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HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

Phase I – Program and System Definition

Topical Report – Low BTU Fuel Combined Cycle Reference Design

GENERATION SYSTEMS DIVISION
WESTINGHOUSE ELECTRIC CORPORATION

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Low-Btu Fuel Combined Cycle Reference Design

ABSTRACT

This report presents a systems design description for a combined cycle based on a High Temperature Turbine Technology, 2600°F combustion turbine operating with a coal-derived low-Btu fuel gas. The overall plant design is based on Westinghouse combined cycle PACE experience and achieves a calculated heat rate of 8,336 Btu/KwHr. at a power output of 925 megawatts.

The power generating system consists of four combustion gas turbines and one 2400 psig/1000°F/1000°F reheat steam turbine. Each gas turbine train includes an unfired heat recovery steam generator, an on-site gasification system and a cold gas cleanup system.

The information presented in this report supplements the Overall Plant Design Description and further defines power generating and gasification components and auxiliaries, balance of plant systems and plant control concepts to the extent necessary to establish the technical feasibility of incorporating this high temperature combined cycle and gasification process into an operating plant system.

A preliminary reliability assessment of the plant in the form of Failure Mode Effects and Criticality Analyses and plant availability is included, together with a plan for evaluating the plant maintainability.

Site and plant layouts establish the size and the physical relationship between major systems.

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INTRODUCTION

In the process of developing a High Temperature Turbine Technology 2600°F combustion turbine, it was recognized that the primary application when utilizing coal-derived fuels would be in the combined cycle. The ECAS studies showed that the method of reaching the lowest cost of electricity was through the utilization of coal in combustion turbine combined cycle systems. In order to assure that the turbine element under development would provide an optimum fit in its ultimate application, a reference design for a combined cycle was made to identify those requirements imposed on the turbine and gasification process design by this particular application.

The Westinghouse PACE combined cycle concept provides the basis for the definition of the power block equipment and the auxiliary equipment packages. The PACE system includes a total power generating package made up of gas turbines, heat recovery steam generators, steam turbines, auxiliary systems and interconnecting equipment and a control system. The gasification and gas cleanup system description was provided by the Foster Wheeler Energy Corporation, based upon the gasifier data furnished by the Institute of Gas Technology.

The development of the Plot Plan and the Plant Island General Arrangement together with the definition of the balance of plant systems was provided by Chas. T. Main, Inc., Engineers. The scope of the balance of plant definition includes the coal handling, crushing and storage system, the startup and standby fuel system, the main and auxiliary cooling water systems, the waste handling-storage and disposal and all civil engineering associated with the site and plant structures.

The reliability assessment of the plant, prepared by the Westinghouse Advanced Energy Systems Division, describes the techniques available for analyzing power plant equipment and systems and provides preliminary analyses of the design.

The major components of all of the plant systems are defined in sufficient detail to establish the technical feasibility of integrating the high temperature, coal gas fired combined cycle into an operable electric generating plant. As a result of the design study, it can be stated that the only major areas requiring technical development are the combustion turbine and the design and integration of the gasification process into the combined cycle.

This Reference Design Report supplements the information presented in Westinghouse Report FE - 2290 - 18 "Overall Plant Design Description - Low-Btu Combined Cycle Electric Power Plant (Reference 2)". This report, therefore, reestablishes the basic design concepts and contains those items required to complete the plant reference design which were not identified in the Request For Quotation as being part of the Overall Plant Design Description, Reference RFP E(49-18)-1806, Appendix 4.

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Low-Btu Fuel Combined Cycle Reference Design

CONCLUSIONS AND RECOMMENDATIONS

The Reference Design is a combined cycle power generating plant, utilizing four (4) combustion turbine boiler sets to achieve a total capability of approximately 925 MWs with a heat rate of 8,336 Btu/KwHr. The plant includes an IGT-U-GAS coal gasification system with Selexol Sulfur removal. In preparing the total design definition of the plant, the major areas requiring technology that does not exist today are:

(a) the coal gasification system producing raw coal gas;

(b) the 2600^{o}F combustion gas turbine;

(c) the technology related to the cleanliness of the fuel gas required for acceptable turbine hot part life.

Other than the three areas cited above, all of the technology required to construct a power plant of the type described exists today, either in the power generating industry or the chemical process industry. The principle risk would be in combining the various systems and pieces of equipment without allowing sufficient time for proper integration and shakedown during the phases of design and initial operation. Because of the complexity of the plant, it is expected that the system would be applied principally for base load power generation and would have a limited capability to take load swings.

In investigating the Reliability potential for the overall system, it appears that the use of four (4) combustion turbine power trains in the plant would result in very high availability with regard to achieving a significant fraction of the total, rated capacity. This characteristic of multi-unit combustion turbine combined cycles has been borne out by current combined cycle power plant experience.

In the reference power plant, the raw fuel gas is cleaned through the use of venturi-scrubbers which result in the requirement to remove most of the sensible heat from the fuel gas, dropping its temperature from 1900^{o}F to less than 100^{o}F. Studies indicated that a significant improvement in plant performance can be achieved if the gas can be cleaned hot. This hot-gas cleanup utilizing granular bed filters and iron oxide sulfur removal offers the potential of improving the heat rate to a level of 7,740 Btu's per KwHr. In hot-gas cleanup (since significantly less steam is produced in the gasification system) there is also the possibility that a practical means of converting liquid fuel fired combined cycle plants to coal gasification systems may be achieved. For these reasons, hot-gas cleanup merits additional investigation.

Other areas where additional investigation would be appropriate include cost evaluation, controllability and gasifier effects. The cycle optimization studies were all related to obtaining the best possible heat rate with little attention to the ultimate cost of electricity. Final cycle selection should be based on trade-off studies evaluating the contribution to heat rate improvement of each cycle modification versus the cost of the associated equipment and its effect on plant availability. When coal gasification is used in combination with a combined cycle power plant, the control parameters become considerably more complex. Since the availability at any point in time of fuel supply depends on the operating characteristics of the gasification plant, investigations should be conducted that relate the dynamic characteristics of an electric utility to the total power generating system. The plant, as presented in this report is based on utilization of the IGT U-GAS Gasification System and is further restricted by the design parameters which were selected. Additional studies are appropriate to determine the effects of other gasifier types on the design requirements of the HTTT engine. In addition, some of the design selections for the gasifier used, such as the source and conditions of gasifier steam should be investigated, since this could effect not only overall cycle performance but also the fuel burning characteristics and heat value which would relate to engine design.

During the initial cycle study phase, calculations were performed using a current combustion turbine. These calculations resulted in performance levels competitive with present day steam fossil plants. It would therefore appear most beneficial if, in parallel with the development of the high temperature turbine, a demonstration plant utilizing current technology was undertaken to bring the total system to a state of utility acceptance concurrent with the commercial availability of the high temperature turbine.

Specific recommendations are:

(1) Continue work to conclusively establish the feasibility of hot-gas cleanup for high temperature combustion turbine systems.

(2) Perform further studies on the controllability of coal gasification combined cycles when applied in base-load to a utility system.

(3) Perform additional cycle analysis to insure the compatibility of the combustion turbine with all of the gasification systems under development.

(4) Perform the plant evaluation studies necessary to insure that the cycle selected provides the lowest cost of electricity.

(5) Proceed at the earliest possible time with a complete power generating plant to provide the real operational hardware experience necessary for a utility acceptance.

SECTION 1
PLANT DESCRIPTION

1.1 CYCLE CONFIGURATION SELECTION

1.1.1 Cycle Component Evaluation

In order to arrive at the best configuration for the coal-derived gaseous fuel-fired combined cycle power plant, a preliminary investigation utilizing existing gas turbine performance parameters from the Westinghouse W501D gas turbine was performed. The specific intent of the investigation was to determine on a preliminary basis the relative contribution of various components in the cycle so that the final plant configuration and arrangement could be concluded expeditiously when the high temperature turbine performance parameters became available. The fuel producing process and clean-up equipment used in the preliminary studies is the IGT U-Gas system in series with a gas cooler, aqueous scrubber and Sulfinol tower. The clean-up of the gas involves particle removal by separators and scrubbers, ammonia removal in the aqueous scrubber and H_2S and COS removal in the Sulfinol tower.

The studies performed under the ECAS contract related to a high temperature gas turbine fired on a liquid fuel with both non-reheat and reheat-type steam turbines used in the combined cycle mode. While these data provide some insight on the type and configuration of the cycle to be used in the coal-derived low-Btu gaseous fuel combined cycle plant, the studies cannot be adapted entirely due to the unique characteristics of the gasification process.

The gasifier used in the production of the low-Btu gas provides a sizable quantity of heat which is used to generate steam. The process steam, along with the steam produced in the heat recovery steam generator (HRSG) which utilizes gas turbine exhaust gas heat, imposes a higher feedwater heating and economizer duty than a conventional combined cycle power plant. Therefore, additional studies were performed to determine what effect the increased feedwater heating duty imposes on the overall cycle; and what influence specific components in the cycle have on overall performance. The attached Table 1.1-1 lists the performance changes as various additions, alterations and deletions were made to the combined cycle. The tabulation is based on one W501D combustion turbine and one steam turbine.

Figures No. 1 through 11, referenced in the table, identify the affected area of the cycle where the alterations are being made, by cross-hatching the applicable lines and equipment items.

TABLE 1.1-1
COAL GASIFICATION COMBINED CYCLE STUDY
(BASED ON ONE W501 D GAS TURBINE AND ONE STEAM TURBINE)

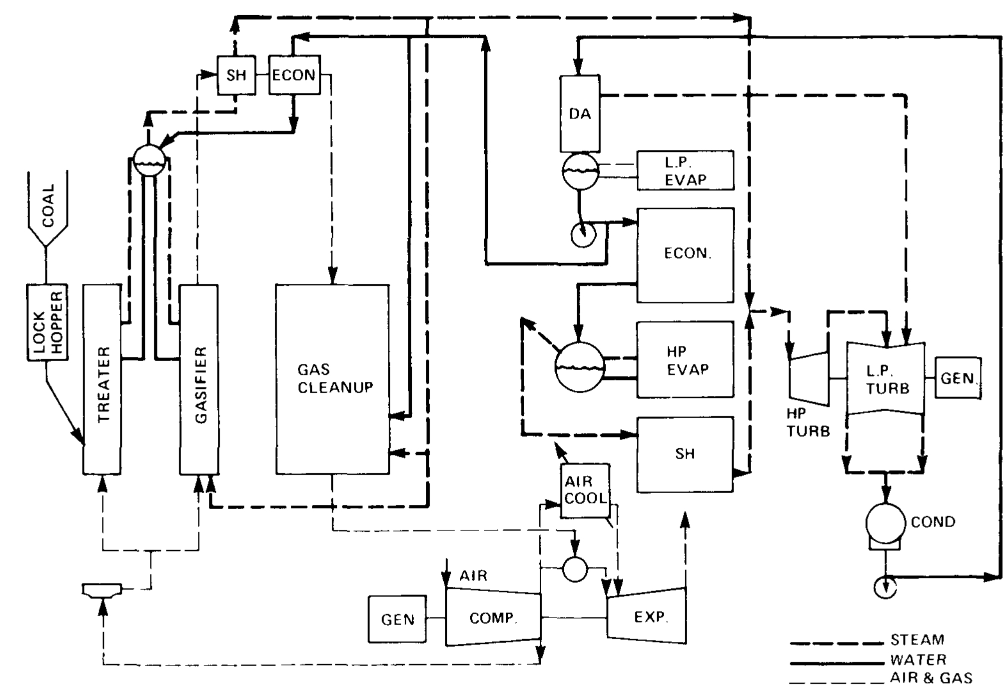
Item No.	Identification	Figure No.	GT KW	ST KW	Net KW	Net Hr.	Improvement		KW Change	
							BTU	%	KW	%
1	PACE Type Arrangement - Baseline	1	90,240	71,785	151,310	10,026	-	-	-	-
2	Add Fuel Heater to 1	2	89,773	66,947	146,650	9,719	307	3.06	-4660	-3.0
3	Add GT Air Cooler/Heat Exch.	3	89,773	67,399	147,102	9,689	30	0.31	+ 452	+ .31
4	Add IP Evaporator	4	89,773	71,371	151,074	9,435	254	2.62	+3972	+2.70
5	Extract 140 PSI Steam	5	89,773	71,867	151,570	9,404	31	0.33	+ 496	+0.33
6	Add Main Steam Reheat	6	89,773	78,871	158,574	8,988	416	4.42	+7004	+4.62
7	Add 1 Closed FW Heater	7	89,773	79,900	159,603	8,930	58	0.65	+1029	+0.65
8	Add 2nd Closed FW Heater	8	89,773	80,300	160,003	8,908	22	0.25	+ 400	+0.25
9	Rearrange Fuel Heater and Air Cooler	9	89,773	80,300	160,003	8,908	0	0.00	0	0.00
10	Redistribute Usage of Gasifier Heat (All IP Evap. in Gasif.)	10	89,773	80,444	160,147	8,900	8	0.09	+ 144	+0.09
11	Proposed W501D Cycle (10 less 3, 5,8)	11	89,773	78,649	158,352	9,000	-100	-1.12	-1795	-1.12

Baseline performance was established on the basis of a "PACE" type plant wherein fuel at $120^{o}F$ is introduced into the gas turbine. The HRSG is unfired, containing a high-pressure economizer, evaporator and superheater, along with a low-pressure evaporator used for feedwater heating and deaeration.

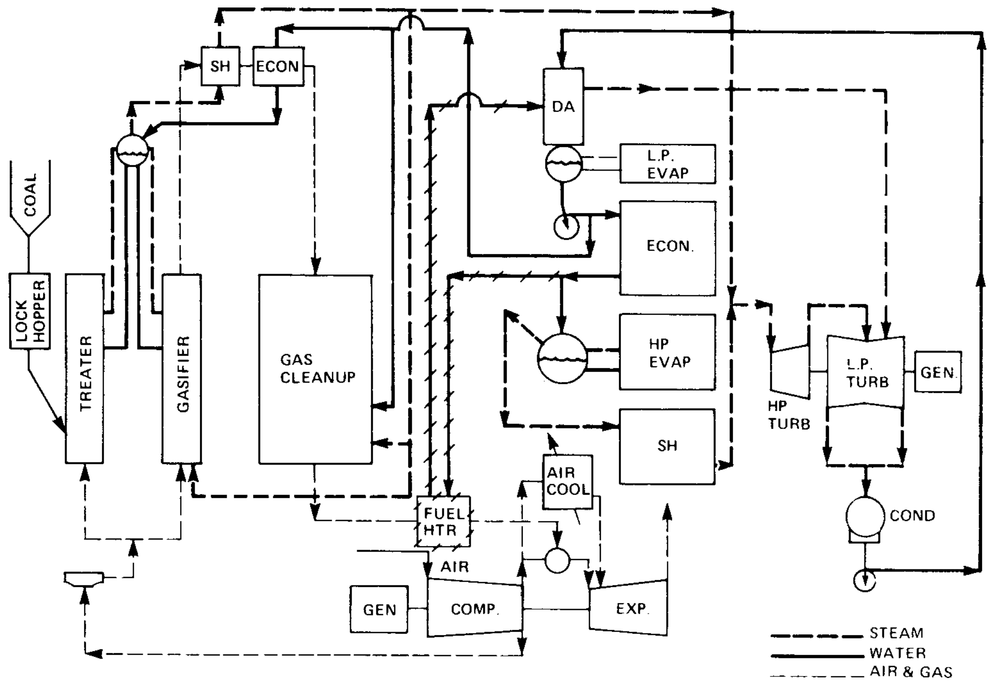
The steam turbine is a single case, non-reheat turbine similar to that used in the "PACE" applications with steam conditions of 1250 psig-$950^{o}F$-2.5 In. Hg absolute. The performance is shown in Item One of Table 1.1-1 (see Figure 1.1-1).

