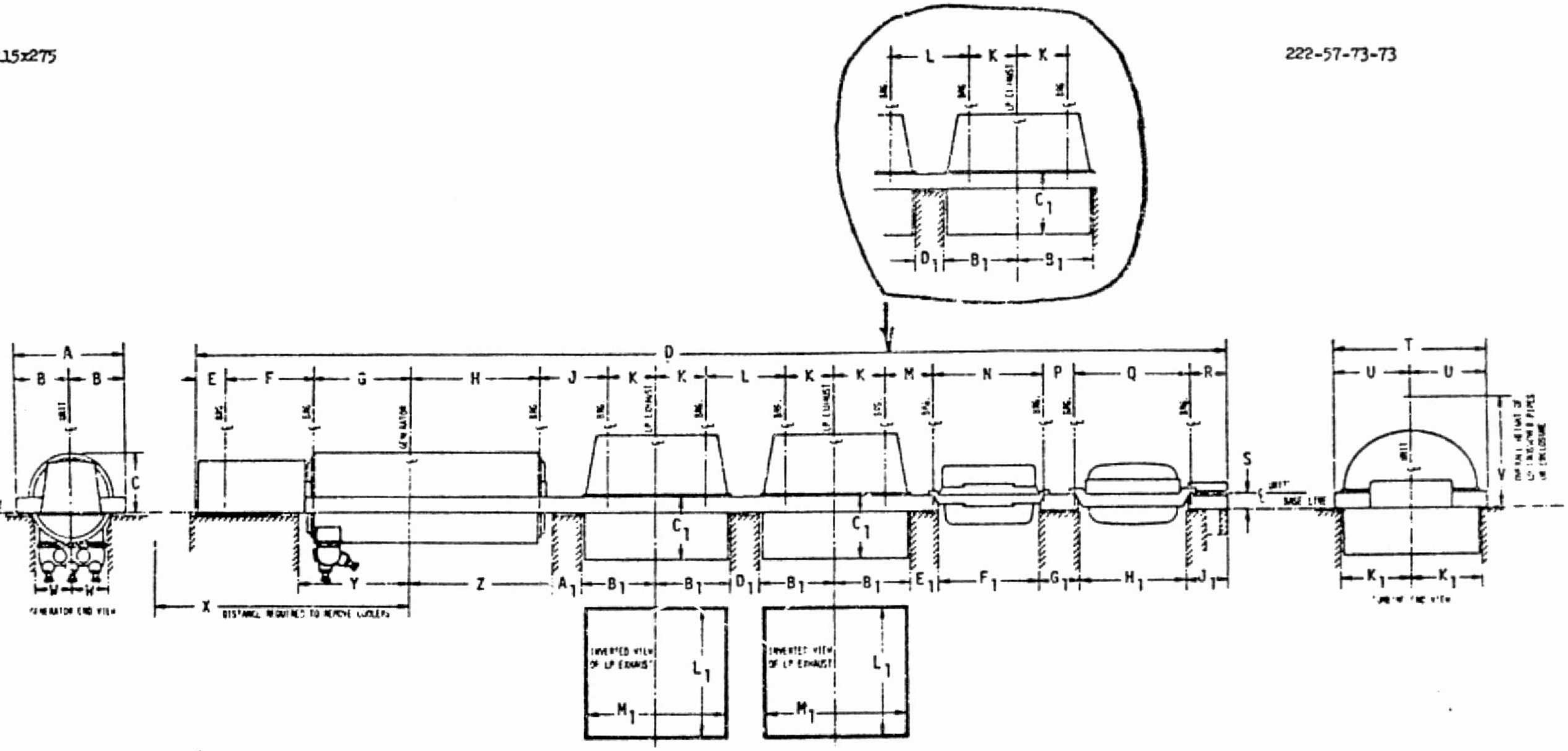
900 MW Plant

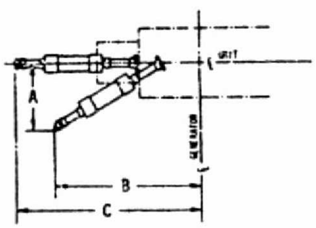
3.50" HgA

Item 9 - 3500 psig 1000°/1000°

2-115x275

222-57-73-73





DISTANCE REQUIRED TO REMOVE GENERATOR ROTOR

A	256
B	635
C	718

(Dimensions are without turbine enclosure)

DIMENSIONS (INCHES)

A	220	J	122.5	S	30	A_1	45	J_1	90
B	110	K	96	T	294	B_1	145.5	K_1	133.5
C	188.5	L	156	U	147	C_1	118	L_1	252
D	2311.69	M	95.5	V	264.25	D_1	57	M_1	276
E	41.69	N	216	W	68	E_1	57		
F	160.5	P	60	X	632	F_1	196.5		
G	202	Q	222	Y	235.5	G_1	77		
H	238	R	65.5	Z	[illegible]	H_1	[illegible]		

SHEET 2 OF 3

12-257

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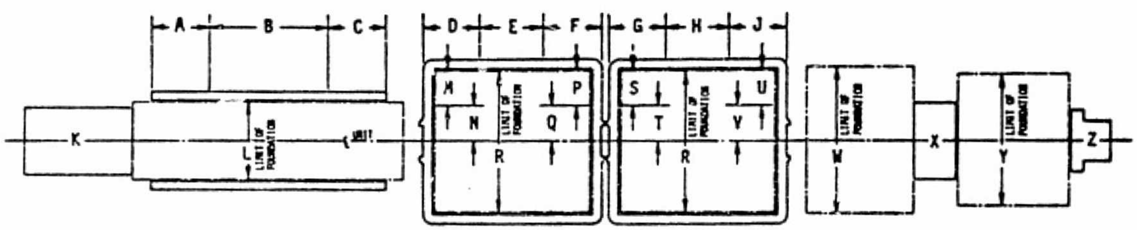
OF POOR QUALITY



FOUNDATION LOADING DIAGRAM

DIMENSIONS (INCHES)

A, B, C	430	J	92.5	T	90
		L	136	U	50.5
		M	50.5	V	90
D	92.5	N	90	W	245
E	120	P	50.5	Y	256
F	92.5	Q	90		
G	92.5	R	267		
H	120	S	50.5		

LOAD VALUES (POUNDS)

A, B, C	650500	J	33400	U	14400
		K	62500	V	146800
		M	13700	X	437500
D	33400	N	57000	Z	242800
E	161700	P	14400		
F	33400	Q	49000		
G	33400	S	14400		
H	161700	T	49000		

NOTE: ALL DIMENSIONED LOAD VALUES ARE SAFE FOR EACH SIDE OF CENTERLINE OF UNIT.

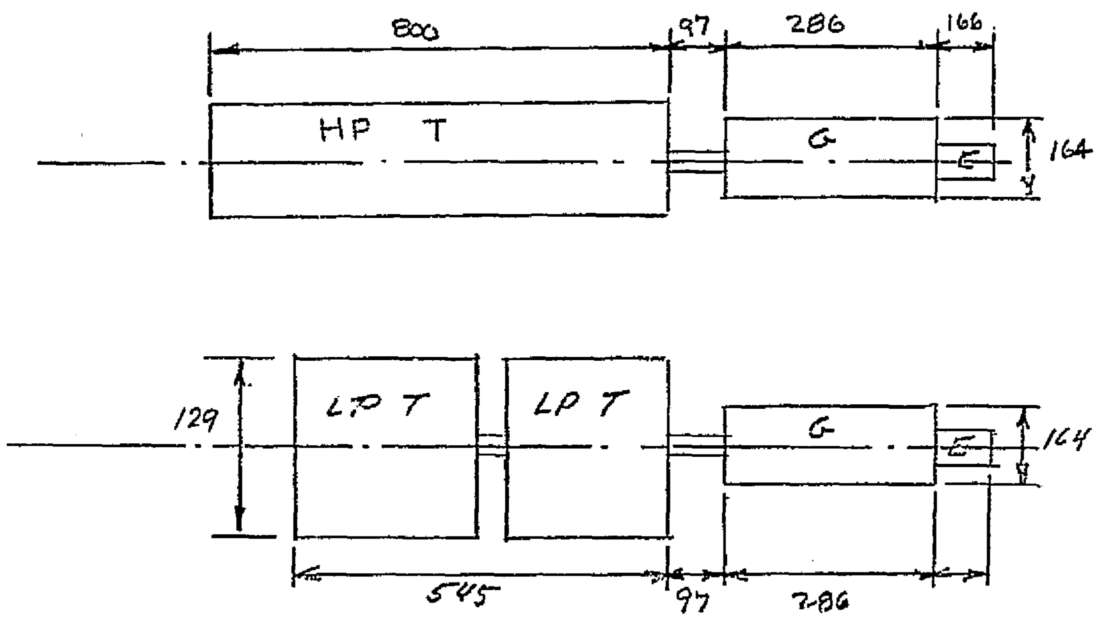
500 MW Plant

2.00" HgA

Item 4 - 5000 psig 1400°/1400°/1400°

Similar to Items 8, 5, 3 & 5-I

All Cross-Compound Units



All Dimensions in Inches

Plan View

Appendix A 12.2

DESCRIPTION OF PRESSURIZED BOILERS

A 12.2.1 The Duty of the Pressurized Boilers for the Base Case, Point 16

Due to the desired close coupling arrangement of the gas turbine-compressor units, the total heating duty is divided among four boilers. Each boiler transfers 258.1 MWt to the steam cycle. Each of the four boilers burns 45.133 kg/s (3.582 x 10^5 lb/hr) of low-Btu gas, which is supplied from a coal gasification unit at 1144°K (1600°F) and 1.0342 MPa (150 psi) abs with 134.95 kg/s (1.071 x 10^6 lb/hr) of air supplied from a compressor at 624°K (664°F) and 1.0342 MPa (150 psi) abs. After releasing heat to the steam system the products of combustion are exhausted to the boiler gas turbine at 755°K (900°F) and 1.010 MPa (146.5 psi) abs. In order to avoid too high a boiler combustion chamber temperature, the boiler exhaust temperature is limited to 755°K (900°F) for a specified fuel/air ratio. The gas in the gas turbine, however, must be expanded from a much higher temperature than 755°K (900°F). More low-Btu gas, therefore, is burned in the gas turbine combustor.

Feedwater enters the boiler at 644°K (700°F) and 26.2 MPa (3800 psi) abs. It is raised to steam at 811°K (1000°F) and 24.235 MPa (3513 psi) abs. Following two high-pressure stage feed-heating extractions, 92.8% of the steam flow is returned to the boiler at 572°K (570°F) and 4.482 MPa (650 psi) abs for reheating to 811°K (1000°F) at 4.137 MPa (600 psi) abs. Within these constraints the primary steam flow delivered per boiler is 124.58 kg/s (0.9887 x 10^6 lb/hr), and the reheat steam flow for each of the four boilers is 115.64 kg/s (0.9178 x 10^6 lb/hr).