By heating the fuel gas prior to combustion, a sizeable improvement in heat rate at the expense of some loss of output is attained. The fuel heating is accomplished by utilizing economizer water, which returns to the deaerator. Item Two of Table 1.1-1 shows the performance based on heating the fuel to $580^{o}F$ prior to combustion (see Figure 1.1-2).

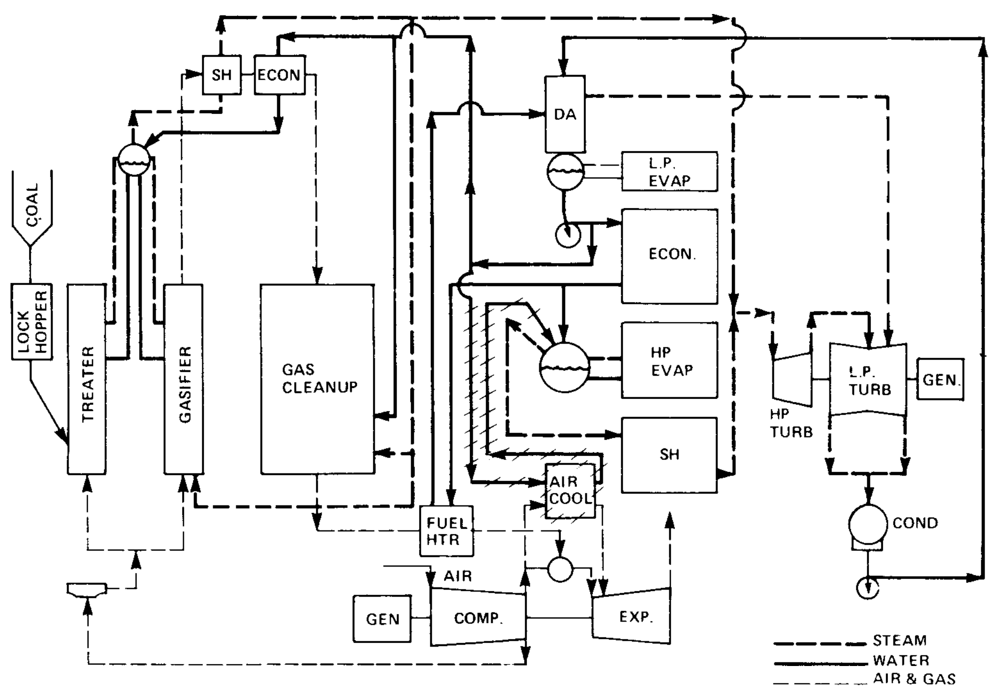
In order to cool the critical areas in the gas turbine hot section, it is necessary to pass some of the turbine cooling air through a cooler before it is utilized. In an ordinary simple cycle installation, the heat extracted from the cooling air is rejected to the atmosphere. In the combined cycle, this heat can be used in the feedwater heating portion of the cycle. This reduces the economizer duty somewhat, which in turn allows the low-pressure evaporator to make a larger contribution to feedwater heating. The ultimate benefit is a reduction in extraction steam, resulting in a slight increase in steam turbine output. The heat rate improved 30 Btu/KwH and output increased 452 KW, as shown in Item Three of Table 1.1-1 (see Figure 1.1-3).



COAL-GAS COMBINED CYCLE – BASELINE
Figure 1.1-1



COAL-GAS COMBINED CYCLE – ADDED FUEL HEATER
Figure 1.1-2



COAL-GAS COMBINED CYCLE – ADDED AIR COOLER/HEAT EXCHANGER
Figure 1.1-3

The chief drawback of the three (3) systems discussed so far is the poor utilization of energy in the gasification system. The gas cooler, gasifier and treater are producing steam that is used in the gasification process, gas clean-up processes, and the steam turbine. All of the steam is produced at steam conditions required by the steam turbine. This necessitates throttling a portion of the steam that is utilized in the gasifier-cleanup apparatus.

The introduction of an intermediate pressure evaporator in the HRSG to provide some of the gasifier cleanup steam requirement resulted in another sizable improvement in the plant efficiency. The 70 psi steam needed in the cleanup process could now be supplied without throttling. (The 140 psi gas-cleanup steam requirement, and the 300 psi gasifier steam requirement are still supplied by throttling.)

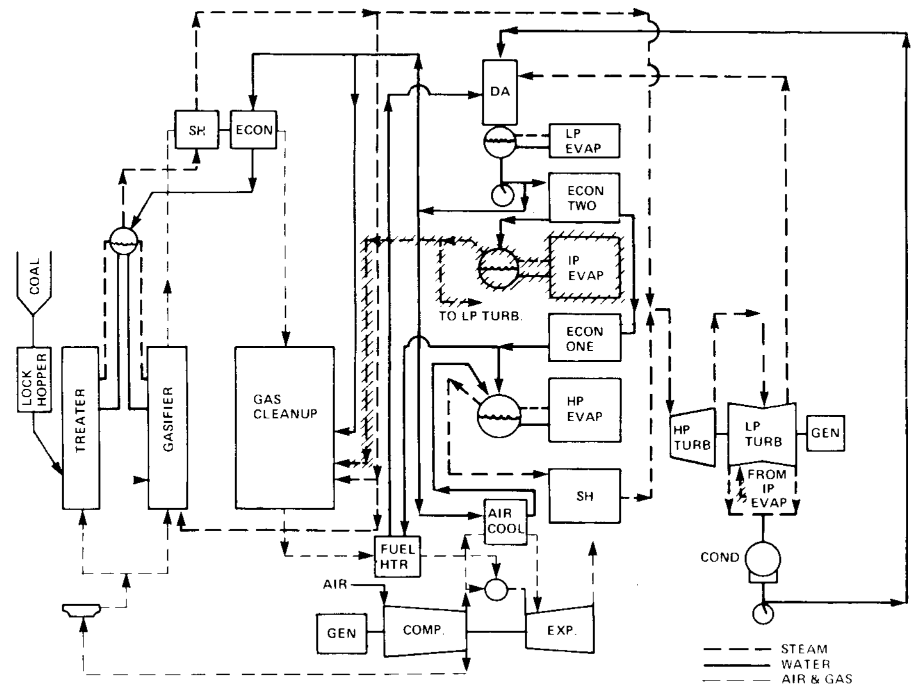
Item Four of Table 1.1-1 lists the performance and the improvement over the previous configuration. It is at this point that the plant output is at the level of the initial arrangement, but the plant efficiency is considerably better (see Figure 1.1-4). Item Five shows another small gain in performance by using extraction steam from the steam turbine to provide 140 psi steam to the gasifier cleanup system rather than throttling high-pressure steam produced by the gasifier (see Figure 1.1-5).

The most significant contribution to performance improvement is accomplished by adding main steam reheat to the cycle. After the combined steam flows from the gasifier system and HRSG are expanded through the high-pressure turbine, the total flow is sent to the reheater in the HRSG where the steam is heated to approximately initial superheat temperature. A portion of the reheated steam is sent to the gasifier with the balance returning to the steam turbine.

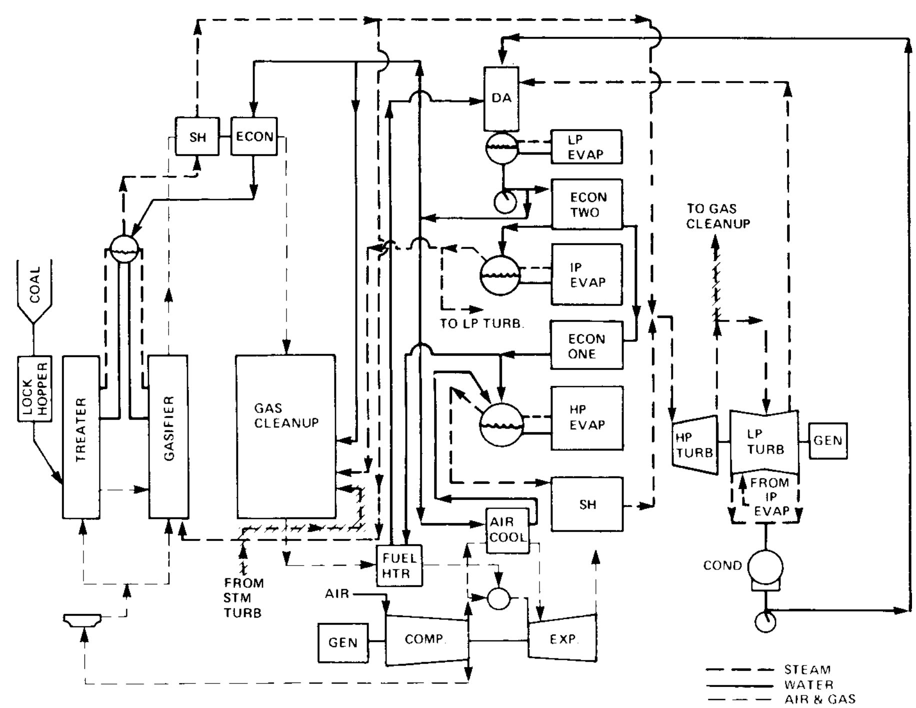
The hot reheat provides process steam to the gasifier at correct steam conditions rather than throttling high-pressure steam which had been done previously. The steam conditions became 1450 psig-966^{o}F-961^{o}F-2.5 In. HgA. These new reheat steam conditions improved the efficiency of the low-pressure expansion in the turbine. The combination of eliminating the throttling process and improving the steam turbine performance resulted in a 416 Btu/KwH heat rate improvement and 7004 KW additional output over the previous non-reheat cycle. Item Six of Table 1.1-1 lists the performance: 158,574 Net KW at 8,988 Btu/KwH (see Figure 1.1-6).

At this point, attention was focused on feedwater heating. The addition of a low-pressure closed heater in the feedwater heating circuit reduced the amount of extraction required at deaerator pressure. The end result is an additional 1,029 KW of output with a corresponding 59 Btu/KwH heat rate improvement. By adding a second closed heater prior to deaeration, another 22 Btu/KwH heat rate improvement and an additional 400 KW output is achieved. See Items Seven and Eight of Table 1.1-1 (see Figures 1.1-7 and 1.1-8).

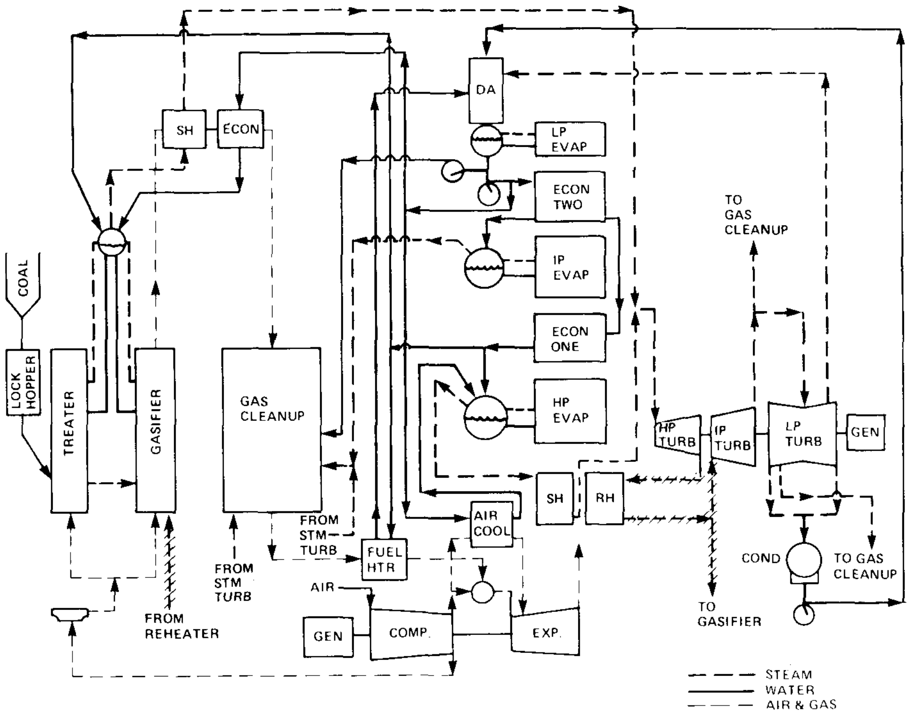
In order to simplify the level controls in the high pressure drum, the gas turbine air cooler heat rejection was switched from heating a separate stream of feedwater to aiding in the heating of the fuel to the gas turbine combustors. There was no change in the cycle performance as comparison of Items Eight and Nine of Table 1.1-1 shows (see Figure 1.1-9).



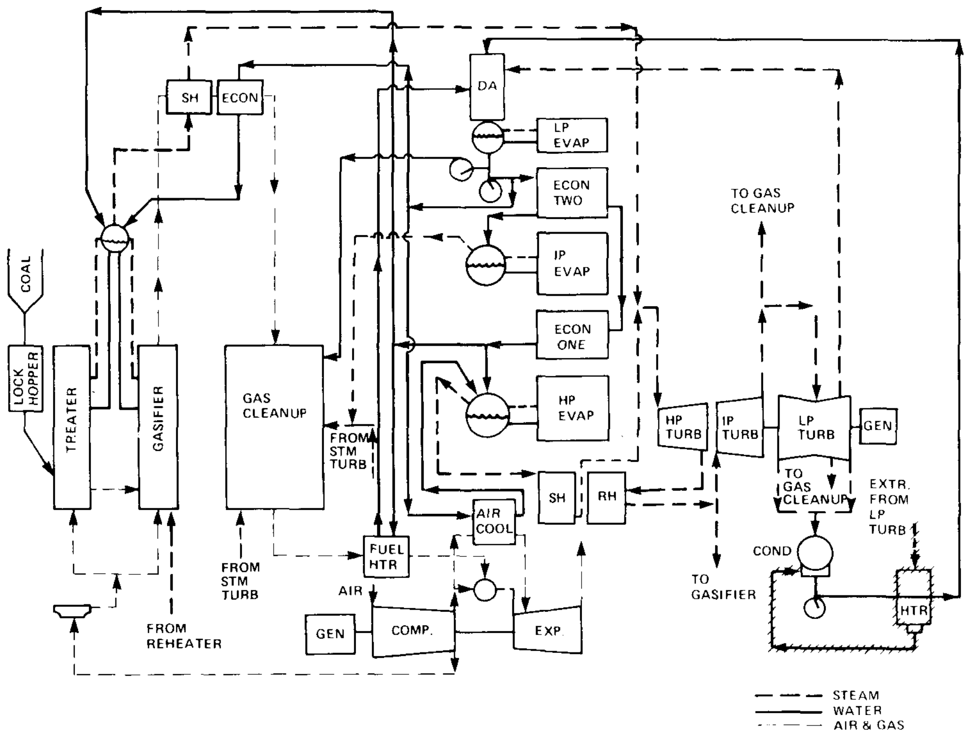
COAL-GAS COMBINED CYCLE – ADDED IP EVAPORATOR
Figure 1.1-4



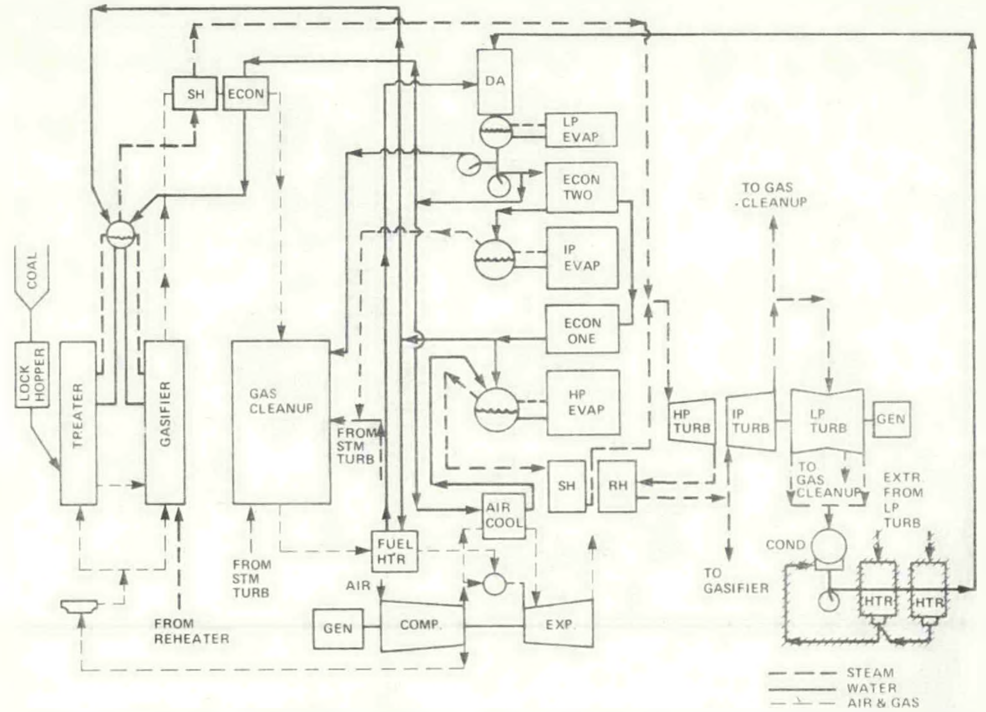
COAL-GAS COMBINED CYCLE – EXTRACT 140 PSI STEAM
Figure 1.1-5



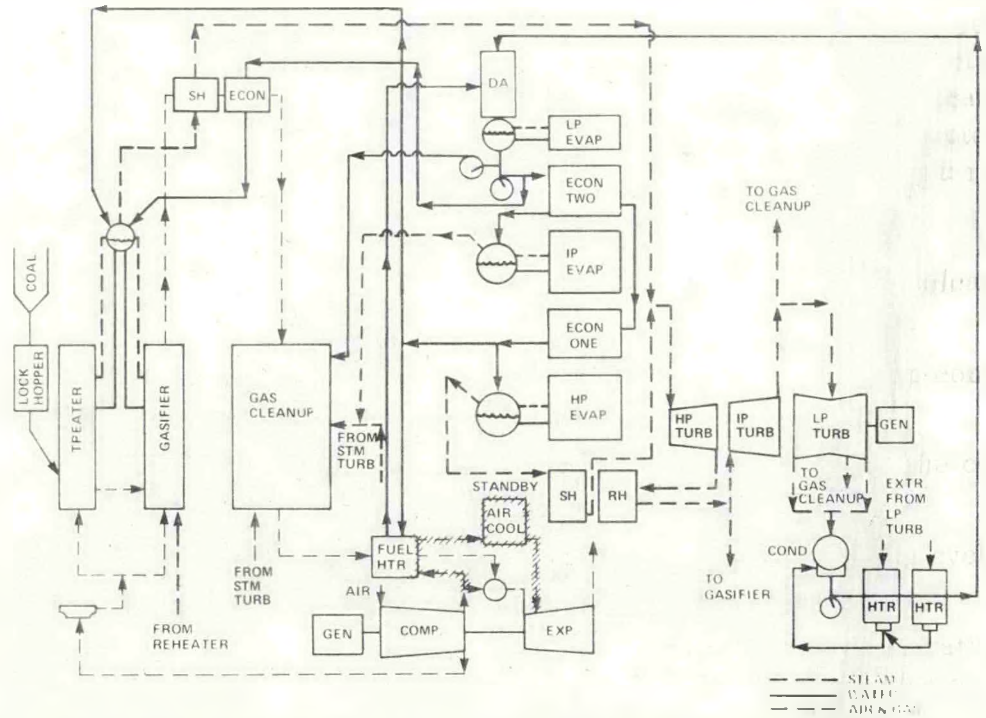
COAL-GAS COMBINED CYCLE – ADD MAIN STEAM REHEAT
Figure 1.1-6



COAL-GAS COMBINED CYCLE – ADD 1 CLOSED FW HEATER
Figure 1.1-7



COAL-GAS COMBINED CYCLE — ADD SECOND CLOSED FW HEATER
Figure 1.1-8



COAL-GAS COMBINED CYCLE — REARRANGE FUEL HEATER AND AIR COOLER
Figure 1.1-9

All of the cycle configurations discussed so far involved a gas cooler in the gasifier system, which heated feedwater and provided superheat for the steam produced. To further simplify the system, the gas cooler function was changed so that it produced all of the 70 psi process steam and provided superheat for the steam produced in the gasifier system. Therefore, all of the feedwater is heated at the HRSG. This altered arrangement produced essentially the same performance as the previous one as the comparison of Items Nine and Ten in Table 1.1-1 shows. (see Figure 1.1-10)

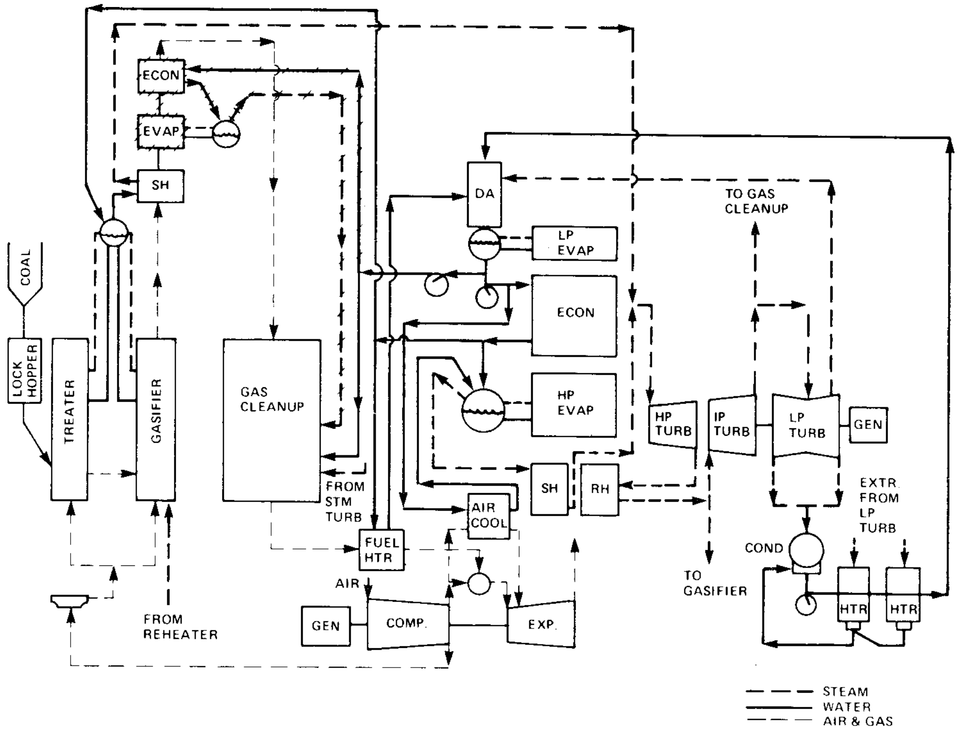
After analysis and inspection of the various arrangements and components, the proposed configuration utilizing the W501D gas turbine was selected. Item Eleven of Table 1.1-1 is essentially the arrangement as described in Item Ten minus three (3) of the lesser contributors to efficiency; namely, the air cooler heat, the 140 psi extraction, and the second closed feedwater heater. Table 1.1-1 shows the cumulative effect of the three (3) items on heat rate to be 83 Btu/KwH. Actual calculation of the cycle shows the effect to be 100 Btu/KwH. (see Figure 1.1-11)

The slightly larger effect can be attributed mainly to the increased economizer duty which occurred when the air cooler heat was not utilized and the gas cooler low-level energy was altered to produce low-pressure saturated steam for gas cleanup. Both items resulted in higher feedwater flows through the HRSG economizer. Since the stack temperature is kept constant at 280°F in this study, the increased economizer duty necessitated an increased pinch-point which in turn, reduced the amount of high-pressure steam generated. The cumulative effect penalized the cycle performance slightly more than the simple summation of Items Three, Five and Eight of Table 1.1-1.

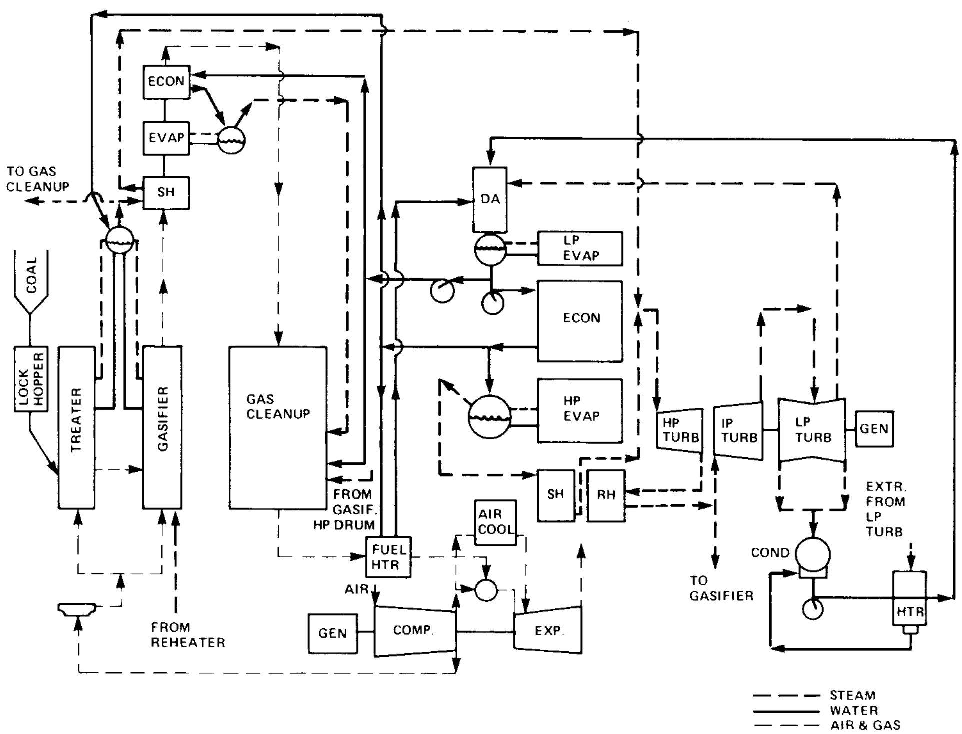
1.1.2 Cycle Screening Study

Using preliminary performance data on the high-temperature, air-cooled, gaseous fuel-fired turbine, a screening study to obtain initial cycle data was made. Gasifier data were changed proportionately with the change in required flow relative to the W501D cycle studies.

The initial calculation utilized the plant arrangement similar to Item Eleven of Table 1.1-1. The intent was to calculate cycle performance using a plant configuration similar to Item Eleven; that is, the gas cooler would be utilized to superheat steam produced in the gasifier/treater and to produce the 70 psi saturated steam for gas cleanup; all main feedwater would be heated in the HRSG economizer; and, one closed heater along with one deaerating heater would aid in the feedwater heating cycle. The gas turbine cooling air cooler heat rejection was utilized to aid in fuel heating, however. In addition, the gland condenser and ejector heat rejection were utilized to heat condensate which was not done previously. The HRSG stack temperature remained at 280°F. Two quantities emerged from the calculations that affected the overall efficiency of the cycle. First, since the gas turbine exhaust temperature is about 200°F



COAL-GAS COMBINED CYCLE – REDISTRIBUTE GASIFIER HEAT
Figure 1.1-10



COAL-GAS COMBINED CYCLE – PROPOSED W501D CYCLE
Figure 1.1-11

higher than the previous W501D, and since the steam conditions in the HRSG evaporator were kept identical to the previous work, more steam was generated. Secondly, since fuel flow increased, gasifier steam production also increased.

The increased steam production imposed a corresponding duty increase on the HRSG economizer. Since the stack temperature remained at 280°F, the evaporator pinch-point had to be increased to reduce steam flow and satisfy the economizer duty. The end result is less than optimum steam generation in the HRSG, which in turn, reduces steam turbine output. Another slight detriment (which also occurred on the W501D cycle in this plant configuration) was an elevation in gas cooler exit temperature. Optimum exit temperature is 300°F. In this case, the gas cooler exit gas temperature is 317°F. The performance for this configuration is listed as Item One of Table 1.1-2 (see Figure 1.1-12).