A 12.2.2 General Configuration of the Boiler

Since combustion and subsequent heat transfer is at elevated pressure, 1.013 MPa (10 atm) for the base case, the heat transfer surface is contained within a cylindrical pressure vessel.

In order to limit the temperature to which the vessel shell is subjected, it was decided that the wall should be internally insulated. Furthermore, in order to minimize the thickness of insulation required it was decided that the insulation be blanketed by the incoming air from the compressor which, at 624°K (664°F), is the coolest gas inside the boiler.

Since this air is available from the turbocompressor at a low elevation it is advantageous if it is directed upwards in an annular passage adjacent to the shell insulation and surrounding the heat transfer surfaces. The low-Btu fuel gas is available most conveniently at a high elevation. This is due to the configuration of the gasifier and the desire to minimize the length of high-temperature gas piping. It is, therefore, natural to merge the air stream and the gas stream at the top of the vessel and pass the combustion products downward over the heat transfer surface. This arrangement is further beneficial in that the combustion products are brought to their lowest temperature at a low elevation, where it is most convenient to exhaust to the gas turbine. Figure A 12.2.1 illustrates this layout.

A 12.2.3 Distribution of Main Evaporator, Superheat, and Reheat Tube Banks within the Pressurized Boiler

Homogeneous nonluminous flame temperatures close to 1948°K (3046°F) are anticipated in the region just below the burners. In order to maintain tube wall temperatures below 1089°K (1500°F) excellent heat transfer within the tubes is necessary, preferably to a fluid of a temperature somewhat less than the maximum steam cycle fluid temperature of 811°K (1000°F).

Dwg. 6365A35

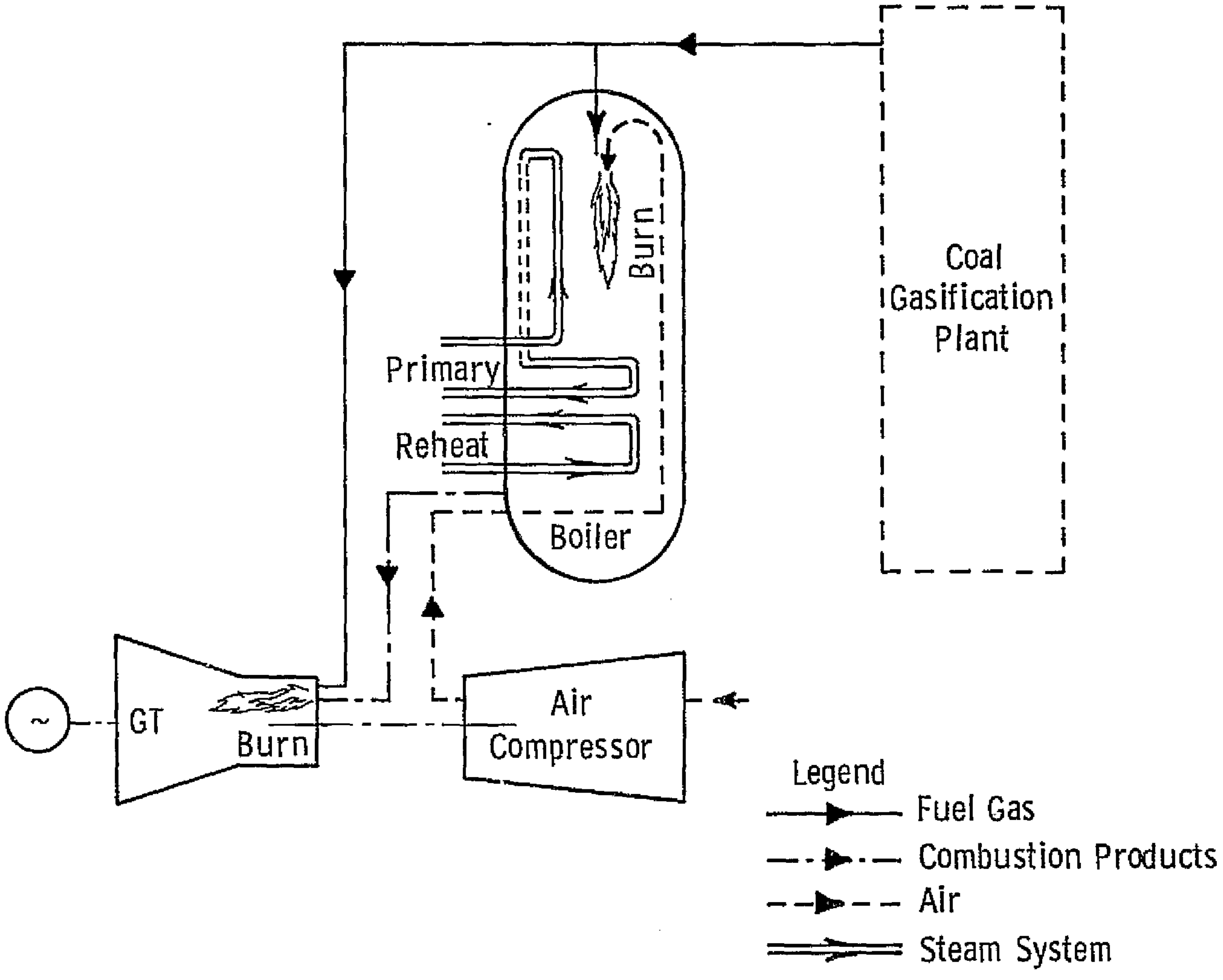


Fig. A 12.2.1—Pressurized boiler subsystem

These requirements preclude the use of the reheater section to cool the flame. The primary steam circuit, therefore, occupies the hottest region of the boiler. In line with the most advanced current practice the combustion products are cooled to 1478°K (2200°F) before being passed in crossflow over the tubes. Reduction of the gas temperature to 1478°K (2200°F) provides a little over half of the heat required to raise primary steam. Clearly, then, the primary steam circuit must be divided into two sections. The first section cools the hottest region of the flame from 1948 to 1478°K (3046 to 2200°F) and is axially parallel but countercurrent to the combustion gas stream. This is sufficient to take the feedwater from its input value of 644°K (700°F) and raise it to 678°K (760°F). This is thus a water-wall section, the details of which will be discussed later. The second section cools the gas from 1478 to 1095°K (2200 to 1512°F) and in so doing takes the water from 678°K (760°F) and raises it to its final condition as steam at 811°K (1000°F) and 24.235 MPa (3515 psi) abs. This section has a conventional tube bank configuration over which the combustion product gas passes in crossflow.

In the first primary evaporator section (the water wall) it might at first seem logical to inject the feedwater at the top where the highest flame temperatures are experienced, but for hydrodynamic reasons it is preferable to have the water flow upwards against gravity until the temperature is elevated above the pseudocritical value. The rationale for this procedure is outlined in detail in Appendix A 9.3, Section A 9.3.2. This involves collecting the partially heated water by a system of headers at the top of the water-wall section and transporting it down in headers to the crossflow section for finish superheating. The partially heated water is injected at the top of the superheating section so that the tubes, which are exposed to gas at 1366°K (2000°F) on the outside, see the coolest water at this point. The water passes in net downward flow, cocurrent with the gas, by virtue of a series of cross passes, each at a lower elevation than the previous one.

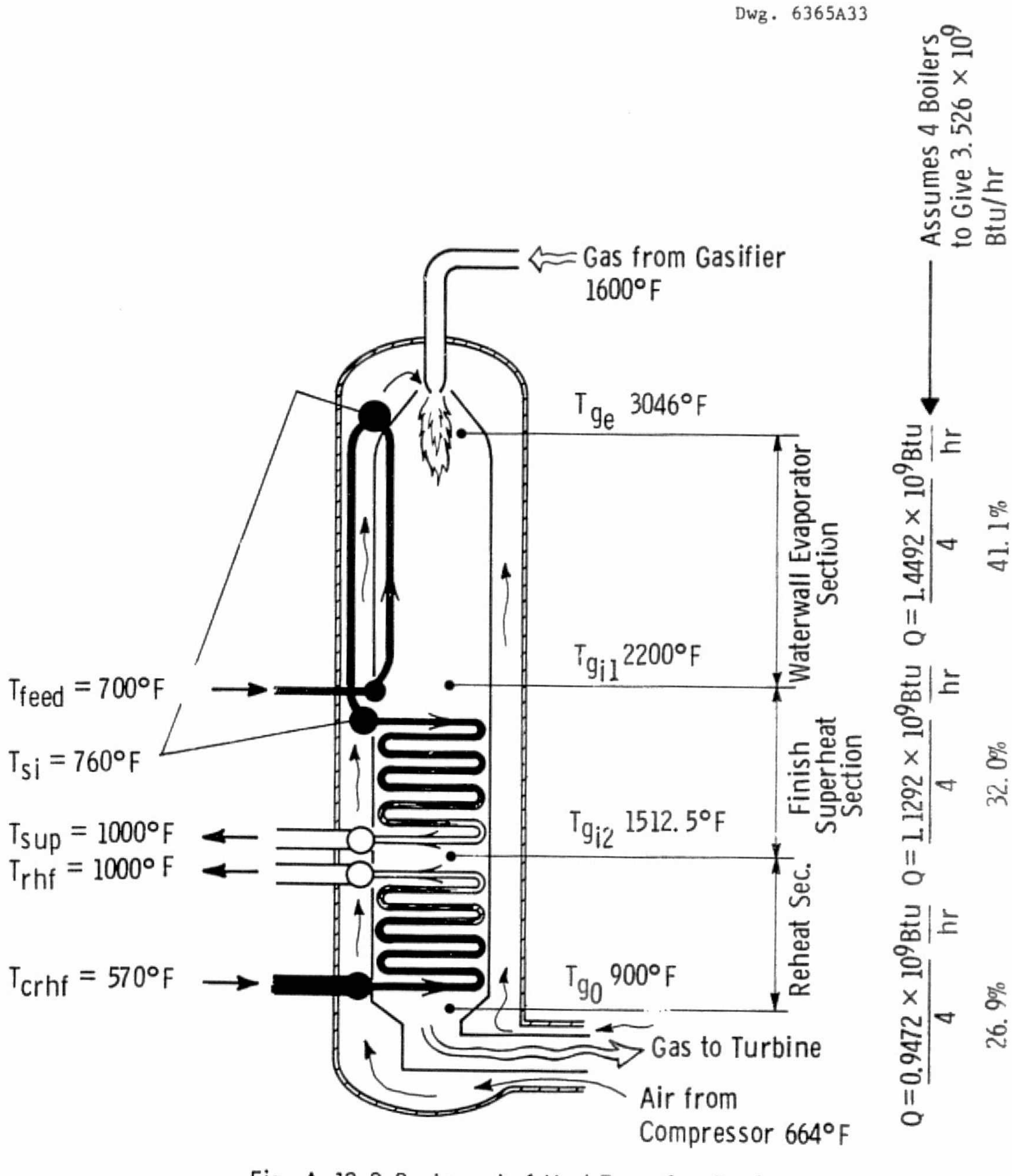


Fig. A 12.2.2—Layout of Heat Transfer Surface

The water leaves this tube bank as superheated steam at 811°K (1000°F). The combustion product gas, at 1095°K (1512°F) proceeds downward to the reheat section.