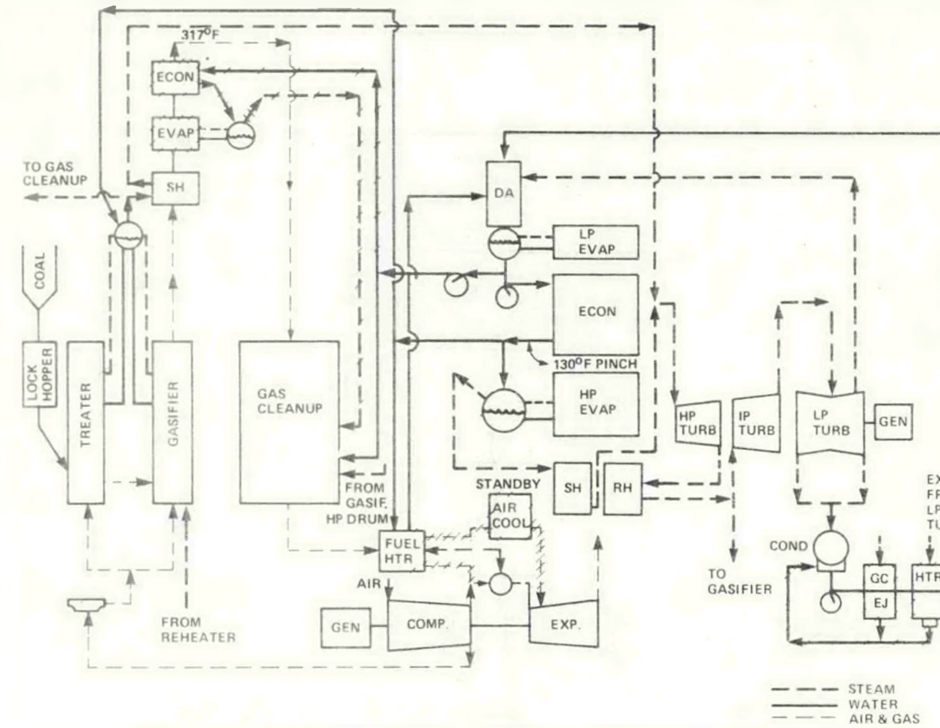
The gas cooler exit temperature was reduced to 300°F by circulating additional feed-water through the gas cooler low-temperature economizer. The additional feedwater was then brought to the HRSG and mixed with the remaining economizer water. This reduced the economizer duty somewhat which reduced the evaporator pinch-point accordingly, thus producing slightly more steam. The pinch-point reduction amounted to 3°F and the resulting performance is listed as Item Two of Table 1.1-2 (see Figure 1.1-13).

The second attempt at relieving the economizer duty to improve performance gained 30 Btu/KwH in plant heat rate over the original arrangement. In this case, the feed-water stream was split at boiler feed-pump discharge. A portion was sent to the HRSG economizer and the remainder was heated in a series of three (3) closed heaters; the last of which was supplied with cold reheat steam. The two streams were then rejoined for final heating in the second HRSG economizer. The gas cooler exit temperature is the same as originally, 317°F. See Item Three of Table 1.1-2 (see Figure 1.1-14).

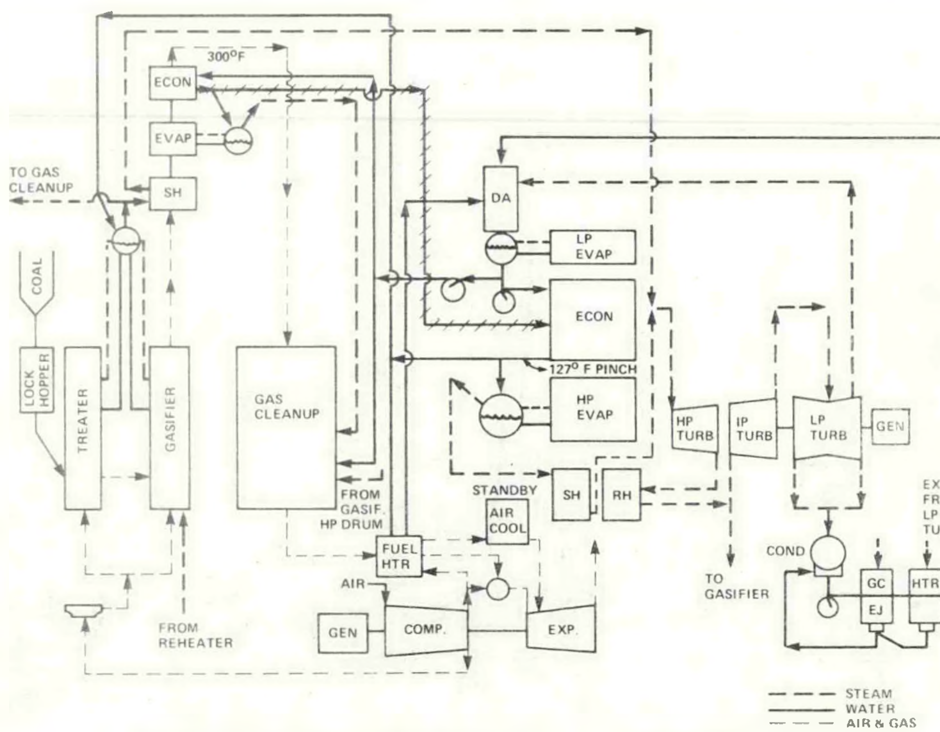
Since the HRSG pinch-point was still rather high (106°F), a calculation was performed utilizing a cycle configuration similar to Item Seven of Table 1.1-1. This configuration reverts the energy use in the gas cooler to high-pressure economizer and superheater rather than producing 70 psi process steam and superheated high-pressure steam. In this arrangement, the previous problem of excessive HRSG economizer duty can be relieved somewhat, since the feedwater stream is split prior to the HRSG economizer. The steam conditions for the steam turbine remained at 1450 psig-1000°F-1000°F-2.5 In. HgA. The performance for this arrangement is 219,502 KW and 8,268 Btu/KwH heat rate. The gas cooler exit temperature and HRSG pinch-point are 300°F and 66°F, respectively. See Item Four of Table 1.1-2 (see Figure 1.1-15). The HRSG pinch-point was improved dramatically and the overall cycle performance improved over one (1) percent, when compared to Item Three of Table 1.1-2. The evaporator pinch-point, that is, the difference between the gas temperature leaving the HRSG evaporator

TABLE 1.1-2
COAL GASIFICATION COMBINED CYCLE STUDY BASED ON PRELIMINARY HIGH TEMPERATURE TURBINE DATA: ONE GAS TURBINE AND ONE STEAM TURBINE

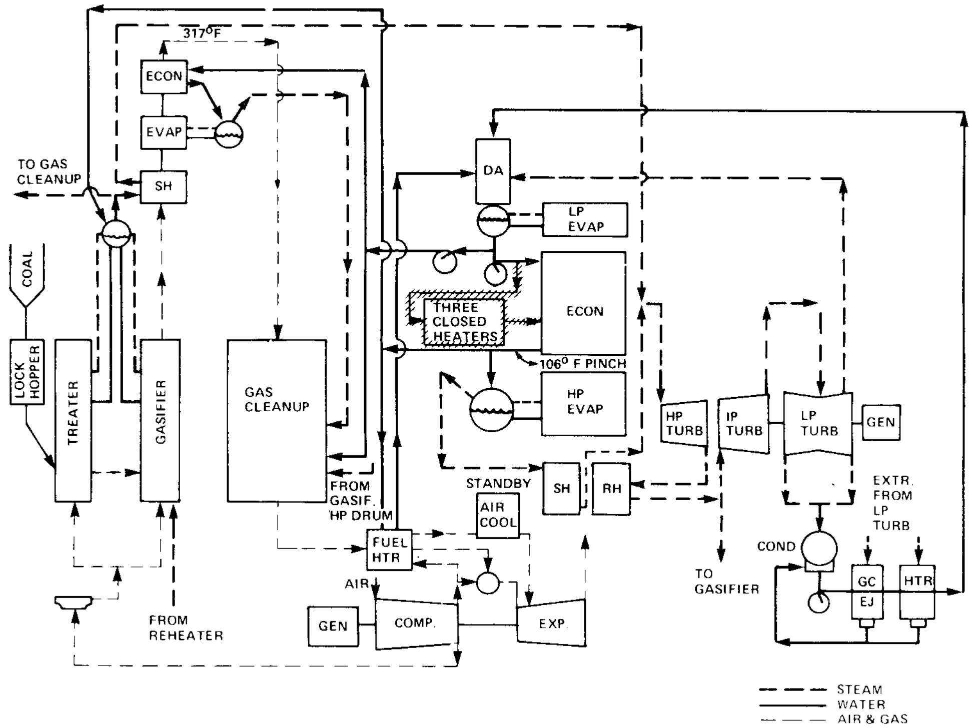
Item	Description	GT KW	ST KW	Net KW	Net Heat Rate	Improvement		Change	
						BTU	%	KW	%
1.	1P Evap. in gas cooler, one closed heater HRSG Pinch = 130F, gas cooler exh. temp. = 317F; 1450 PSIG-1000F-1000F-2.5 In. HgA Steam. Ref. Fig. 12	125,333	103,966	215,722	8,412	-	-	-	-
2.	Same as above, except heat additional feedwater in gas cooler. HRSG Pinch=127F, Gas Cooler Exhaust Temp.=300F. Ref. Fig. 13.	125,333	104,409	216,140	8,396	16	0.19	418	0.19
3.	Same as Item 1, except split feedwater stream to reduce economizer duty. HRSG Pinch=106F, gas cooler exhaust temp.=317F. Three closed heaters in split stream. Ref. Fig. 14.	125,333	104,811	216,517	8,382	14	0.17	377	0.17
4.	Eliminate IP evaporator in gas cooler. Use gas cooler for economizer and superheater. Extract from steam turbine for gasifier & cleanup requirements. Pinch=66F. Gas cooler exh. temp. = 300F. Steam conditions 1450 PSIG-1000F-1000F-2.5 In. HgA. Ref. Fig. 15.	125,333	107,984	219,502	8,268	114	1.36	2,985	1.38
5.	Similar to Item 2. Raise steam conditions to 2400 PSIG-1000F-1000F-2.5 In. HgA. HRSG Pinch=103F, Gas cooler exit temp. = 300F. Gasifier/Treater Pinch-Points improved over items 1, 2, 3, 4. Ref. Fig. 16.	125,333	109,032	220,490	8,230	38	.46	988	.45
6.	Same as 4, except steam conditions are 2400 PSIG-1000F-1000F-2.5 In. HgA. HRSG Pinch=51F. Gasifier/Treater Pinch-Points improved over item 4. Ref. Fig. 17.	125,333	113,164	224,376	8,088	142	1.73	3,886	1.76



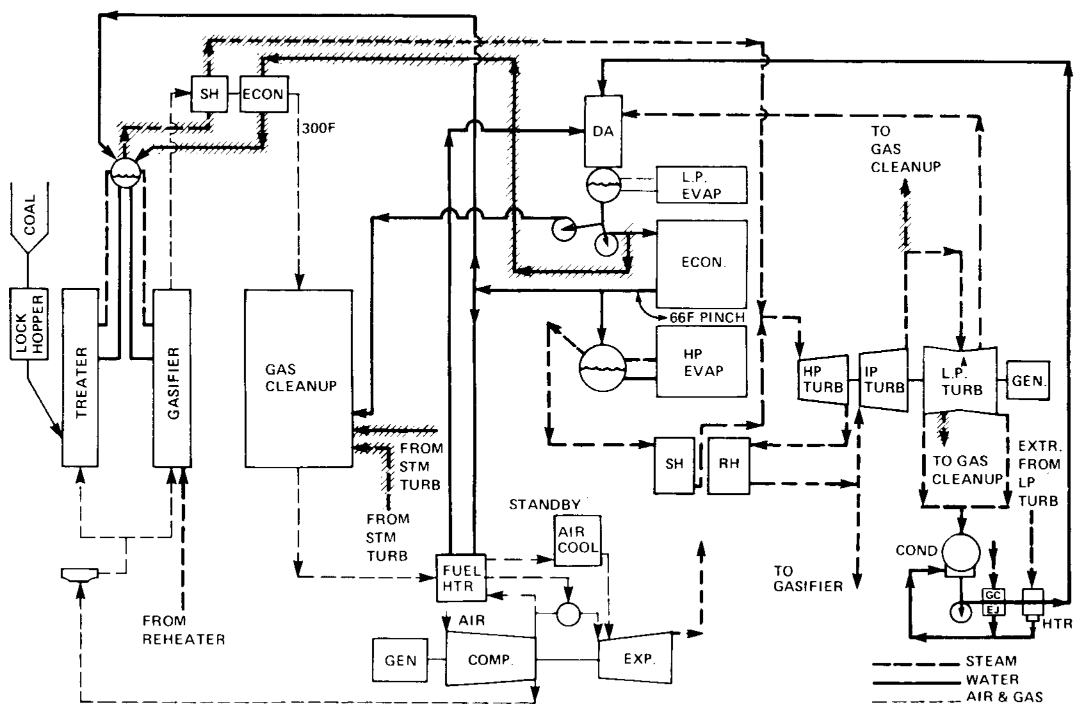
COAL-GAS COMBINED CYCLE — HRSG PINCH 130°F
Figure 1.1-12



COAL-GAS COMBINED CYCLE — HRSG PINCH 127°F
Figure 1.1-13



COAL-GAS COMBINED CYCLE – HRSG PINCH 106°F
Figure 1.1-14

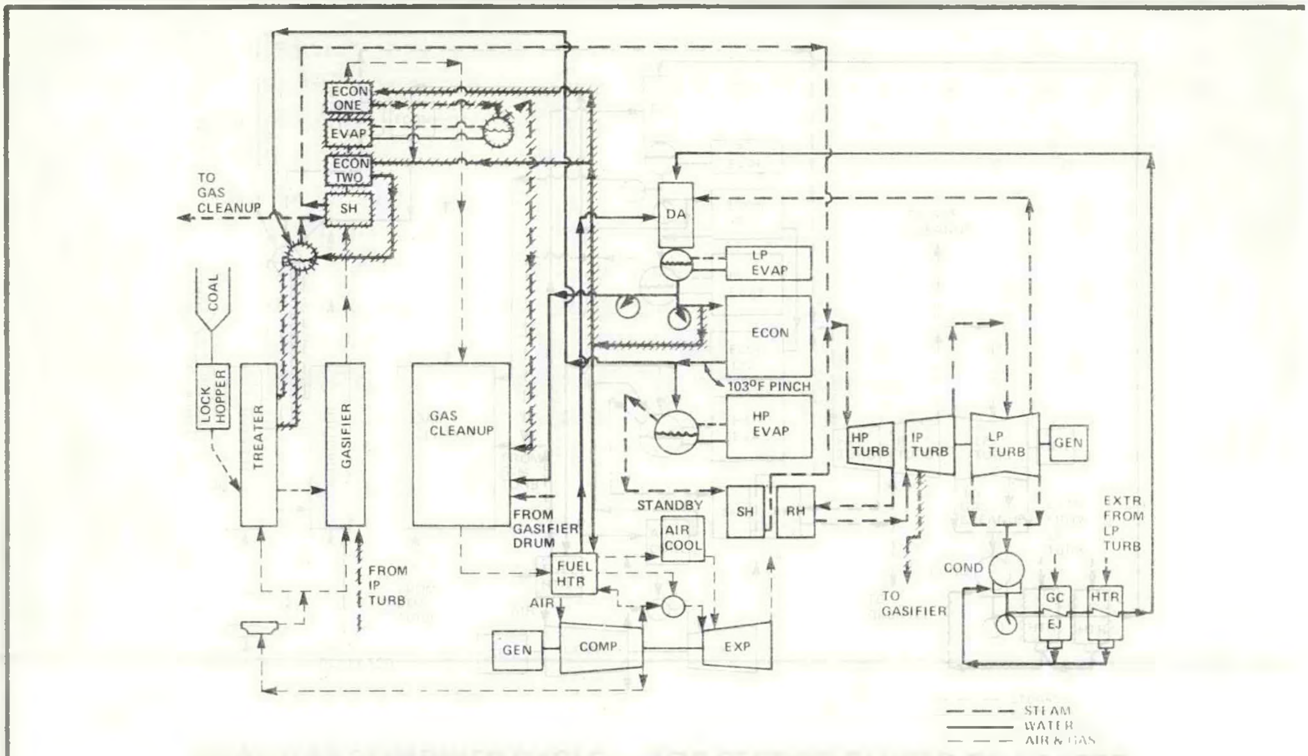


COAL-GAS COMBINED CYCLE – HRSG PINCH 66°F
Figure 1.1-15

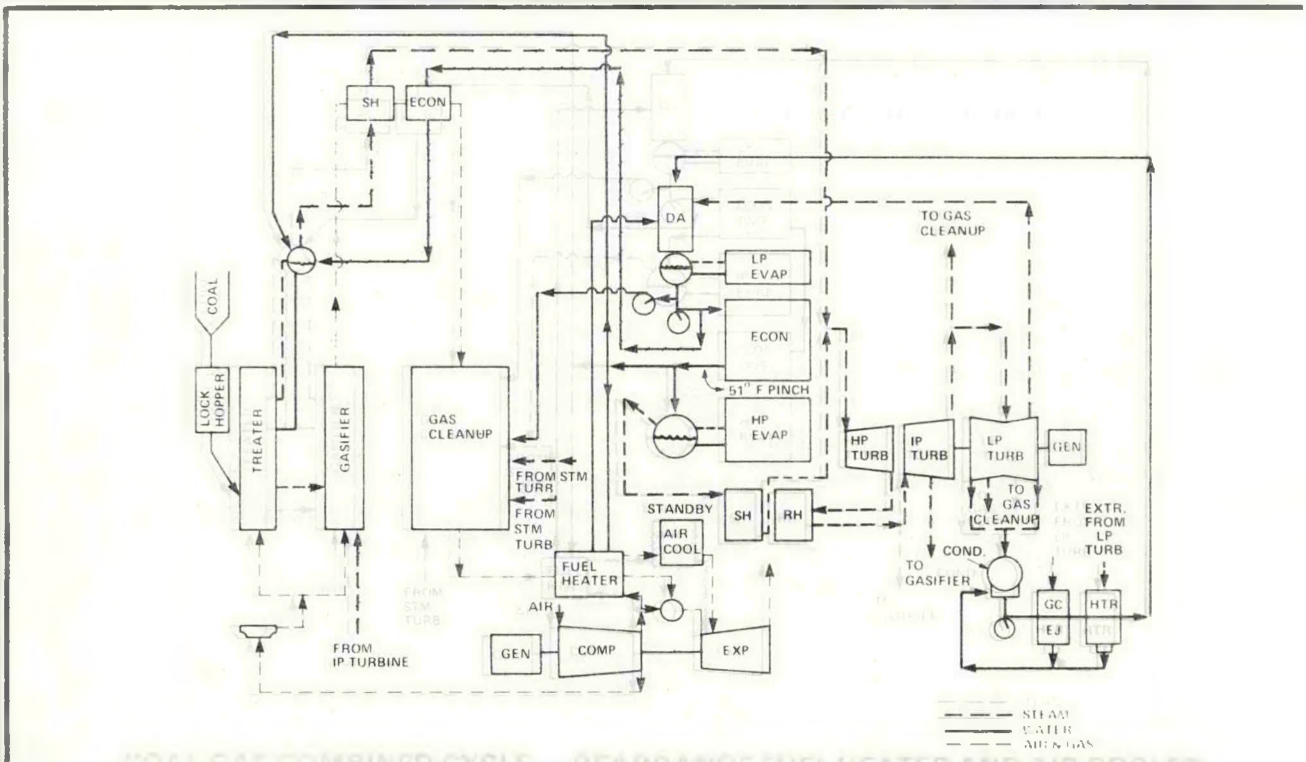
and the water temperature entering the evaporator, was reduced from 106°F to 66°F. In all four (4) instances, the drum pressure was 1,625 psia.

In an effort to improve cycle efficiency further, the cycle arrangement was altered in two ways. First, the gas cooler heat utilization reverted to high-pressure steam superheating and low-pressure steam evaporating, as was done in Item Three, Table 1.1-2; and, secondiy, the main drum pressure was increased to 2,683 psia. This, in effect, changed the steam turbine steam conditions from 1450 psig-1000°F-1000°F-2.5 In. HgA to 2400 psig-1000°F-1000°F-2.5 In. HgA. The intent was to increase cycle efficiency by further reducing the HRSG pinch-point. Item Five of Table 1.1-2 shows the performance based on these changes: 220,490 KW and 8,230 Btu/KwH. This is an improvement of 38 Btu/KwH over Item Four of Table 1.1-2. The gas cooler exit temperature remained at 300°F by judicious energy management in the gas cooler economizer and low-pressure evaporator. The HRSG pinch-point for this scheme is 103°F. Although the HRSG pinch-point became more critical, the higher pressure steam caused the pinch-point in the gasifier/treater to improve. In the previous schemes, saturated steam was produced from heat generated in both the treater and gasifier. The evaporator pinch-point in the treater was 183°F and the evaporator pinch-point in the gasifier was about 700°F. When the steam conditions were changed, the required heat of evaporation was diminished, while the required heat to bring the saturated steam to superheat temperature was increased. By producing all of the saturated steam from the treater heat source and producing the superheated state utilizing the gasifier heat, the pinch-point became 121°F for the gasifier/treater produced steam. The overall effect is a small improvement, as shown in Item Five of Table 1.1-2 (see Figure 1.1-16).

The results of the calculations of Item Five of Table 1.1-2 reiterated the problem of excessive HRSG pinch-point when the gas cooler low-level heat was used to make gas cleanup process steam. It became apparent that for best efficiency overall, the gas cooler low-level heat should be used to heat feedwater going to the gasifier/treater steam drum. This action makes the largest contribution toward reducing the excessive HRSG economizer duty. The cycle performance was recalculated on the above basis, while maintaining the 2400 psig steam conditions. Energy utilization around the gas cooler improved as it did in Item Three, Table 1.1-2, and the reduced HRSG economizer duty reduced the HRSG pinch-point to 51°F. The resulting KW and heat rate are 224,376 and 8,088 respectively (see Item Six of Table 1.1-2). In this configuration as in the previous case, the required gasifier process steam is extracted from the intermediate pressure steam turbine. The 140 psi and 70 psi steam needed for gas cleanup is extracted from the steam turbine as well (see Figure 1.1-17). Other arrangements were studied wherein the feedwater was split in various ways in efforts to reduce the HRSG economizer duty. None proved fruitful, however, and the arrangement and performance described in Item Six and Figure 1.1-17 became the prime choice based on the preliminary high-temperature turbine data.



COAL-GAS COMBINED CYCLE — HRSG PINCH 103°F
Figure 1.1-16



COAL-GAS COMBINED CYCLE — HRSG PINCH 51°F
Figure 1.1-17

The overall thrust of this cycle configuration study was to enumerate the contribution to efficiency that the various components in the cycle make. To recapitulate briefly, the effect of fuel temperature, extraction, feedwater heating, reheating, multi-pressure heat recovery steam generators and use of gas turbine cooling air heat rejection were investigated. Each proposition yielded a certain contribution to efficiency. While the evaluation did not involve economics, some selective judgments were made with regard to how many of the various contributors were incorporated into the final cycle configuration.

1.1.3 Cycle Selection

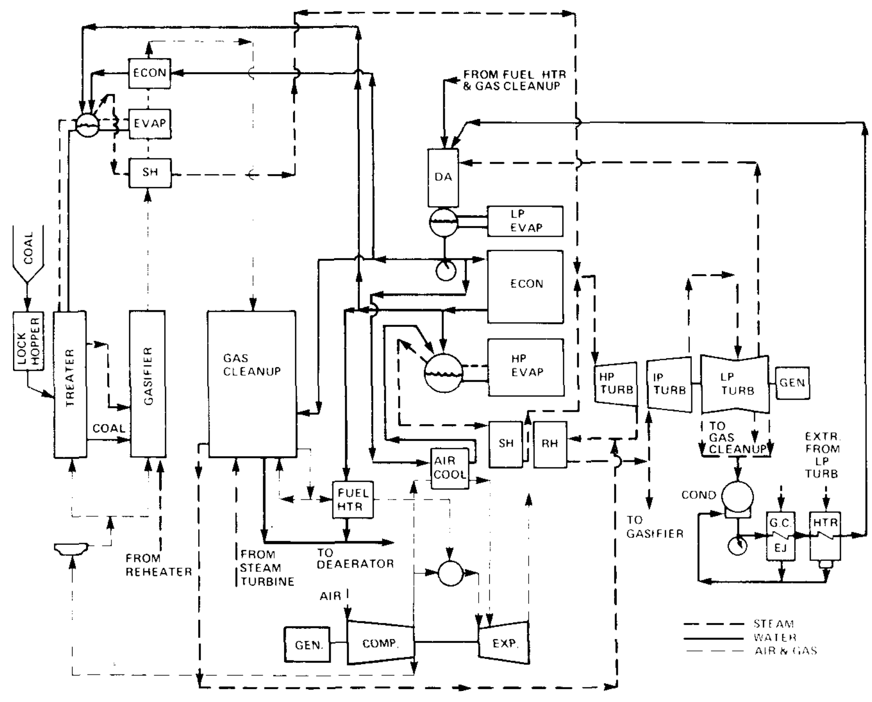
The final performance data for the high-temperature air-cooled gaseous fuel-fired gas turbine/combined cycle had some variance with the preliminary data. The gasification system, although remaining the IGT U-Gas system, changed in the areas of heat and material balance sufficiently to cause an alteration to the combined cycle configuration. Also, the gas cleanup system was changed from the Sulfinol to the Selexol process. The final gas turbine performance also changed in the areas of exhaust flow, exhaust temperature and output.

One of the chief causes for change in the cycle configuration was due to the marked change in the treater energy. Considerably less air is used in the treater now than was used in the preliminary analysis. Consequently, considerably less energy is available in the treater to produce high pressure steam.

Another important change centered in the gasifier. The temperature of the raw gas leaving the gasifier is 1900°F rather than 1730°F, which existed in the earlier configuration shown on Figure 1.1-17. In addition, the coal analysis changed which included a 260 percent increase in moisture. The steam and water requirements changed somewhat in the cleanup system, as well. Previously, 140 psi and 70 psi steam plus hot water were sent to the cleanup processes. The new data reflect steam required at 80 psi plus 700 psi hot water. In addition, condensate quality water at 50 psi is returned from the cleanup process to the deaerator; and, 650 psi, dry and saturated steam from the Claus unit, is joined with the cold reheat steam from the steam turbine prior to entering the reheater. Figure 1.1-18 is a diagram depicting the final cycle configuration. The 80 psi steam for the gas cleanup is extracted from the steam turbine as was done previously. Finally, utilization of the gas turbine air cooler heat rejection used for fuel heating in Figure 1.1-17 reverted back to feedwater heating shown on Figure 1.1-18. This change does not affect the cycle performance.

In the preliminary High-Temperature Turbine Technology combined cycle studies, the best performance resulted from two main features:

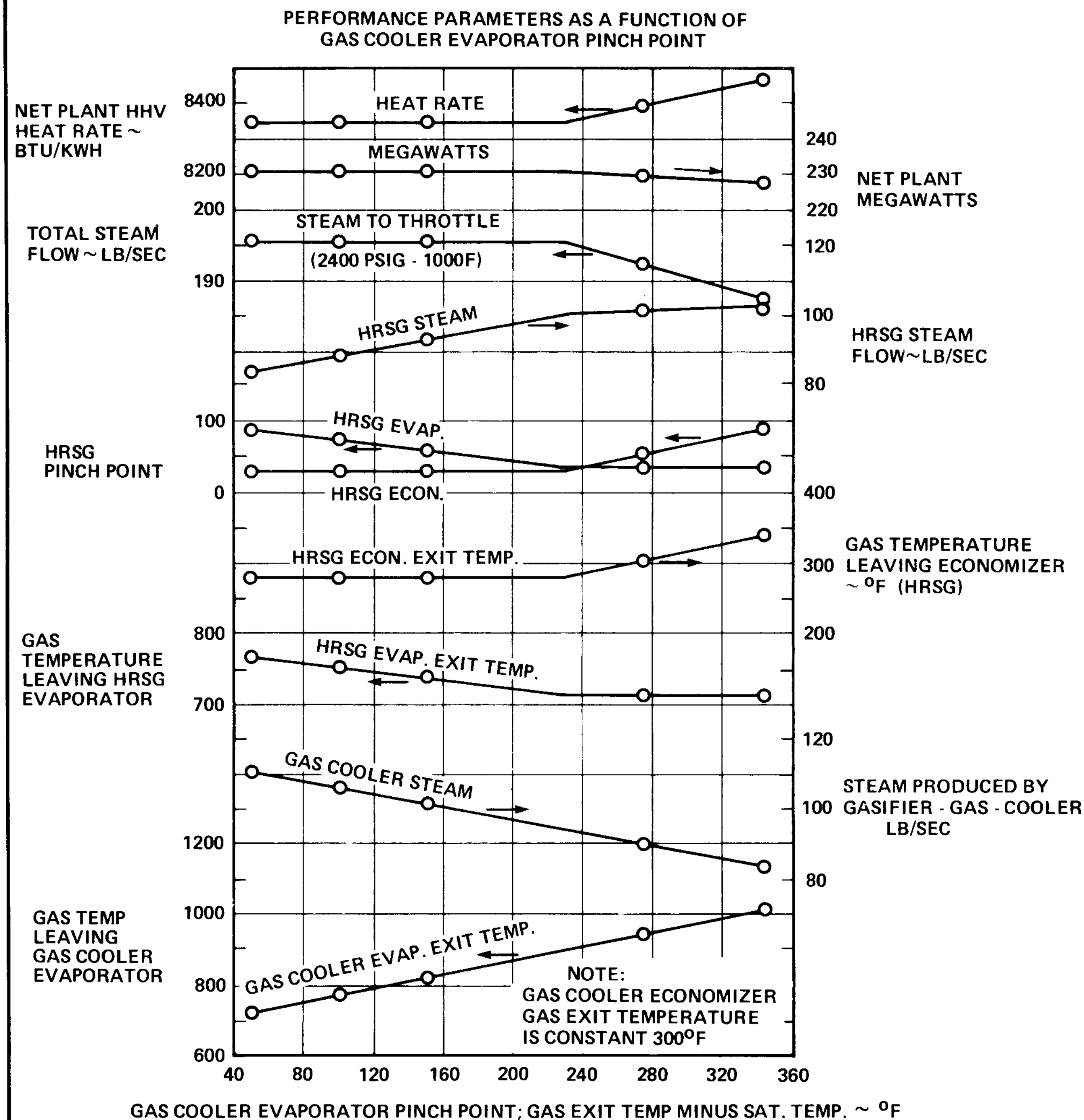
(1) Raising the steam conditions from 1450 psig-1000°F-1000°F-2.5 In. HgA to 2400 psig-1000°F-1000°F-2.5 In. HgA.