The reheat section is a conventional crossflow tube bank. In order to preserve a positive temperature difference between the gas and the stream, the cold reheat steam, at 572°K (570°F), enters at the bottom of the tube bank where the gas is at its lowest temperature value of 755°K (900°F). The steam passes in net upward flow, countercurrent to the gas, by virtue of a number of cross passes, each higher than the previous one. The steam leaves the reheater bank at the top at 811°K (1000°F)/4.137 MPa (600 psi) abs. The corresponding gas temperature is 1095°K (1512°F).

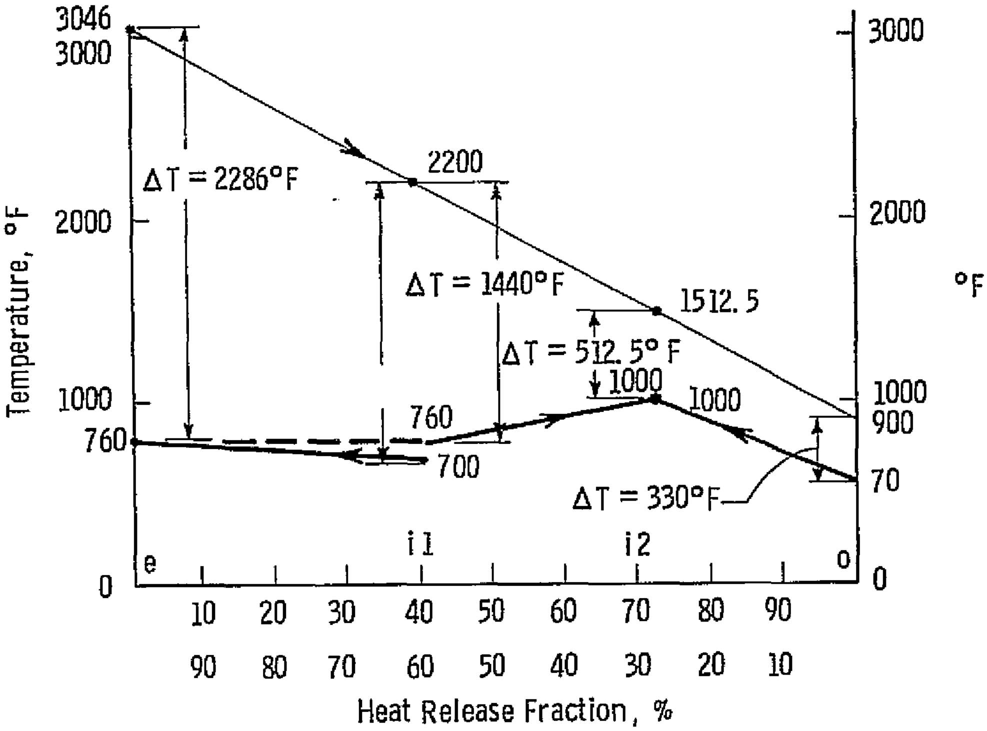
This distribution of surfaces and temperature is schematically illustrated in Figure A 12.2.2. Figure A 12.2.3 is the corresponding temperature approach diagram.

A 12.2.4 Special Features of the First Evaporator Water-Wall Section

In this section the tubes run vertically, parallel to the gas stream. At their upper extremity they are adjacent to the hottest region of the flame. The homogeneous flame temperature at this point is calculated to be 1948°K (3046°F). The flame is, however, not homogeneous in temperature; rather, there will exist within the flame, temperatures several hundred degrees higher than this value. This is one of the reasons why it is conventional practice in water-wall design to restrict the water tubes to a peripheral area surrounding the flame. The tubes are thus radiation coupled to the highest temperature zone of the flame but are impinged by gases which are actually lower in temperature than the homogeneous temperature.

In normal practice several burners are combined to produce a very large flame ball 6.096 m (20 ft) or so in diameter. This is normally enclosed with a large box or cylinder furnace wall which is made up of the water tubes. This layout has the disadvantage that very

Dwg. 6365A37



Section	ΔT_{max}, °F	ΔT_{min}, °F	$\Delta T_{max} - \Delta T_{min}$, °F	$\frac{\Delta T_{max}}{\Delta T_{min}}$	$\ln\left(\frac{\Delta T_{max}}{\Delta T_{min}}\right)$	$\frac{\Delta T_{max} - \Delta T_{min}}{\ln\left(\frac{\Delta T_{max}}{\Delta T_{min}}\right)}$
Evaporator e→i1	2286	1500	786	1.524	0.421	1867
Finish Superheat i1→i2	1440	512.5	927.5	2.81	1.033	898
Reheater i2→0	512	330	182	1.55	0.439	414.6

Fig. A 12.2.3—Temperature approach diagram and table little tube surface per unit volume can be provided. Thus, with a normal heat transfer coefficient, a considerable length of furnace is required before the combusting flame as such no longer exists and the combustion products are cooled to a temperature where they can be passed over crossflow tube banks. This length is typically of the order of 30.48 m (100 ft).

In this boiler design we sought to increase the surface area of the water wall per unit volume of the furnace by locating each of the seven burners employed on the center axis of a hexagonal water-wall passage 1.58 m (5.2 ft) across flats. The seven hexagonal passages are then clustered to form a honeycomb. See Figure A 12.2.4.

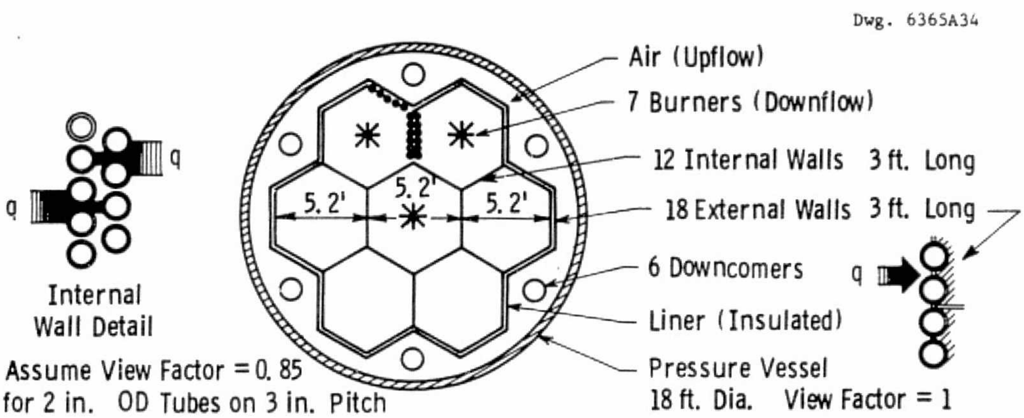


Fig. A 12.2.4 – Proposed layout of vaporator section (water walls)

The 18 external facets of the homecomb contain one row of tubes. The gaps between tubes on the external facets are occupied by T bars welded to the tubes. This provided a closed outer periphery also, and the T bars pick up heat from the gas and conduct it to the tubes.

The 12 internal facets of the honeycomb contain two rows of tubes. The gaps betwen tubes are left open. This provides a higher radiation view factor than would be the case if the gaps were filled by a ceramic. Also, the gaps provide hydrodynamic coupling between the seven passages, benefiting the stability of flow in the passages.

It is estimated that this arrangement provides nearly three times as much effective surface as would a conventional water-wall design of the same height and cross sections.

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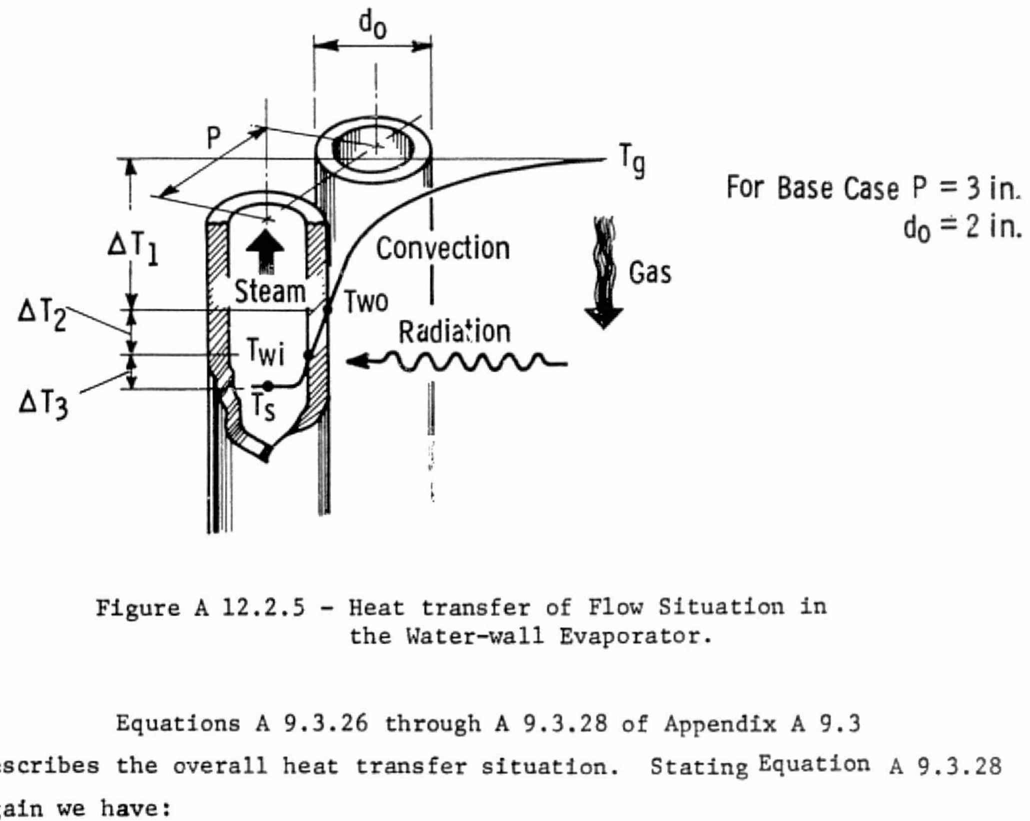

Figure A 12.2.5 - Heat transfer of Flow Situation in the Water-wall Evaporator.

Equations A 9.3.26 through A 9.3.28 of Appendix A 9.3 describes the overall heat transfer situation. Stating Equation A 9.3.28 again we have:

$$h_o = \frac{1}{1/h_g + 1/h_w + 1/h_s} \tag{A 12.2.1}$$

The heat transfer coefficient from the gas to the wall, h_g, has two components; namely, that due to radiation from a nonluminescent gas and that due to forced convection. The basic equations for these situations will be rewritten here, but for a detailed description of the procedures involved the reader is referred to Section A 9.3.4.

$$h_g = h_{rad} + h_{conv} \qquad \text{(A 12.2.2)}$$

where

$$h_{rad} = \frac{\sigma \left\{ \varepsilon_g \ (\bar{T}_g + 460)^4 - \alpha_{g.w} \ (T_{w_o} + 460)^4 \right\}}{\bar{T}_g - T_{w_o}} \qquad \text{(A 12.2.3)}$$

and

$$h_{conv} = \frac{0.023 \ k_g}{d_o} \left(\frac{V \ \rho_g \ d_o}{\mu_g} \right)^{0.8} Pr^{0.4} \qquad \text{(A 12.2.4)}$$

In Equation A 12.2.3 ε_g in the pressurized gas emissivity at $\bar{T}_g$ and is the sum of contributions from the radiating components of the gas; namely, water vapor and carbon dioxide. The partial pressures of these components, on a percentage of total pressure basis, for the base case are:

$$P_{CO_2} = 10.61\% \qquad \text{(A 12.2.5)}$$

$$P_{H_2O} = 4.42\% \qquad \text{(A 12.2.6)}$$

The radiant path length for a hexagonal enclosure is given by the equation:

$$L = 0.9 \text{ (Dimension across Flats)} \qquad \text{(A 12.2.7)}$$

Using a 1.58 m (5.2 ft) across flats dimension:

$$L = 1.426 \text{ m } (4.68 \text{ ft}) \tag{A 12.2.8}$$

With these basic parameters in hand and proceeding by the same method as described in Section A 9.3.4 we obtain:

$$h_{rad} = 117.9 \text{ W/m}^2\text{-°K } (20.77 \text{ Btu/hr-ft}^2\text{-°F}) \tag{A 12.2.9}$$

Using an average bulk combustion product gas temperature of 1712°K (2623°F) to evaluate properties in Equation A 12.2.4 we obtain:

$$h_{conv} = 37.19 \text{ W/m}^2\text{-°K} (6.55 \text{ Btu/hr-ft}^2\text{-°F}), \tag{A 12.2.10}$$

So that by Equation 12.2.2

$$h_g = 155.1 \text{ W/m}^2\text{-°K} (27.32 \text{ Btu/hr-ft}^2\text{-°F}) \tag{A 12.2.11}$$

The heat transfer coefficient for conduction through the tube wall, h_w, when referred to the outside surface is given by the following equation:

$$h_w = \frac{2\, k_w}{d_o \, \ell n \left(\frac{d_o}{d_i}\right)} \tag{A 12.2.12}$$

Using a thermal conductivity of 20.76 W/m-°K (12 Btu/hr-ft) or the 5.08 cm (2 in) od, 3.81 cm (1.5 in) id Croloy tubes, Equation A 12.2.12 yields

$$h_w = 2844 \text{ W/m}^2\text{-°K} (501 \text{ Btu/ft}^2\text{-hr-°F}) \tag{A 12.2.13}$$

Turning our attention to the forced convection heat transfer coefficient within the tubes, the situation is that of a supercritical fluid being evaporated through its pseudocritical temperature. Section A 9.3.5 of Appendix A 9.3 contains a discussion which is pertinent to this section. Briefly, the preferred equation is that of Kutateladze and Leontiev. If the very minor approximation of substituting bulk temperatures for film temperature is made when evaluating fluid properties, however, the equation reduces to the more familiar Dittus Boelter expression. Thus:

$$h_s = 0.023 \left(\frac{k_s}{d_i}\right) \left(\frac{G\ d_i}{\mu_s}\right)^{0.8} \left(Pr_s\right)^{0.4} \qquad \text{(A 12.2.14)}$$

Referring this heat transfer coefficient, which actually pertains to the tube inside diameter, to the outside diameter we obtain:

$$h_s' = h_s \frac{d_i}{d_o} \qquad \text{(A 12.2.15)}$$

In Equation A 12.2.14 the mass velocity is given by the equation:

$$G = \frac{4(m_s)}{\pi\ d_i^{\ 2}\ N_{circ}} \qquad \text{(A 12.2.16)}$$

Where N_{circ} is the number of parallel tubes in the water-wall section (504) and m_s is the total mass flow of primary steam for each of the four boilers [124.58 kg/s (0.9887×10^6 lb/hr)]. In Equation A 12.2.15, d_i is the inside diameter of the tubes [3.81 cm (1.5 in = 0.125 ft)].

Evaluating fluid properties at an average bulk value of 661°K (730°F), Equations A 12.2.14 through A 12.2.16 yield the

Table A 12.2.2 - Computation of Effective Area per Foot of Length for Heat Transfer on the Gas Side of the Water-Wall Evaporator Section

	Number of walls, N_W	Length of wall, (L_W), ft.	Tube pitch (P), ft.	Number of tubes, $Nt_{int} = (2)(N_W)(L_W)/P$ $Nt_{ext} = (N_W)(L_W)/P$	Tube Diameter, (d_o), in	View factor, F	Effective tube periphery, ft. $Per_{int} = (F)(\pi)(d_o)/12$ $*Per_{ext} = [(F)(\pi)(d_o)/2 + 1]/12$	Effective area per ft. Length of tube $A' = (N_t)(Per)$, ft^2/ft
Internal facets of the honeycomb	12	3	1/4	288	2	0.85	$\pi/6$	128.19
External facets of the honeycomb	18	3	1/4	216	2	1	0.345	74.52

Total 202.71 ft^2/ft

* In Table 12.2.2 the equation for Per is justified by the fact that only half the tube periphery is exposed to the gas plus the fact that a 2.54 cm (1 in) long fin of near 100% efficiency connects each tube on external facets.

following value for heat transfer coefficient from the inside wall to the steam, when referred to the outside tube wall.

$$h_s' = 4258 \text{ W/m}^2\text{-°K } (750 \text{ Btu/hr-ft}^2\text{-°F}) \qquad \text{(A 12.2.17)}$$

Combining the results stated by Equations A 12.2.11, A 12.2.13, and A 12.2.17 into Equations A 12.2.1, we obtain the following overall heat transfer coefficient referred to the outside of the tube:

$$h_o = 142 \text{ W/m}^2\text{-°K } (25.04 \text{ Btu/hr-ft}^2\text{-°F})$$

It is clear from the foregoing discussion that the overall heat transfer situation is controlled by the gas-side heat transfer; moreover, it is obvious that radiation is by far the most important factor on the gas side. Accordingly, when determining the required height of the water-wall section, the outside tube area per foot of height takes account of computed view factors. Thus, we use the effective area exposed to the radiating gas, which is smaller than the actual area by virtue of the view factors. Table A 12.2.2 shows the computational steps to arrive at the effective area per foot length of the water-wall evaporator section. Since we already have derived values for the overall heat transfer coefficient and the log mean temperature difference, it is then a simple matter to compute the required length of the section.

Recall that, consistent with our desire to cool the gas to 1366°K (2000°F) before exposing it to the crossflow tube banks, the water was raised from 644°K (700°F) feed temperature to 678°K (760°F) and that 41% of the 258.1 MWt transferred in the boiler is transferred to the water-wall section. Also, the log mean temperature difference over this section was computed to be 1240°K (1773°F) in Table A 12.2.1, and from Equation A 12.2.18 (and arguments leading thereto) the overall heat transfer coefficient in the water-wall section was seen to be 142.2 W/m^2-°K (25.04 Btu/hr-ft^2-°F). The average heat flux over the section can then be computed by the following equation:

$$\dot{q}_{e-i1} = h_o \text{ (LMTD)} = (25.04)(1773) = 4.44 \times 10^4 \text{ Btu/hr-ft}^2 \tag{A 12.2.19}$$

The subscript, e-i1 was first introduced in Figure A 12.2.3 and refers to the fact that after the section in question is cooled from some entering temperature (hence the e) to some first intermediate temperature of interest (hence the i1). The total area required for heat transfer is thus:

$$A_{e-i1} = \frac{Q_{e-i1}}{q_{e-i1}} \tag{A 12.2.20}$$

Finally, the length of this section can be determined using the result of Table A 12.2.2:

$$\ell_{e-i1} = \frac{A_{e-i1}}{\text{Per}} = \frac{8.139 \times 10^3}{202.71} = 40.15 \text{ ft} \tag{A 12.2.21}$$

This length would be rounded to 12.2 m (40 s/ft).

Three considerations lead to the decision to run all 504 of the water-wall tubes in parallel. These were:

- Headering is simpler.
- Under all load conditions the pseudocritical temperature is traversed in upflow.
- There was no incentive to raise the heat transfer coefficient inside the tubes, h_s, because it is already high and the overall heat transfer coefficient is dominated by the gas side.

An effect of running the water-wall tubes in parallel is to render the water-side pressure drop insignificant when compared to pressure drops sustained in the superheat bank and, later, in the reheat bank.

In a similar view, principally because of the large effective passage diameter, the gas pressure drop through the combustion tubes, which form the water-wall evaporator section, is very small compared with the pressure drops sustained in crossflow over the superheater and reheater banks. These low pressure drops over initial flow sections can, under certain circumstances, lead to flow instabilities. On the water side the situation can be corrected, if necessary, by orificing. On the gas side this would be difficult because of the need to preserve a good flame shape. Experience with conventional boilers, however, indicates that series gas-side flow instabilities do not occur.

A 12.2.5 Design of Crossflow Superheat and Reheater Tube Banks

From the point of view of determining their heat transfer and pressure drop performance, the crossflow tube banks in the pressurized boilers are essentially the same as the main evaporator and reheater banks of the coupling heat exchanger for the open-cycle MHD system.