COAL-GAS COMBINED CYCLE
Figure 1.1-18

(2) Splitting the feedwater stream so that only a portion of the feedwater to the gasifier system was heated in the HRSG economizer.

These features were carried over to the final configuration. The analysis continued a step further by varying the percent of the feedwater stream being split. The variation in flow to the HRSG economizer and the accompanying variation of feedwater to the gas cooler economizer caused the high-pressure evaporator pinch-points in the gas cooler and HRSG to vary. Since the raw gas temperature leaving the gas cooler economizer is constant at 300°F, and since the feedwater temperature entering the gas cooler economizer is constant at 250°F, the "cold end" approach remained constant at 50°F (300-250). Therefore, the amount of steam generated in the gas cooler is directly affected in a linear fashion by the percent feedwater split. This is not strictly true in the case of the HRSG. Figure 1.1-18 shows a low-pressure evaporator in the HRSG whose function is to aid in feedwater heating. It is intended to function at part load and off-design, not at full load, ISO. However, as the amount of feedwater to the HRSG economizer is diminished, a point is reached wherein the economizer duty is satisfied at temperatures greater than 280°F. (The minimum stack temperature for the HRSG). Therefore, the LP coil commences to produce steam to aid the feedwater heating and deaeration processes. Figure 1.1-19 is a plot of the significant performance parameters in the cycle as the percent feedwater is varied. Note, however, that the percent feedwater split is represented by the gas cooler evaporator pinch-point on the x-axis.

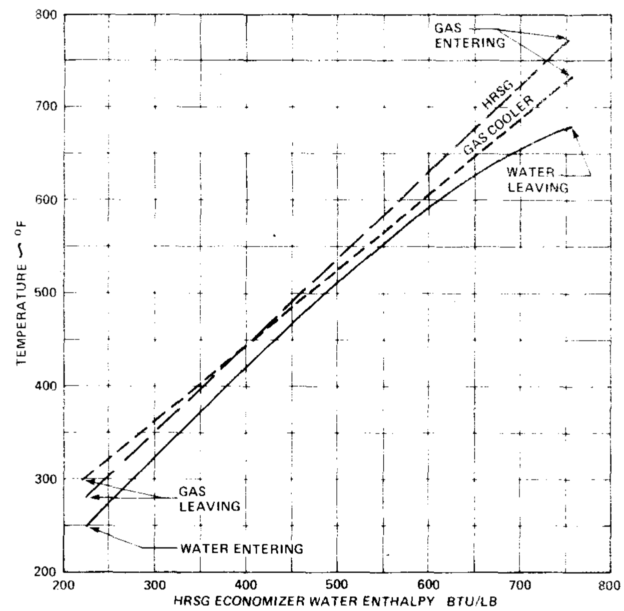


HIGH-TEMPERATURE GAS TURBINE COMBINED CYCLE FIRED TO 2600°F ON COAL-DERIVED LOW-BTU GASEOUS FUEL

Figure 1.1-19

The calculated performance data represented by the circled points commence at the left with the gas cooler pinch-point equal to 51°F. The heat rate, total steam-flow and megawatts are unaffected until the minimum HRSG pinch-point is reached. The minimum pinch used in this analysis is 35°F, which corresponds to 714°F gas temperature leaving the HRSG economizer. Therefore, the actual feedwater split to be used can be evaluated on the basis of equipment size and cost, as long as the evaluation is made in the areas of the curve where heat rate and output are constant.

The initial performance point, where the gas cooler and HRSG evaporator pinch-points are 51°F and 88°F, respectively, are examined further in Figure 1.1-20. The solid line shows the temperature and enthalpy characteristic of the feedwater in the economizers. The dashed lines show the gas temperatures in the HRSG and gas cooler economizers. Although the water leaving and gas entering temperatures reflect the 51°F and 88°F evaporator pinch-points, it is also seen that the real economizer pinch-point occurs within the temperature extremes and in effect is about 12°F for the gas cooler and about 22°F for the HRSG. But since the plant power and efficiency is constant for a wide variation of gas cooler evaporator pinch-points, the final optimization can be performed on an economic basis in a later phase of the program. It must be pointed out, however, that the 35°F pinch-point used for performance calculations in the HRSG on Figure 1.1-19 was used to get the trends in overall performance at the right band side of the curves. The break in the plots may have to take



HIGH-TEMPERATURE GAS TURBINE COMBINED CYCLE
GAS AND WATER TEMPERATURE AND ENTHALPY IN HRSG HIGH-PRESSURE ECONOMIZER AND GAS COOLER ECONOMIZER
Figure 1.1-20

place at a smaller gas cooler evaporator pinch-point, say 200°F, where the HRSG evaporator pinch-point is about 45°F. The final results, however, will still show the performance becoming more critical as gas cooler pinch-point is increased beyond that point.

In later phases of the program, new or altered information may change the performance figures somewhat. It is also possible that parameters will change sufficiently to cause a change in the configuration of the cycle. Heating the fuel gas to higher temperatures shows promise of improving the cycle efficiency. Those elevated fuel temperatures may cause the steam conditions and feedwater heating scheme to change.

The optimized heat balance, based on heating the fuel gas to 620°F, is shown on Figure 1.1-21. The heat balance achieves a calculated heat rate of 8336.2 Btu/KwH at a power output of 231,346 KW for a single gas turbine cycle. The selection of the four (4) gas turbine plant, in Section 1.2, results in a plant power output of 925,384 KW

1.2 PLANT ARRANGEMENT SELECTION

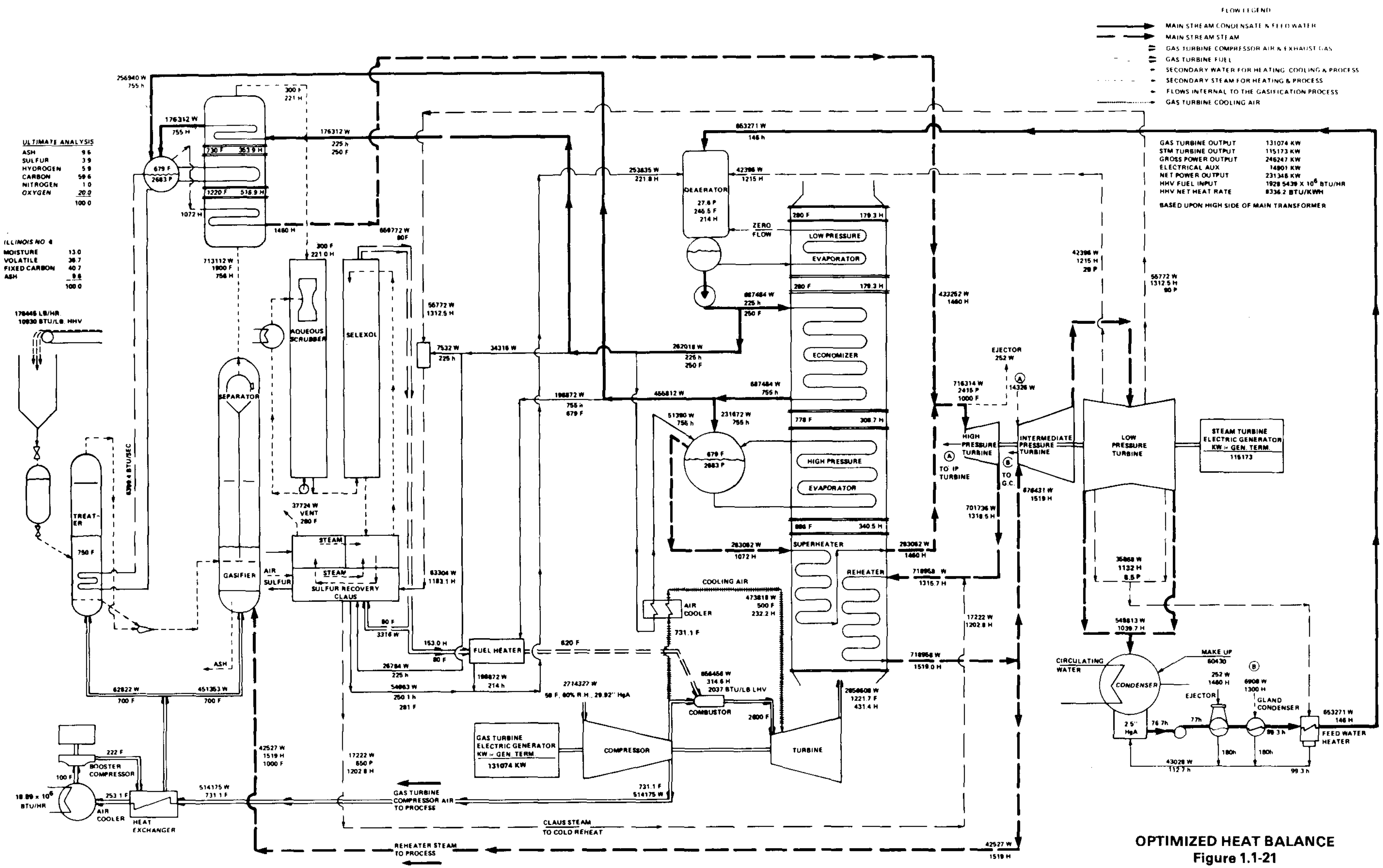
Technical considerations are the primary input in developing plant size and arrangement. However, as displayed in the ECAS study, there is associated with each plant configuration an energy production charge or cost of electricity (COE). Realizing that the ultimate goal is to have a plant of high efficiency as well as low cost power, the factors that influence the latter must be considered.

There are several factors associated with the coal gasification process point to a plant designed for continuous base operation. First, the gasification plant like other chemical processes lends itself to continuous operation. Secondly, startup of the gasification system is time consuming, making it less desirable for intermediate or cyclic duty; finally, hot standby and startup energy consumption associated with a gasification system are larger than other fossil-fired plants, again a negative factor for cyclic duty.

The combined cycle utilizing an unfired HRSG was selected for optimum performance. The final plant size is determined by using multiples of combustion turbine-HRSG units with a steam turbine unit.

It was decided to use an even number of combustion turbine-HRSG units with a single steam turbine generator unit, thus providing symmetry in plant arrangement.

Power plants recently purchased and installed by utilities for system expansion have, in general, been larger than 600 MW. Available sites, licensing and other siting clearances required, together with lower installed cost, give reason to this trend and support its continuance. The design of this plant must be competitive with other forms of base generation.



OPTIMIZED HEAT BALANCE
Figure 1.1-21

Four (4) combustion turbine-generator-HRSG units, each nominally rated at 131 MW, were selected for the reference plant yielding a gross plant rating of approximately 985 MW.

The equipment arrangement of the plant, shown on Figure 1.2-1, follows closely the arrangement used successfully in the Westinghouse PACE plants. The combustion turbine-generator units are installed in pairs to each side of the steam turbine unit at essentially floor elevation. Unit size along with simplicity of operating control and desired flexibility, are the principal factors for having a one-on-one gasifier to combustion turbine arrangement. The equipment of the gasification system will be installed outboard of the HRSG, essentially centered and on-line with its interfaces - the coal supply and the combustion turbine-HRSG unit. This arrangement simplifies associated fuel, steam and water, piping while keeping the coal and ash at the greatest distance from the switchyard and the air compressor inlets.

The steam turbine-generator unit will be installed on a raised pedestal foundation in the center of the plant. The main control room will also be located at this elevation in the center of the plant. All turbine-generator units will be housed in a turbine room enclosure having a crane and equipment laydown space for maintenance.

Packaging of auxiliary equipment associated with each major plant component will be part of the plant design. The packaging concept offers many advantages:

1. Permits standard design for producibility where volume production of like units is involved, as is the case with the combustion turbine - HRSG units.

2. Standard design and design control allows single corrective action to be taken on problems to affect installed and production units.

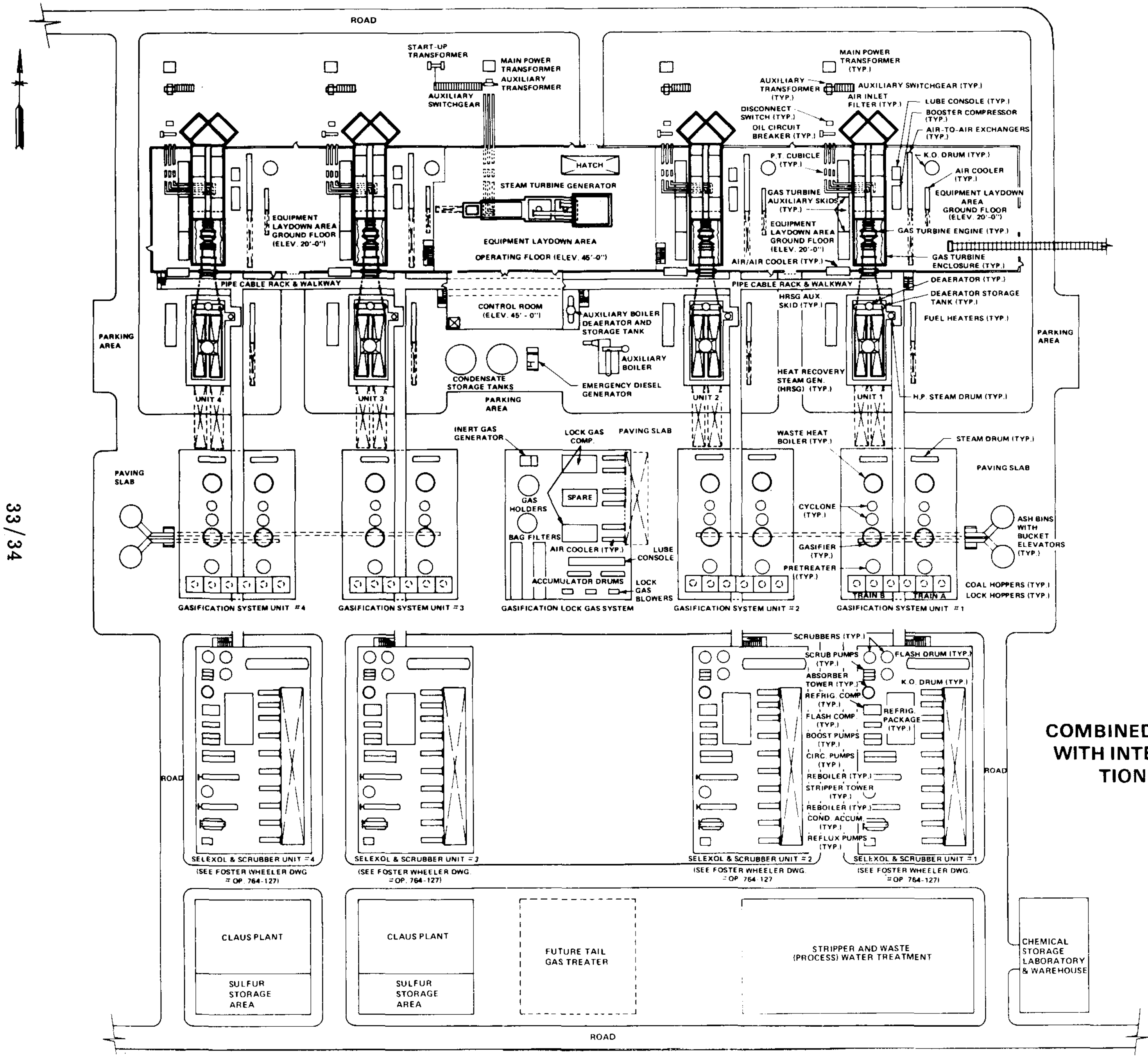
3. Allows maximum factory testing.