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TABLE A 12.2.3–DESIGN OF FINISH SUPERHEAT AND REHEAT TUBE BANKS USING 2 IN. OD TUBES ON 4 IN. EQUILATERAL PITCH

Reheater	Main Evaporator	Units	Section
1206	1851	°F	Average Gas Temp, $\bar{T}_g$
0.236	0.173	lb/ft³	Gas Density at $\bar{T}_g$, ρ_g
29.32	33.2	ft/s	Max Gas Velocity $V_{max} = \frac{5.74}{\rho_g}$
34.91	39.02	Btu/hr ft² °F	Gas to Wall HTC, h_g See Eqn 9.3.29
0.00588	0.0080	psi/row	Gas Pressure Drop Per Row, $\Delta P/Row$ See Eqn 9.3.35
0.918 × 10⁶	0.989 × 10⁶	lb/hr	Total Steam Mass Flow, $\dot{m}_s$
35	35		Tubes Per Row, N_{Tube}
8	2		Number of Rows in Parallel, N_{Start}
280	70		Number of Parallel Circuits = $(N_{Tube})(N_{Start})$
248.76	1279	Btu/hr ft² °F	Wall to Steam HTC h_s See Eqn 9.3.33
186	958	Btu/hr ft² °F	h_s Refered to OD, $h_s' = \frac{d_i}{d_o} h_s$
20	20	Btu/hr ft² °F	Wall Thermal Conductivity k_w
834	834	Btu/hr ft² °F	Through Wall HTC $h_w = \frac{2 k_w}{d_o \ln\left(\frac{d_o}{d_i}\right)}$
28.51	35.88	Btu/hr ft² °F	Overall HTC $h = \frac{1}{\frac{1}{h_g} + \frac{1}{h_w} + \frac{1}{h_s'}}$
414.6	898	°F	Log Mean Temp Dif $LMTD = \frac{(\Delta T_{max} - \Delta T_{min})}{\ln\left(\frac{\Delta T_{max}}{\Delta T_{min}}\right)}$

Reheater	Main Evaporator	Units	Section
0.2368 × 10⁹	0.2823 × 10⁹	Btu/hr	Heat Transferred This Section, Q
20.033 × 10³	8.767 × 10³	ft²	Required Outside Tube Surface Area, $A_s = \frac{Q}{h \; LMTD}$
210.75	210.75	ft²	Area Provided Per Tube Row $A' = N_{tube}(\ell)\left(\frac{\pi d_o}{12}\right)$
95.06	41.58		Number of Tube Rows Required $N_{Row} = A_s/A'$
96	42		N_{Row} Upward Rounded to Make Evenly Divisible by N_{Start}
138	241.5	ft	Length of Tube Per Circuit, $\ell_{circ} = (N_{Row})(\ell)/N_{Start}$
0.312	0.864	psi/ft	Steam Pressure Drop Per Ft of Tube Length, $\Delta P/ft$ See Eq A9.3.41
43.06	208.66	psi	Total Steam Pressure Drop, $\Delta P_s = (\ell_{circ})(\Delta P/ft)$
	208.66	psi	Total Gas Pressure Deop $\Delta P_g = (\Delta P/row)(N_{row})$
0.9039		psi	Combined Evaporator and Reheater Gas, ΔP
			Comment
Rows 96 Tubes/Row 35 Starts 8 Tubes/Circuit 12 Row Length, ft 11.5	Rows 42 Tubes/Row 35 Starts 2 Tubes/Circuit 21 Row Length, ft 11.5		Summary of Tube Bank Size Parameter

This steam generator was described in detail in A 9.3 The reader is referred to A 9.3.5 where every equation starting at Equation A 9.3.26 and proceeding through Equation A 9.3.48 applies to the superheat and reheat tube banks of the supercharged boiler also. The one exception to this is Equation A 9.3.31 which is replaced in the system of equations by the equation to be derived below.

For the pressurized boiler both crossflow tube banks are such that each row contains 35 tubes of 5.08 cm (2 in) outside diameter and 3.51 m (11.5 ft) length placed in parallel array on a 10.16 cm (4 in) pitch. The total gas mass flow rate which must flow over and betwen these tubes in each of the four pressurized boilers is 172.1 kg/s (1.365×10^6 lb/hr). Using Equation A 9.3.30 and the above parameters as a basis, the new equation for V_{max} is:

$$V_{max} = \frac{5.74}{\rho_g} \text{ ft/s} \qquad \text{(A 12.2.22)}$$

Equation A 12.2.22 replaces Equation A 9.3.31 in the calculation scheme used to determine the required number of tube rows and the number of individual circuits in order to satisfy the heat exchange and pressure drop requirements of both the superheater and reheater tube banks. The route taken by this calculation procedure and the resulting configuration of the tube banks is summarized in Table A 12.2.3 which follows.

Appendix A 12.3
PRESSURIZED BOILER PRICE ANALYSIS

Table 12.15 is a breakdown of the component costs of the base case pressurized boiler based on the heat transfer analysis developed in Appendix A 12.2. The boiler costs will vary, of course, as the power cycle parameters are varied. The following development derives an expression for the boiler cost in terms of the base case cost and the pertinent cycle parameters.

For pressure drop comparable to the base case, the mass velocity on the hot gas side should be kept constant in the boiler. Because the gas turbines ingest a constant airflow rate, the mass flow rate through the boiler is essentially constant. From continuity:

$$\dot{M}_g = \rho\ A\ V \propto \rho\ \frac{\pi}{4} D^2\ V \qquad \text{(A 12.3.1)}$$

where $\dot{M}_g$ = gas mass flow rate

ρ = gas density

D = vessel diameter

V = gas velocity

Since the temperature on the gas side is approximately constant, ρ is proportional to the gas pressure P. Because $\dot{M}_g$ and V are constant:

$$D \propto \sqrt{1/\rho} \qquad \text{(A 12.3.2)}$$

Since D equals 6.096 m (20 ft) when P is 1.013 MPa (10 atm) the constant of proportionality is 63.25. The shell labor cost, which results primarily from the welding operation, is a function of the thickness, t, of the shell and the length of the weld, which in turn is proportional to the shell diameter. Referring to the base case whose labor cost is \$310,000,

$$\text{Shell Labor Cost} = (\text{base cost}) \left(\frac{\text{thickness factor}}{\text{base case thickness factor}}\right)\left(\frac{D}{D_{base}}\right) \quad \text{(A 12.3.3)}$$

where the thickness factor is approximated by the equation $1 + 2\ (t - 1)$ and the base case thickness factor equals 2.

From stress analysis, the thickness of the shell is given by

$$t = \frac{PD}{2\sigma} \quad \text{(A 12.3.4)}$$

where σ is the allowable tensile stress. Substituting for t and D, the shell labor cost (SLC) in millions of dollars is:

$$SLC = (0.310) \left\{ \frac{1 + 2\left[\frac{63.25\ \sqrt{P}}{2\sigma} - 1\right]}{2} \right\} \left(\frac{63.25}{20\sqrt{P}}\right) \quad \text{(A 12.3.5)}$$

where P is in atmospheres. The shell material cost (SMC) in millions of dollars is given by Equation A 12.3.6 for a base cost of $350,000.

$$SMC = (\text{base cost}) \left(\frac{t}{1.5}\right)\left(\frac{D}{20}\right)$$

$$= (0.350) \left(\frac{63.25\ \sqrt{P}/2\sigma}{1.5}\right)\left(\frac{63.25}{20\ \sqrt{P}}\right) \quad \text{(A 12.3.6)}$$

The heat exchanger components can be considered according to the nature of the heat transfer process within them.

In the combustor/evaporator section the heat transfer by radiation prodominates. The radiation heat transfer is affected somewhat by pressure through the effect it has upon the emissivity of carbon dioxide and water vapor. Due to limited data the effect is difficult to quantify above 506.5 kPa (5 atm) and becomes progressively weaker as pressure increases. Accordingly, it will be assumed that the combustor/evaporator cost is a constant for the range of conditions encountered.

The superheater and reheater units are banks of tubes with the hot gas passing over the tubes in cross flow. Neglecting radiation and making the assumption that the heat transfer rate is gas-side limited, the heat transfer area is inversely proportional to the gas-side convection heat transfer coefficient. The convection coefficient is given by:

$$h = 0.33 \left(\frac{Gd}{\mu}\right)^{0.6} Pr^{0.33}$$

where the tube diameter, d, the viscosity, μ, and the Prandtl Number, Pr, are constant since the temperature level is essentially constant. The mass velocity, G, equals the gas mass flow rate, $\dot{M}_g$, which is constant divided by the open flow area. Since the tube diameter and pitch are constant, the open area is proportional to the vessel diameter, D, squared. But since the square of the vessel diameter is inversely proportional to the gas pressure, P, as shown previously, the convection heat transfer coefficient can be written

$$h \propto (P)^{0.6}$$

Now the heat transfer area, and, therefore, heat exchanger cost, is given by the equation

$$A = \frac{Q}{h\Delta T}$$

Since ΔT is constant, the steam and gas temperature profiles at design point will be maintained essentially constant; then,

$$A \propto \frac{Q}{(P)^{0.6}}$$

but Q is proportional to the mass flow rate of steam, $\dot{M}_s$, so that

$$A \propto \frac{\dot{M}_s}{(P)^{0.6}}$$

With this information and the cost breakdown of the several elements of the base case boiler the following equation for the price (in millions of dollars) of the boiler is found:

$$\text{Boiler price} = 0.978 + 0.566 \left\{ \frac{1 + 2\,[0.4743\ \sqrt{P} - 1]}{\sqrt{P}} \right\} + \frac{(10^6)\ (\dot{M}_s)\ (TF)}{(P)^{0.6}} \qquad \text{(A 12.3.7)}$$

where P is in atmospheres, $\dot{M}_s$ is in millions of pounds per hour, and TF is a temperature factor multiplier to account for a materials cost increase of the convection bank tubes for the higher steam temperatures. This factor is based on similar cost increments determined for fluidized bed boilers. As a function of steam temperature, the temperature factor is as follows:

T_{steam}, °F	TF
1000	1.0
1200	1.88
1400	3.84

Appendix A 12.4

HOT GAS PIPE REFERENCE CONFIGURATION COSTS

Table 12.4.1 - Hot Gas Pipe Reference Configuration Costs - Size 1

Size: 3 ft, id
Length: 680 ft

Pressure: 150 psig
Max. Temperature: 1800°F

	Weight, lb	Mtl. Cost, $/Lb	Lbr. Cost, $/Lb	Total Cost, $/Lb	Material Cost x 10^{-3} $	Installation Cost x 10^{-3} $	Total Cost x 10^{-3} $
1. Carbon Steel Pipe	160,684	0.51	0.56	1.07	82	90	172
2. Incoloy Liner, 1/4 inch thick	67,800	3.26	1.76	5.02	221	120	341
3. Refractory, 9 in TK x HN-HI-LI Harbison Walker	258,000	0.16	0.22	0.38	41	57	98
4. Lining Anchors, @ 5 lb/ea	38,500	0.31	0.31	0.62	12	12	24
5. Refractory Anchors, @ 5 lb/ea	57,650	0.31	0.31	0.62	18	18	36
6. Structural Steel (truss)	240,000	0.30	0.08	0.38	72	18	90
7. Concrete (truss)					21	11	32
8. Expansion Joints (4)	Allow				140	—	140
					607	326	933
Contingency 15%							140
							1,073

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Table 12.4.2 – Hot Gas Pipe Reference Configuration Costs – Size 2

Size: 3 ft, id — Pressure: 300 psig

Length: 680 ft — Max. Temperature: 1800°F

	Weight, lb	Mtl. Cost, $/Lb	Lbr. Cost, $/Lb	Total Cost, $/Lb	Material Cost x 10^{-3} $	Installation Cost x 10^{-3} $	Total Cost x 10^{-3} $
1. Carbon Steel Pipe	315,000	0.48	0.54	1.02	150	173	323
2. Incoloy Liner, 1/4 inch thick	67,800	3.26	1.76	5.02	221	120	341
3. Refractory, 9 in TK x HN-HI-LI Harbison Walker	258,000	0.16	0.22	0.38	41	57	98
4. Lining Anchors, @ 5 lb/ea	38,500	0.31	0.31	0.62	12	12	24
5. Refractory Anchors, @ 5 lb/ea	57,650	0.31	0.31	0.62	18	18	36
6. Structural Steel (truss)	240,000	0.30	0.08	0.38	72	18	90
7. Concrete (truss)					21	11	32
8. Expansion Joints (4)	Allow				140	—	140
					675	409	1,084
Contingency 15%							163
							1,247

Table 12.4.3 - Hot Gas Pipe Reference Configuration Costs - Size 3

Size: 8 ft, id — Pressure: 150 psig

Length: 680 ft — Max. Temperature: 1800°F

	Weight, lb	Mtl. Cost, $/Lb	Lbr. Cost, $/Lb	Total Cost, $/Lb	Material Cost x 10^{-3} $	Installation Cost x 10^{-3} $	Total Cost x 10^{-3} $
1. Carbon Steel Pipe	707,200	0.35	0.55	0.90	248	389	637
2. Incoloy Liner, 1/4 inch thick	176,500	3.34	0.68	4.02	586	120	706
3. Refractory, 9 in TK x HN-HI-LI Harbison Walker	599,000	0.16	0.22	0.38	94	133	227
4. Lining Anchors, @ 5 lb/ea	102,000	0.30	0.30	0.60	31	31	62
5. Refractory Anchors, @ 5 lb/ea	122,000	0.30	0.30	0.60	36	36	72
6. Structural Steel (truss)	720,000	0.28	0.095	0.375	202	69	271
7. Concrete (truss)					40	20	60
8. Expansion Joints (4)	Allow				212	—	212
					1,449	798	2,247
Contingency 15%							337
							2,584

Table 12.4.4 - Hot Gas Pipe Reference Configuration Costs - Size 4

	Size: 8 ft, id Length: 680 ft			Pressure: 300 psig Max. Temperature: 1800°F			
	Weight, lb	Mtl. Cost, $/Lb	Lbr. Cost, $/Lb	Total Cost, $/Lb	Material Cost x 10^{-3} $	Installation Cost x 10^{-3} $	Total Cost x 10^{-3} $
1. Carbon Steel Pipe	1,655,000	0.37	0.47	0.84	619	785	1404
2. Incoloy Liner, 1/4 inch thick	176,500	3.34	0.68	4.02	586	120	706
3. Refractory, 9 in TK x HN-HI-LI Harbison Walker	599,000	0.16	0.22	0.38	94	133	227
4. Lining Anchors, @ 5 lb/ea	102,000	0.30	0.30	0.60	31	31	62
5. Refractory Anchors, @ 5 lb/ea	122,000	0.30	0.30	0.60	36	36	72
6. Structural Steel (truss)	800,000	0.28	0.095	0.375	224	76	300
7. Concrete (truss)					44	23	67
8. Expansion Joints (4)	Allow				212	—	212
					1,846	1,204	3050
Contingency 15%							458
							3508

Appendix A 12.5

STACK GAS COOLER COST BREAKDOWN

(Costs in dollars are shown for 1/2 million square foot unit)

	Material	Labor	Total
Finned Tubing and Module Assembly	1,160,000	660,000	1,820,000
Boiler Plate	10,000	15,000	25,000
Header Piping	10,000	5,000	15,000
Module Erection and Support Steel	5,000	15,000	20,000
Subtotals	1,185,000	695,000	1,880,000
Contingency: 15%			282,000
		TOTAL	2,162,000

Appendix A 12.6

THERMODYNAMIC GAMESMANSHIP/COMBINED CYCLES

If the "cost of apparatus" is defined as the sum of O&M and capital charges, then it is easy to show that generating cost is minimum when the derivative of heat rate to "cost of apparatus" is proportional to minus the inverse of fuel cost. Higher fuel cost allows the generation optimizer to spend more dollars on efficiency-raising apparatus and, thus, diminishes the importance of specific work compared to efficiency. The efficiency is the product of the internal reversbility of the cycle and the ratio of input availability to enthalpy. This last ratio is the ratio of:

$$\int_{T_1}^{T_2} C_p \left(1 - \frac{T_o}{T}\right) dT \qquad \text{(A 12.6.1)}$$

to

$$\int_{T_1}^{T_2} C_p \, dT \qquad \text{(A 12.6.2)}$$

Thus the vital importance to efficiency of beginning the heat addition to cycle at high temperature as well as ending it so is highlighted. Of course the importance of low temperature of heat rejection (T_o) is equally pointed up. Such "improvements," however, must not be made at the expense of internal reversibility, or reversible success may turn to actual failure.

A simple-minded example may be worthwhile. A cycle is designed in which the fluid is heated from an enthalpy of 2.3255 to 3.2557 MJ/kg (1000 to 1400 Btu/lb) and the entropy increases in the heating from 4.579 to 5.710 kJ/kg-°K (1.094 to 1.364 Btu/lb-°F). The heat rejection from the cycle is assumed to take place at 306°K (90°F). The availability addition is 0.5849 MJ/kg [400 - (550)(0.27) = 251.5 Btu/lb]. If the cycle is reversible this will be the specific work. We find, however, that pipe and heat exchanger pressure drops and turbine and compressor inefficiencies result in summed entropy increase of 3.828 J/kg-°K (0.09145 Btu/lb-°F) in these adiabatic processes internal to the cycle. The lost work due to internal irreversibility is then 0.11697 MJ/kg [(550)(0.09145) = 50.3 Btu/lb]. The work then becomes 0.4690 MJ/kg [251.5 - (50.3) = 201.2 Btu/lb] and the reversibility index is (201.2/251.5) = 0.80. The efficiency is (201.2/400) = 0.503. This is the same as:

$$\eta_B \left(\frac{\Delta h_i - T_o \Delta s_i}{\Delta h_i}\right) = 0.8 \left(\frac{400 - (550)(0.27)}{400}\right) = 0.503 \quad \text{(A 12.6.3)}$$

Now a way is found to increase the fluid temperature into the input heat exchanger. Typically, the initial enthalpy goes to 2.6953 MJ/kg (1159 Btu/lb) and entropy is 5.048 kJ/kg-°K (1.206 Btu/lb-°F). The hot-end conditions are unchanged. The availability addition becomes 0.3584 MJ/kg [241 - (550)(0.158) = 154.1 Btu/lb]. The net work becomes 0.2414 kJ/kg (103.8 Btu/lb) and the reversibility 0.6736. The efficiency becomes [(154.1 - 50.3)/241] = 0.43. The previous reversible efficiency was (251.5/400) = 0.6288, and the new reversible efficiency is (154.1/241) = 0.6394. Merely to break even on the change:

$$\eta_1 = \frac{E_2 \ (\Delta A_1 - \Delta A_2)}{E_2 \Delta A_1 - E_1 \Delta A_2} = 0.9744 \qquad \text{(A 12.6.4)}$$

Let us define some characterizing variables of Brayton and Rankine cycles preparatory to deriving some efficiency expressions in algebraic form which cast much light on the question of concept guidance to apply to parametric search.

Symbol	Meaning
η_B	Reversibility index Brayton = $\dfrac{\text{Realized Work}}{\text{Availability in}}$
η_R	Reversibility index Rankine
i	Subscript-Brayton heat input profile
1	Subscript-Brayton output profile
2	Subscript-Rankine input from Brayton (nonpostfired)
T	Characteristic temperature of heat exchange (or firing) process = $\Delta h/\Delta s$
T_a	Characteristic temperature of supplemental firing to Rankine cycle
Δh_s	Stack enthalpy less ambient ("exhaust loss")
E	Ideal thermal efficiency - reversible/enthalpy addition.

The efficiency of a nonsupplementary-fired combined cycle is (see Subappendix AA 12.6.1):

$$\frac{\text{(h to work)}}{\Delta h_i} = \eta_R \frac{T_2 - T_o}{T_2}\left[1 - \eta_B \left(\frac{T_i - T_B}{T_i}\right)\right] + \eta_B \left(\frac{T_i - T_B}{T_i}\right)$$

$$- \eta_R \left(\frac{\Delta h_s}{\Delta h_i}\right)\left(\frac{T_2 - T_o}{T_2}\right) = \eta_c \left(\frac{T_i - T_o}{T_i}\right) \qquad \text{(A 12.6.5)}$$

where η_c is the net reversibility index of the combined cycle. If supplementary firing is added:

$$\text{Efficiency} = \frac{1}{(1 + \rho)} (\varepsilon_o + \varepsilon_1\rho) = \frac{\varepsilon_o}{1 + \rho} \left[1 + \rho \left(\frac{\varepsilon_1}{\varepsilon_o}\right)\right] \tag{A 12.6.6}$$

where ρ is the ratio of postfired heat to original, ε_o is the nonpostfired efficiency, and ε_1 is η_R $(T_a - T_o/T_a)$. Since ρ is positive, the efficiency increases only if $\varepsilon_1 > \varepsilon_o$. This may be obtained even if $T_a <$ T_1 if η_R is sufficiently larger than η_c. Optimum cycles will show values of η_R approaching 0.90 and η_B around 0.65. The keystone No. 1 steam power station has an apparent η_R of 0.90 and our open gas turbine cycles run around 0.65 (see Subappendix AA 12.6.2). These do not include mechanical and electrical losses. The η_B is primarily a function of specific work; and η_R varies little but is higher with exhaust cooler than with extractive feed heating.

The nonpostfired cycle reversibility is best (other things being equal) if the Rankine cycle is operated in the critical range and if the mass flows of the two cycles are such that a reasonably linear, counterflow heat exchanger ("waste heat boiler") is obtained. At present levels of metallurgical limits on temperatures and pressures the Rankine stream cannot be "waste-heated" far into the critical region. But the temperature at this point is high enough that fired heating into the superheat field yields an attractive value of characteristic temperature, T_a of the last paragraph, when combined with the high reversibility index, η_R, of the Rankine cycle. As higher Brayton firing temperatures become possible, the optimum Rankine pressure increases; if this is dismissed on practical grounds, the postfired heat ratio, ρ, declines.

In short the issue is that the optimum combined cycle is likely to have the following characteristics:

- Supercritical Rankine pressure

- Mass flow ratio of the order of 4 to 1
- No intercooling (indeed, modest prewarming or better, interheating may be beneficial to Brayton reversibility with reduction of pressure ratio)
- High supplementary firing ratio (declining with Brayton temperature)
- Multiple Rankine reheat or steam-steam recuperation with few reheats (the purpose of either is to raise the temperature at the beginning of fired reheat)
- Modest Brayton pressure ratio or reheated high pressure ratio Brayton
- Extractive feed heating below the prescribed stack temperature but not above it (due allowance for heat exchanger approach)
- No Brayton recuperation (as a consequence of the invariably better reversibility of the Rankine cycle than the Brayton).

It is clear that the gas generator/free power turbine Brayton arrangement is superior to the all-synchronous Brayton, both for part-load performance and for the provision of bonus reheat capability. Brayton reheat is obviously thermodynamically superior to equal heat addition through postfiring. Brayton reheating may be performed with primary (unvitiated) air supplied from compressor bleed.