4. Minimizes engineering interfaces for installation and construction.

5. Reduces shipping losses.

6. Reduces installation time.

Packages of the combustion turbine-HRSG units will be located adjacent to the unit, whereas, the auxiliary components of the steam turbine unit will be mounted beneath the turbine-generator unit.



COMBINED CYCLE GAS TURBINE SYSTEM WITH INTEGRATED LOW-BTU GASIFICATION PLANT ISLAND GENERAL ARRANGEMENT

Figure 1.2-1

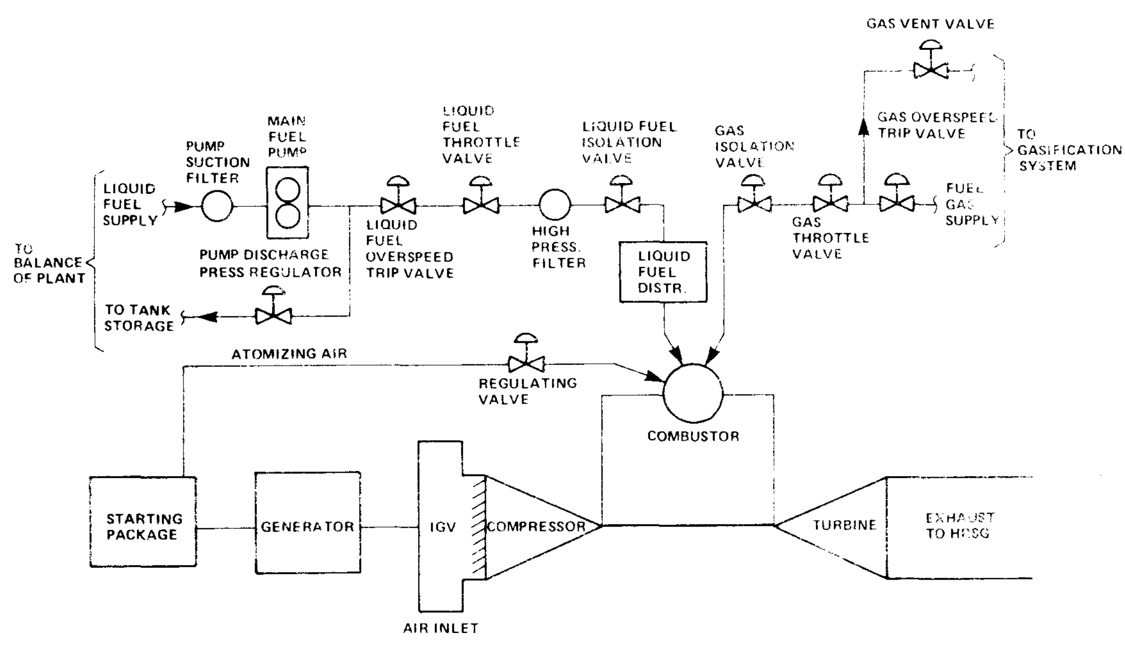
SECTION 2
FLUID SYSTEMS

This section of the plant reference design describes the various fluid systems necessary for the power block equipment to operate and be maintained.

2.1 FUEL SYSTEM

The fuel system to be used for the combustion turbines will be a dual fuel system - gas and distillate oil, with coal-derived gas being the primary fuel. The distillate oil system will be used for startup and in abnormal running conditions when fuel gas supply is interrupted.

A schematic diagram of each fuel system in the power block area is given in Figure 2.1-1. The supporting atomizing air system for startup on distillate oil is also shown.



POWER BLOCK FUEL SYSTEM

POWER BLOCK FUEL SYSTEM
Figure 2.1-1

Fuel gas first enters the power block fuel system through an overspeed trip valve. This valve, as its name implies, is a tight shutoff valve that closes when oil pressure to the turbine shaft overspeed trip device is lost. This trip circuit is interlocked with all turbine-generator trips.

The total fuel flow is regulated with a signal from the control system by the throttle valve.

The isolation valve is also a tight shutoff valve and serves the following:

1. Allows overspeed trip valve to be open as required for startup and running, while providing a final tight shutoff of fuel to nozzles.

2. Acts as a backup to the overspeed trip-valve on emergency shutdowns, satisfying the dual shutoff requirement.

The gas vent-valve allows venting to the atmosphere of gases in the piping between the isolation and overspeed trip-valves when they are closed. The vent-valve is closed when the overspeed trip-valve is open.

In the fuel oil system, fuel is first passed through a five (5) micron main oil pump suction filter and is then raised in pressure by a positive displacement type pump. After passing through the overspeed trip and throttle valves, another five (5) micron high-pressure filter is used to insure fuel cleanliness to the nozzles. The fuel then passes to the isolation valve and a flow distributor, which equally divides the fuel flow to each of the fuel nozzles. The excess fuel flow discharged from the fuel pump and not delivered to the turbine is bypassed back to storage via the pump discharge pressure regulating valve.

At low turbine speed during ignition and startup, supplementary air for atomizing the fuel oil is required. This air comes from a shaft mounted blower, integral with the starting package, with its delivery pressure to the nozzles controlled by the atomizing air regulating valve.

Fuels delivered to the power block supply connection have the following physical characteristics:

	Coal Gas	Distillate Oil
Min. Viscosity, SSU	-	35
Fuel Temp., ^oF	620^oF	$\leq$ 250^oF
Max. Viscosity, SSU	-	70
Supply Pressure, psig	270	25
HHV, Btu/SCF	142.6	-
Btu/#	2,195	19,300
Molecular Wt.	24.61	-

2.2 STEAM, FEED AND CONDENSATE

The components of the steam cycle portion of the power block are interconnected through a piping system, which for the purpose of this discussion, is broken down into three (3) systems: steam, feed and condensate.

2.2.1 Condensate System

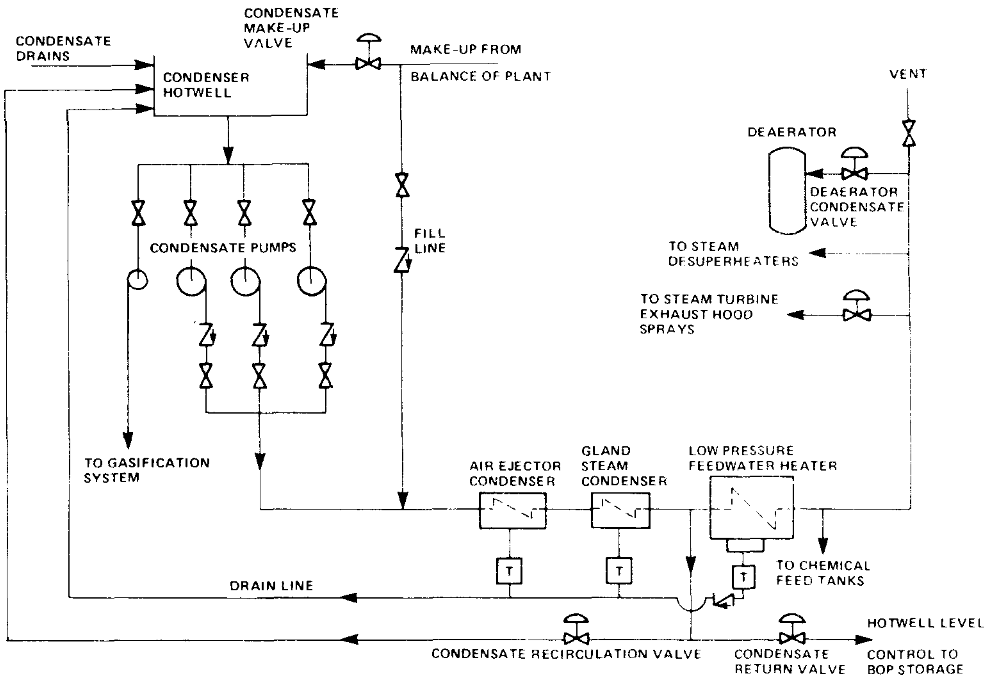
The principal role of the condensate system is to move the condensed liquid in the condenser hotwell, back to the HRSG.

OPERATION:

In addition, the condensate system provides:

1. Condenser hotwell water inventory control by:
   - admitting demineralized water from balance of plant storage to compensate for leakage and blowdown.
   - exporting excess condensate to balance of plant storage.
2. Cool condensate to steam desuperheaters and to the steam turbine exhaust hood spray for temperature control.
3. Treated water to the solution tanks of the chemical feed system.
4. The cooling medium for the gland and air ejector condensers. By circulating the total condensate flow through these two (2) condensers in series flow, energy from within the cycle is added to the condensate, thereby reducing losses. (At low loads, condensate is recirculated back to the hotwell.)
5. Hot degasification of condensate by means of the deaerating heater connected to the low-pressure section of the HRSG.

A flow schematic of the condensate system is shown in Figure 2.2-1. Two condensate pumps are used in normal operation, with the third pump being an installed spare. On-off operation of the third pump will be controlled by a pressure switch in the condensate system downstream of the pumps. The discharge head of the pumps will be selected to provide an operating pressure to the deaerator of 150 psia maximum, taking into account line loss and installation elevations. This pressure will assure adequate condensate delivery to the deaerator under all operating modes. A small amount of condensate is required by the gasification system. This will be supplied by a separate, suitably rated condensate pump.



CONDENSATE SYSTEM
Figure 2.2-1

Included as part of the condensate system are the drains from equipment such as the steam turbine and steam line drain traps. This condensate forms during startup and shutdown when steam condenses on the cold metal of the lines and turbine. To keep this liquid from entering the turbine blade path, drains are appropriately located to return the liquid to the condenser hotwell.

The system vent valve and fill line permits filling of the system prior to condensate pump operation. It is mandatory that the system be properly purged of air and kept full to prevent system water hammer and possible equipment damage.

Heat is added to the condensate by condensing steam used for the air ejectors and the steam turbine shaft glands. In addition, a closed feedwater heater will take low pressure steam extracted from the steam turbine for the final stage of heating the condensate prior to the HRSG, deaerator.

Leakage of condensate into the deaerator during hot, ready-to-start conditions will be avoided so as to prevent chilling and reduce drainage of the excess water. The hot, ready-to-start condition cannot be maintained for any prolonged period, if the energy level is allowed to deteriorate as a result of leakage.

DESIGN CODES:

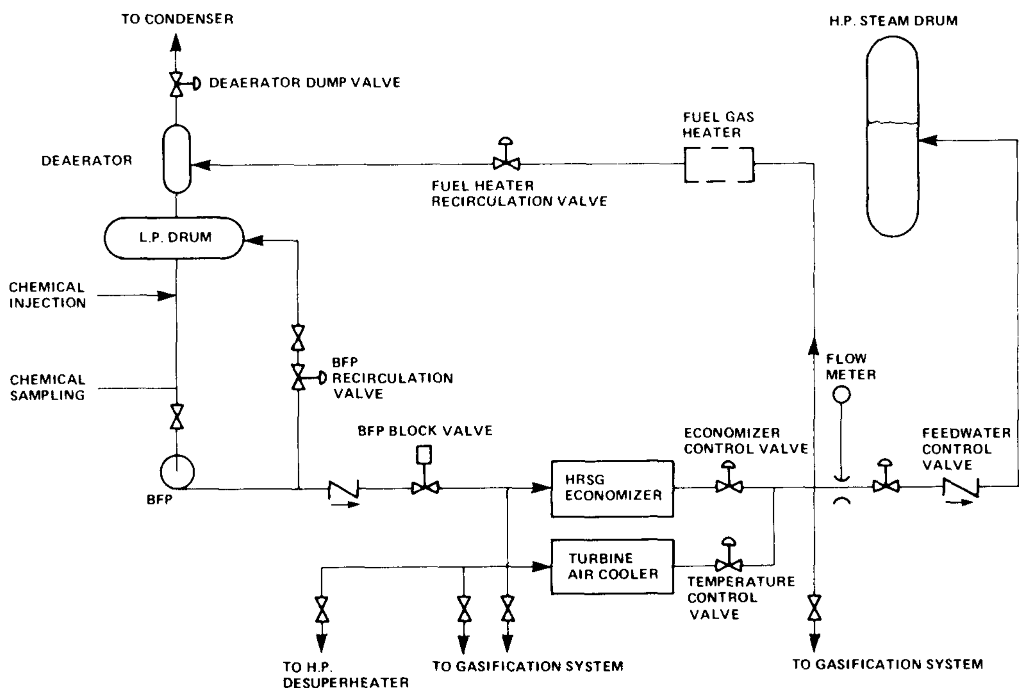
Operating pressure and temperature permits the use of standard carbon steel materials in the fabrication of this system. Design and manufacture will be in accordance with the Power Piping Code, ANSI B 31.1.0.

2.2.2 HRSG Feed System

The HRSG feed system comprises the boiler feedpump, control valves and interconnecting piping. The system is schematically shown in Figure 2.2-2.

OPERATION

The boiler feedpump (BFP) takes deaerated water from the low pressure storage drum and increases its pressure before the water receives additional heat in the economizer section of the HRSG and a parallel turbine cooling air heat exchanger. Chemical sampling and treatment of high pressure drum water for oxygen and pH control is done at the suction side of the BFP at the lower pressure. The boiler feedpump will have a minimum flow bypass to prevent the pump being overheated should it be operated at shutoff head. Shutoff valves will also be provided in the suction and discharge piping of the BFP to permit maintenance of the pump without having to drain the HRSG.



HRSG FEED SYSTEM
Figure 2.2-2

High pressure condensate from the BFP discharge will be used as the cooling source in the high pressure main steam bypass desuperheater. The BFP operating characteristics will be selected to provide this flow in addition to rated steam flow.

Two (2) sidestreams of water to the gasification system are taken from the BFP discharge, upstream of the HRSG economizer and turbine cooling air heat exchanger and two (2) sidestreams are taken downstream. One of these lines takes the hot water from the HRSG economizer and heats the fuel gas before the gas is burned in the combustion turbine. The cool, high pressure water coming from the fuel gas heater is then throttled and discharged into the deaerator. This line will be operable to recirculate economizer water back to the deaerator even when the combustion turbine is operating on oil fuel. The remaining three (3) lines going to the gasification system will be fitted with isolation valves, which will allow operation of the combustion turbine-HRSG unit independent of its associated gasification train.