The steam-steam recuperator mentioned in the list is, of course, a heat exchanger located between a cold reheat line and the following reheat turbine group exhaust. Since it returns the expansion line to about cold reheat temperature, equivalent to reheating the original expansion line to cold reheat temperature at reheat turbine exhaust pressure, one must be sure that the resulting end point is not too wet. This obtains if the throttle temperature is adequately high and the reheat turbine exhaust pressure is adequately low.

The steam recuperator was originally associated with a concept called Balanced Pressure Superreheat which is described in the Westinghouse ECAS Proposal under "Advanced Steam." It is really a means of combined-cycle improvement since it requires about a 3.0398 MPa (30 atm) pressurized furnace for a reasonable minimum reheat pressure of 3.1026 MPa (450 psi) abs. This concept should be parametrically explored under Section 6, since it obtains its full leverage only without high-pressure extraction as is obtained with full flow exhaust feed heating. Atmospheric fired superreheating is a near thermodynamic equivalent and should be considered practical to about the same temperature level as closed-cycle gas heaters.

We can see little plausbility in such NASA-specified concepts as "repowering," "pressurized furnace closed cycles," and "organic bottomed gas turbines."

The remark on organic bottomed gas turbines is based on stability and inventory cost. It is reasonably clear that a low critical pressure fluid of suitable critical temperature would be valuable on thermodynamic grounds since good linear heating is obtained at reduced pressures, Pr, of 3 or thereabouts.

The candidates for combined nonsteam cycle study are ammonia, sulfur-dioxide, and the light hydrocarbons, with carbon-dioxide a rather implausible trailer. Of these, sulfur-dioxide seems to be the clear choice on the grounds of reasonable critical pressure [7.881 MPa (1143 psi) abs], critical temperature well above sink [430.7°K (315.5°F)] so that isothermal heat rejection is obtained, good stability and acceptable cost (in fact it is extractable from the coal fuel either in treatment or postcombustion). It is true that the entropy of the saturated vapor at 310.9°K (100°F) is approximately equal to that of the 24.132 MPa (3500 psi) abs vapor at 700°K (800°F), so that even at this high Pr (3.06) unreheated expansion becomes moist only if the throttle temperature is somewhat less than 700°K (800°F). The implication of this fact is that sulfur-dioxide will probably be found most useful in waste heat rather than in supplementary fired cycles, since high throttle temperature or reheated cycles will require vapor-liquid recuperation and can raise the stack loss. A sulfur dioxide combined cycle at optimum will probably be of a rather conventional waste heat pattern, although highly supercritical. It should provide highly competitive efficiency to optimized gas-steam; in fact, we would expect that for high-pressure ratio cycles with gas turbine exit temperature in the range of 616 to 728°K (650 to 850°F) it will be definitely superior to steam if high sulfur dioxide throttle pressure is used to improve the reversibility of the intercycle heat exchanger.

This discussion may be a little startling to the gas turbine-oriented mind which has been acclimated to the concept of an existing open gas turbine frame whose large exhaust heat loss is to be converted to work (or process steam), as well as it can with no major effects on the gas turbines. Base-load optimization must begin with no frozen apparatus or cycle parameter concepts derived from either previous gas turbine practice or previous orthodox steam utility practice. The need for supercritical Rankine pressure is derived from the need for thermally coupling the Rankine plant to the Brayton plant as reversibly as possible. Supplementary firing is then used to, and only to, the extent that it satisfies the physical requirements of the Rankine (provision of reasonable end point), improves the thermodynamics of the combined plant (by reason primarily of the higher Rankine reversibility), and improves generation cost. It is important to understand the trade-offs involved in concept-optimizing a gas-steam plant. Steam is an unusual vapor in that its saturated entropy at around 311°K (100°F) is unusually large compared to its critical entropy. Thus, the analyst is confronted with the need on the one hand to employ supercritical steam to minimize the opening of the hot end ΔT (with the peaking of specific heat at the rectilinear diameter or with subcritical evaporation), and on the other to attain high $\Delta h/\Delta s$ in the supplementary heating necessary to move the expansion line to a reasonable end point. Multiple reheat or steam-to-steam recuperation with single reheat are the means, and high level reheating is a coupled need. Likewise, in attempting to attain plausible improvement of the "conventional" steam plant, it is necessary to increase the mean temperature of heating at throttle pressure by increasing feed temperature without offsetting degradation of the reversibility of the feed heating, and to increase the mean temperature of reheating by multiple reheat or by steam-to-steam recuperation with a single reheat, with the hot reheat temperatures driven as high as is plausible in fired heat exchangers.

In the combined cycle it is clear that:

- The transfer of heat from Brayton to Rankine in the form of postexpansion exhaust heat (waste heat) has the function of as reversibly as possible extending the sink temperature of the cycle to the 311°K (100°F) neighborhood. The thermal efficiency of the Rankine cycle per se is of no importance so long as this is done. Very nearly this requires that the Brayton cycle be designed to maximize its reversibility index $[(\text{work}/\Delta h_i)(T_i - T_1)]$ rather than its specific work or ordinary efficiency. This follows from the fact that the Rankine reversibility is largest, so the Brayton must degrade its input heat as little as possible.
- Any supplementary heating of the Rankine cycle must be done at such a mean temperature, T_a, that the incremental thermal efficiency of its use is higher than that of the combined cycle without its use. T_a may still be less than T_i because $\eta_R > \eta_c$.

As a consequence, it is reasonably clear that combined cycle thermodynamic gamesmanship requires in general that:

- The Brayton reversibility index be kept near maximum. This, of course, is a function of component polytropic efficiencies, pressure ratio(s), pressure losses, and extraction heater approach and spread.

- The Brayton heat addition takes place at as large a $[\Delta h/(\Delta s\ T_1)]$ as possible. For any specified turbine inlet temperature this factor increases with increasing pressure ratio, but the reversibility index declines with increased pressure ratio. The conflict with the previous requirement will produce an optimum which may be improved by such unorthodox measures as recuperative compressor prewarming or interwarming of modest amount.

- Brayton reheat be employed to the extent economic and practical factors permit. Reheat combustion primary air may be fresh compressor bleed air if beneficial in a practical sense. Brayton reheat is, of course, superior to the same fuel used in supplementary firing of the Rankine.

- The Rankine be operated at as high a reduced dimensionless pressure, $Pr = P/Pc$, as possible to permit linearizing the Brayton-to-Rankine waste heat exchange. Sulfur dioxide should be considered particularly for nonsupplementary-fired combined cycles.

- The Rankine waste heating profile should proceed to as high a temperature as possible (supercritical), if supplementary firing is used, so the incremental supplementary heat efficiency can be made larger than that of the base unfired cycle.

- For cases in which Rankine reheating is used, the cold reheat temperature should substantially equal or better exceed the waste heating temperature. This implies high remaining superheat at reheat pressure or the use of steam-to-steam recuperation. The latter is effective in the sense of obtaining significant reheat enthalpy increase only if the hot reheat temperature is rather high. The balanced pressure reheater was invented as a plausible mechanism for relief of stress-temperature problems at high reheat temperature. No lack of plausibility is seen, however, in a [say 3.0398 MPa (30 atm) abs] steam heater with atmospheric furnace compared to a closed-cycle gas heater of equal pressure and temperature.

- Extractive feed heating is used in the Rankine only below the acid dew point (stack) determined limit of exhaust cooler feed heating. This implies, as does linear waste heat transfer, a mass flow ratio around 4 to 1. It has the further advantage in a superreheat cycle of providing high mass flow leverage for the high-temperature reheating event.

The following example is a rather simple-minded one to illustrate a method of rapidly surveying the parametric field in order to block out the areas of interest for more detailed (but limited in number) examinations:

Example: Postfired Cycle

Gas Turbine (air cycle-fuel mass not accounted)

Pressure ratio	-	15/1
Compressor efficiency	-	0.89
Turbine efficiency	-	0.90
$\Delta P/P$	-	0.08
Exhaust cooler out	-	275°F
Stack	-	235°F
Prewarm temperature	-	100°F
Firing temperature	-	1800°F

Point	Pr	h	ϕ	T°R	
Comp. in	1.5742	133.86	0.6095	560	
Rev. comp.	23.613	290.03			
Comp. out		309.33	0.811	1270	$\Delta h_i = 268.18$
Turbine in	286.6	577.51	0.96626	2260	$\Delta h/\Delta s = 1727.3 = T_i = \frac{577.51-309.33}{0.96626-0.811}$
Turbine rev.		279.62			
Turbine out		309.41	0.811	1271	
Exhaust cooler out		176.03	0.67501	735	$\Delta h/\Delta s = \frac{309.41-133.86}{0.811-0.6095} = 871.22 = T_1$
Stack		166.36	0.66147	695	
Ambient		124.27	0.59173	520	stack loss=166.36-124.27=Δh_e

$$\text{Net Work} = (577.51-309.41) - (309.33-133.86) = (268.1-175.47) = 92.63$$

$$\eta_B = \frac{(92.63)(1727.3)}{268.18(1727.3-871.22)} = 0.697$$

Steam cycle 3500 psi/1000°F/1000°F/1200°F; Cold reheat about 650°F

Point	T	P	h	s	
Exhaust cooler in	690	4000	207.0	0.3335	
out	1180	3600	875.8	1.0325	$T_2 = 956.8°F$ $T_o = 555°R$

$$\text{Unfired Eff.} \approx 0.9 \left(\frac{956.8-555}{956.8}\right) \left[1 - 0.697 \left(\frac{1727.3-871.22}{1727.3}\right)\right.$$

$$\left. + 0.697 \left(\frac{1727.3-871.22}{1727.3}\right) - 0.9 \left(\frac{42.09}{268.18}\right)\left(\frac{956.8-555}{956.8}\right)\right]$$

$$= 0.1305 + 0.3454 - 0.0593 = 0.4166$$

$$T_A > \frac{(0.9)(555)}{(0.9-0.4166)} = 1033°R \text{ which is easily accomplished.}$$

At 24.821 MPa (3600 psi) abs from 656 to 811°K (1180 to 1460°R, 720 to 1000°F),

$$\frac{\Delta h}{\Delta s} = \frac{(1692-875.8)}{(1.632-1.0325)} = 1361.5°R$$

for which the incremental efficiency is 0.533.

At 6.894 MPa (1000 psi) abs reheating from 617 to 922°K (1110 to 1660°R, 650 to 1200°F),

$$\frac{\Delta h}{\Delta s} = \frac{(1618.4-1290.1)}{(1.7256-1.4833)} = 1355°R$$

where the incremental efficiency is 0.531.

The overall fired heating,

$$\frac{\Delta h}{\Delta s} = \frac{1144.5}{0.8418} = 1359.6 \quad \varepsilon_i = 0.5326$$

$$\text{Mass Ratio } \frac{\text{steam}}{\text{air}} = \frac{(309.41-176.03)}{(875.8-208.61)} = 0.2$$

$$\rho = 0.2 \left[\frac{(1692-875.8) + (1618.4-1290.1)}{(577.51-309.33)}\right] = 0.8535$$

$$\text{Efficiency} = \frac{1}{1.8535} [0.4166 + (0.5326)(0.8535)] = 0.4700$$

Postfiring is seen to have increased the combined-cycle efficiency by some 12.9% (from 0.4166 to 0.47), a benefit due to two circumstances:

- The postexpansion Brayton heat has been rather reversibly delivered to the Rankine and so balanced that a high feed temperature is attained [656°K (1180°R, 720°F)]. Thus, the primary Rankine-fired heating is moved up to a respectable $\Delta h/\Delta s$.

- The Rankine expansion line is adjusted to use a respectable cold reheat temperature [617°K (1110°R, 650°F) here] for the same purpose. This requires a relatively high-pressure first reheat; and if only one reheat is used, the hot reheat temperature must be very high if a satisfactory expansion line end point (ELEP) is to be achieved. If one assumes that superreheat is plausible, then a steam recuperator will extend the thermodynamic gain and assist in optimizing the ELEP. If low hot reheat temperature [811°K (1000°F)] is assumed then, of course, multiple reheat is the orthodox and correct method of improving the cold reheat temperatures. Parenthetically, very high steam temperature is probably plausible only at relatively low pressure, 24.132 MPa/811°K/1033°K (3500 psi/1000°F/1400°F) is much more plausible than 24.132 MPa/1033°K (3500 psi/1400°F), whether the balanced pressure reheat concept is used or not. The steam recuperator will be found most useful both in obtaining satisfactory cold reheat temperature for a single low-pressure reheat and in obtaining reasonable ELEP.

Subappendix AA 12.6.1

COMBINED-CYCLE EFFICIENCY

Let us first try to be very clear on the definition of "reversibility index" of a cycle. It is the ratio of actual efficiency to the efficiency of a reversible cycle with the same heat addition and heat dissipation profiles. From the second law of thermodynamics this is the same as the ratio of the specific work to the flux of availability ($\Delta h - T_o \Delta s$) into the cycle. T_o is the thermodynamic temperature of heat dissipation, which is the ratio $\Delta h/\Delta s$ over the dissipation profile. For the orthodox condensing Rankine, T_o is, of course, the effective condensing temperature. The sources of availability loss (internal) are, of course, turbulent entropy growth in expanders, compressors, ducts, and so on and net entropy gains in heat exchange. Lower specific work of expansion and higher recycle work (of compression) in the Brayton cycle impose on it a lower reversibility index via the turbulence leverage in these processes imposed upon low specific net work as compared to the Rankine.

The efficiency of a combined cycle without supplementary firing of the Rankine cycle is derived thus:

The Brayton cycle has reversibility index η_B, is heated to enthalpy increase Δh_i and entropy increase Δs_i at thermodynamic temperature $T_i = \Delta h_i/\Delta s_i$. It is cooled at thermodynamic temperature T_1 by the transfer to the Rankine of Δh_1 carrying Δs_1 and then in precooler (or stack in the internally-fired Brayton with suitable adjustments for the fuel mass addition from the burner on) to the compressor inlet temperature or ambient. Note that a precooler is not necessarily used in a combined-closed cycle if a sufficient high degree of coupling heat exchanger linearity is attained by means previously described. The "stack" or precooler heat and entropy are Δh_s and Δs_s. The thermodynamic cooling temperature of the Brayton cycle is:

$$T_B = \left(\frac{\Delta h_1 + \Delta h_s}{\Delta s_1 + \Delta s_s}\right)$$

so the Brayton specific work (closed cycle used for model simplicity) is:

$$W_B = \eta_B \left(\Delta h_i\right)\left(\frac{T_i - T_B}{T_i}\right)$$

The Rankine cycle recives heat from the Brayton at $T_2 = \Delta H_2/\Delta S_2$, where capitals indicate Rankine fluid property changes and T_2 is necessarily lower than T_1. The work of the Rankine cycle (specific to Brayton mass flow) is:

$$W_R = \eta_R \left(\frac{T_2 - T_o}{T_2}\right)\left[\Delta h_i - W_B - \Delta h_s\right]$$

$$= \eta_R \left(\frac{T_2 - T_o}{T_2}\right)\left[\Delta h_i - \Delta h_s - \eta_B\, \Delta h_i \left(\frac{T_i - T_B}{T_i}\right)\right]$$

The total work is:

$$W = \eta_R \left(\frac{T_2 - T_o}{T_2}\right)\left\{\Delta h_i \left[1 - \eta_B \left(\frac{T_i - T_B}{T_i}\right)\right] - \Delta h_s\right\} + \eta_B \left(\Delta h_i\right)\left(\frac{T_i - T_3}{T_i}\right)$$

The efficiency is $W/\Delta h_i$:

$$\varepsilon = \eta_R \left(\frac{T_2 - T_o}{T_2}\right) \left[1 - \eta_B \left(\frac{T_i - T_B}{T_i}\right)\right] + \eta_B \left(\frac{T_i - T_B}{T_i}\right) - \eta_R \left(\frac{T_2 - T_o}{T_2}\right)\left(\frac{\Delta h_s}{\Delta h_i}\right)$$

Now consider a combined cycle with Brayton heat Q_o at efficiency ε_o and no supplementary firing. Pay no attention to the pra al implications of such an initial model as, for example, a throttle steam condition of 24.132 MPa/644°K (3500 psi/700°F). Now add additional heat Q_1 to the Rankine cycle in such ways as to make the Rankine cycle plausible. This is done at an incremental efficiency ε_1, which is the product of η_R and $(T_A - T_o)/T_A$, where T_A is the thermodynamic temperature ($\Delta H/\Delta s$) at which the heat is added and T_o the Rankine sink temperature. The total work is:

$$W = \varepsilon_o \left(Q_o\right) + \varepsilon_1 \left(Q_1\right)$$

and the efficiency:

$$\frac{W}{(Q_o + Q_1)} = \varepsilon_o \left(\frac{Q_o}{Q_o + Q_1}\right) + \varepsilon_1 \left(\frac{Q_1}{Q_o + Q_1}\right)$$

Let:

$$\frac{Q_1}{Q_o} = \rho$$

$$\varepsilon = \text{Efficiency} = \frac{1}{(1 + \rho)} \left(\varepsilon_o + \varepsilon_1 \rho\right)$$

It is obvious that the efficiency $\varepsilon > \varepsilon_o$ only if $\varepsilon_1 > \varepsilon_o$. Thus Rankine supplemental heating is justified only if η_R $(T_A - T_o)/T_A$ is significantly larger than the unfired combined-cycle efficiency given previously. Since

$\eta_R > \eta_B$, T_A need not exceed T_i to obtain this desired result but only be in reasonable range of it.

Subappendix AA 12.6.2

TYPICAL REVERSIBILITY INDEX VALUES

Let us consider the differences between cycle types in the matter of reversibility index. The history of heat engine development suggests a fundamental and important difference between phase-change (Rankine) and single-phase (Brayton) cycles in the great difference between their ratios of compression work to net work. The steam cycle with its small feed pump work was reduced to successful practice in the 18th century, but the Brayton cycle, with its large compressor work, had to wait until 20th century technology made efficient compressors and expanders available before it could be reduced to successful practice.

Take a gas turbine cycle—to be specific, the maximum efficiency 1144°K (1600°F), simple cycle of Westinghouse Report 66-1D8-FLINJ-R2 (Reference 12.4). It has a pressure ratio of 20/1 and would use about 4 kg fuel per 100 kg air. The compressor adiabatic efficiency is 0.865 and the turbine 0.90. A 19/1 turbine pressure ratio is assumed to account for pressure loss and use air properties but account for the fuel mass addition. This yields the rough accounting:

Point	h	ϕ	T	Δh	$\Delta\phi$	T_{thermo} $(\Delta h/\Delta s)$
Comp. inlet	124.27	0.59173	520°R			
Comp. outlet	318.56	0.81799	845°R	194.29		
Turbine inlet	521.39	0.94026	2060°R	202.83	0.12227	1658.8
Turbine outlet	258.53	0.76732	1070°R	262.86		
Ambient	124.27	0.59173	520°R	134.26	0.17559	764.6

$$\text{Efficiency} = \frac{262.86 - (194.29/1.04)}{202.83} = 0.3749$$

$$\eta_B = \frac{(0.3749)(1658.8)}{(1658.8 - 764.6)} = 0.6955$$

Of course, losses such as those associated with cooling air, hot part radiation, and so on were not accounted for, and a real cycle η_B will be somewhat lower. Brayton cycle reversibility indices, however, will be found in the range $0.60 < \eta_B < 0.72$.

By contrast, Keystone No. 1 steam unit has a much higher reversibility index. From the heat balance:

Point	h	s	Δh	Δs	Flow
Feed pipe	532.1	0.7232			
Superheater out	1424.0	1.4721	891.9	0.7489	5,784,000
Cold reheat	1254.3	1.4980			
Hot reheat (at P_{cold})	1518.2	1.7160	263.9	0.2180	4,890,553

Condenser T = 563.7°R

Flow Ratio = 0.84553

$$\Delta h/\Delta s = T_T = \frac{[891.9 + (263.9)(0.84553)]}{[0.7489 + (0.2180)(0.84553)]} = 1194.8°\text{R}$$

Net Heat Rate = 7421 Btu/kWh

We assume a combined bearing and alternator loss of 0.012 and auxiliary loads of 0.043 times gross following the Petersen paper at the March 1963 American Power Conference. Then:

$$\text{Gross Heat Rate} = \left(7421\right)\left(\frac{0.957}{0.988}\right) = 7188 \text{ Btu/kWh}$$

$$\text{Shaft Efficiency} = \left(\frac{3413}{7188}\right) = 0.475$$

$$\eta_R = \frac{(0.475)(1194.8)}{(1194.8 - 563.7)} = 0.899$$

A Rankine cycle in which feed is heated in an exhaust cooler rather than in extraction heaters is not burdened with this heat exchange irreversibility and will, in general, have a higher reversibility index. The expected range of values is narrow, perhaps $0.88 < \eta_R < 0.92$. Its variability is dependent on economics rather than on technology limits— primarily with the cost balance between fuel and apparatus.

Note that since the Brayton discussion included no mechanical and electrical loss we have tried to back out these losses in the Rankine discussion. The Keystone heat balance we have does not define the term "Net Work," and we have assumed that it is the alternator terminal work, so that the 0.043 auxiliary fraction is deducted while the 0.012 bearing and alternator fraction is credited. These assumptions are completely ad hoc, so the 0.899 reversibility index calculated is really only a fair approximation, and possibly a little high, for Keystone I. But the conclusion is clear that Rankine cycles are 25 to 35% more reversible than Brayton cycles, and this is a dominating element in the gamesmanship of combined-cycle optimization.

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