In the event that energy is added to the deaerator at a faster rate than it is being absorbed, the pressure in the deaerator will rise. To prevent the deaerator pressure from rising beyond limits, the excess energy is vented back to the main condenser by means of a deaerator dump valve. Feedwater to the HP steam drum will be taken from the discharge of the HRSG economizer and turbine cooling air heat exchanger and will be controlled to maintain drum level and balance steam generation.

DESIGN CODES

This system will be designed in accordance with the Power Piping Code, ANSI B 31.1.0 up to the BFP discharge check valve. The remainder of the system will be in accordance with the ASME Boiler and Pressure Vessel Code, Section 1.

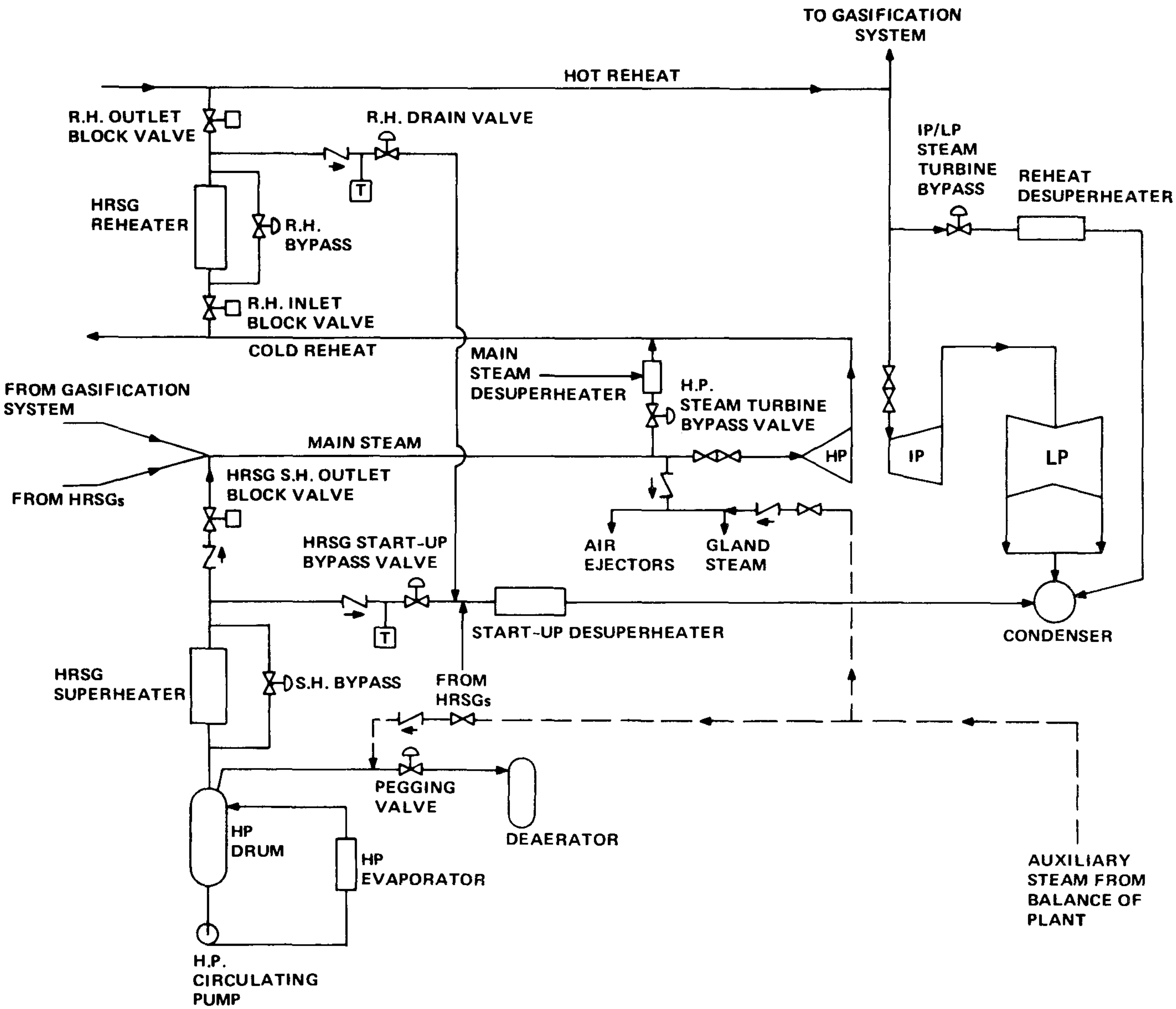
2.2.3 Steam System

The Power block steam system connects the HRSGs, the gasification system and the main steam turbine. The flow schematic of this system is given in Figure 2.2-3. The steam turbine is connected to the power block steam system and the gasification steam system by means of three (3) steam headers. They are:

1. The main steam header which connects the HRSG superheater outlets to the throttle of the HP steam turbine.

2. The cold reheat header, which connects the discharge of the HP turbine to the reheater inlets of each HRSG.

3. The hot reheat header which connects the HRSG reheater outlets to the IP turbine inlet. In addition, a connection from this line is made for steam going to the gasification system.



POWER BLOCK STEAM SYSTEM
Figure 2.2-3

OPERATION:

The steam system will contain full capacity steam turbine bypass valves and desuperheaters. This bypass system will give the plant maximum operating flexibility by offering unlimited combustion turbine operation, independent of the steam turbine. A secondary, or startup bypass system will be also integrated into the overall steam system. Individual combustion turbine-HSRG units may then be started and dried out, before they are brought on-stream with the main steam system at rated temperature and pressure. Steam to power the air ejectors and to seal the shaft glands of the steam turbine will be drawn from the main steam header when the plant is in operation. Steam required during startup and shutdown will be provided from the auxiliary boiler provided with balance of plant. Steam bypasses are provided for the superheater and reheater of each HRSG unit to control steam outlet temperature as operating conditions may demand. In addition, each HRSG superheater and reheater will be fitted with drains from their respective outlets, to the main condenser. These drains remove the condensate formed during combustion turbine shutdown, when the cooling exhaust gases passing over the tube surface turns each heat transfer section into a condenser, condensing the steam that remains inside the tubes.

A steam connection between the HP drum and the deaerator permits minimum pressure to be maintained in the deaerator during the hot, ready-to-start condition. Auxiliary steam from balance of plant will augment the steam bottled up in the HP drum during the hot, ready-to-start period. Each HRSG will be connected to the steam headers through shutoff valves. This allows a combustion turbine/HRSG unit to be removed and isolated from an operable steam system.

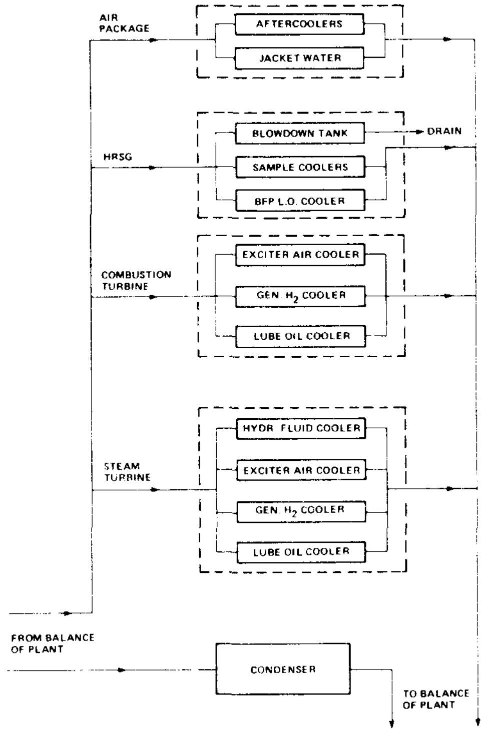
DESIGN CODES:

This system will be designed to comply with the Power Piping Code, ANSI B 31.1.0 and the ASME Boiler and Pressure Vessel Code, Section I.

2.3 COOLING WATER

Various fluid systems within the power block require dissipation of low energy heat. These sources, shown in Figure 2.3-1, include the following:

Fluid Systems	Sources
Air Package	After coolers. Jacket water.
HRSG	Blowdown tank. Sample coolers. Boiler feedpump lube oil cooler.
Combustion Turbine	Exciter air cooler. Generator hydrogen cooler. Lube oil cooler.
Steam Turbine	Hydraulic control fluid cooler. Exciter air cooler. Generator hydrogen cooler. Lube oil cooler.
Condenser	Normal operation.



POWER BLOCK COOLING WATER SYSTEM
Figure 2.3-1

Removal of the low energy heat is accomplished using auxiliary cooling water circuits, which interface with balance-of-plant.

Cooling water flow to the instrument and service air package aftercoolers and the coolers for each turbine-generator unit is automatically regulated by a temperature responsive flow control valve. The maximum cooling water supply pressure will be 100 psig.

2.4 GENERATOR HYDROGEN AND CARBON DIOXIDE SYSTEM

The generator gas system consisting of hydrogen and carbon dioxide is an auxiliary support system for the hydrogen cooled generator. The gas system serves the following functions:

1) Provides a manual means of safely adding hydrogen to and removing hydrogen from the generator cooling system, using carbon dioxide as a scavenging medium.

2) Maintains the gas pressure in the generator at the desired value.

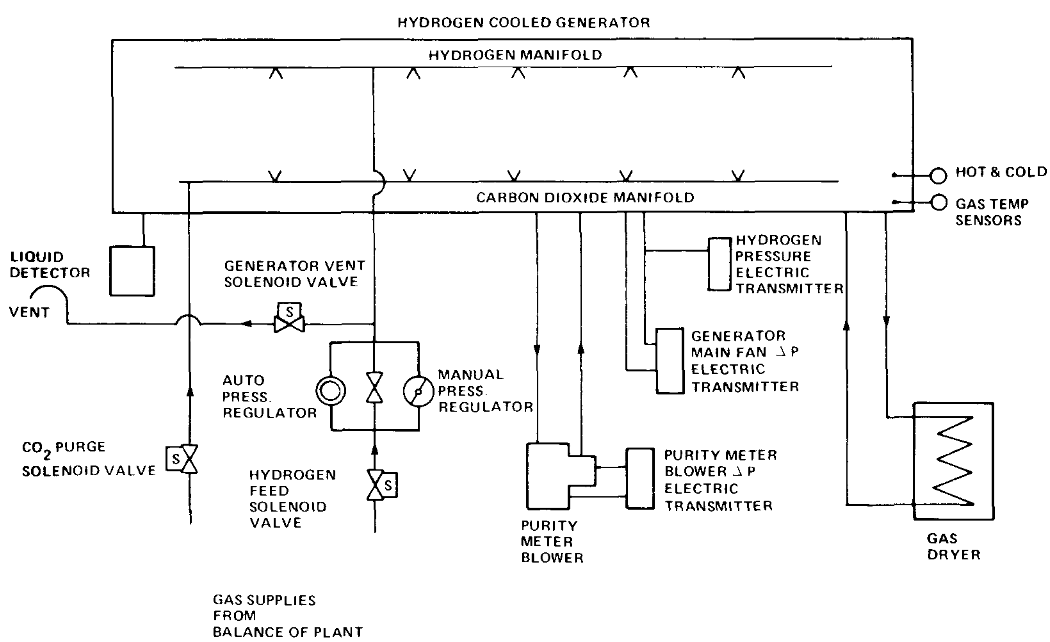
3) Continuously monitors the properties of the gas in the generator.

4) Dries the gas to remove any water vapor which may form from seal leakage.

5) Provides an automatic control with manual backup.

The hydrogen and carbon dioxide gas system for each generator in the power block is schematically shown in Figure 2.4-1. Hydrogen and carbon dioxide gas supply to this system is taken from bulk storage, included as part of balance of plant, with supply conditions being as follows:

Gas Supply Conditions	Combustion Turbine - Generator		Steam Turbine Generator	
	CO_2	H_2	CO_2	H_2
Pressure, psig	125 max.	60 - 90	125 max.	75 - 100
Temperature, F	0 min.		0	
Flow	200 scfm	400 scfd	250 scfm	400 scfd



POWER BLOCK H_2 and CO_2 SYSTEM
Figure 2.4-1

SYSTEM COMPONENTS:

The hydrogen gas supply includes the necessary valves, gauges and regulators to permit introducing hydrogen into the generator and controlling the gas pressure either manually or automatically. One regulator is manually set for the normal operating pressure. The other regulator is preset at 0.5 psig, and is used to accurately maintain low machine pressure during a prelonged cold, ready-to-start condition. The generator vent and carbon dioxide purge solenoid valves permit admitting carbon dioxide to the generator during the gas (air or hydrogen) purging operation. The liquid detector senses and provides an alarm, should liquids enter the machine as a result of oil leaks, a defective cooler, or extensive condensation.

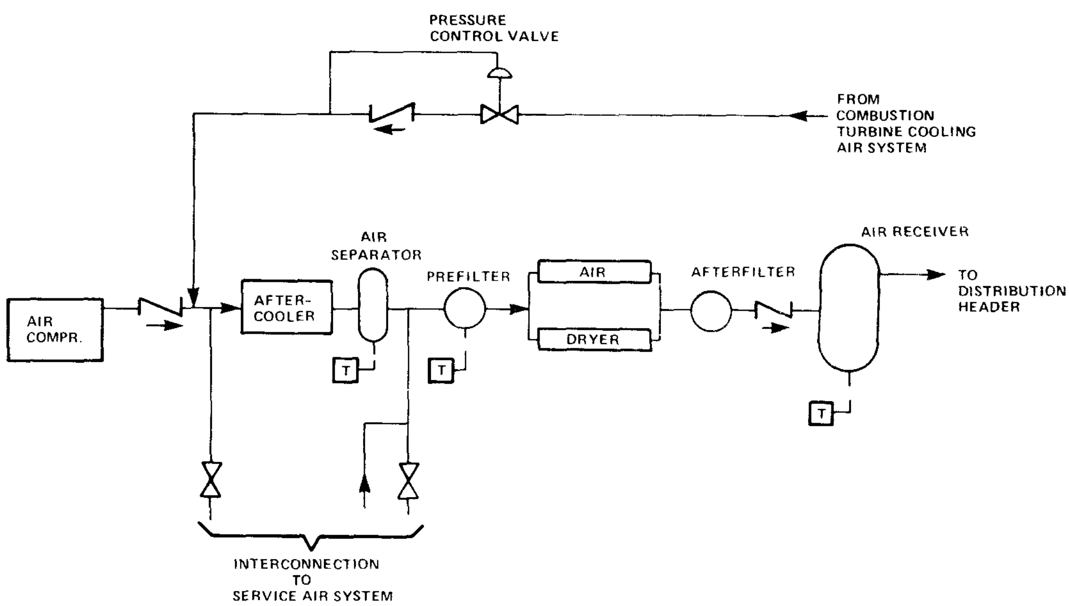
A gas dryer consisting of a chamber filled with activated alumina absorbent material is connected across the generator blower, so that gas is circulated through the dryer whenever the machine is running. The absorbent material will take up about two (2) pounds of water, after which it can be dried out by disconnecting the dryer from the machine and then heating with a built-in electric heater. Before and during the drying process, air is forced through the dryer by a small blower to remove the moisture. A thermostat protects the dryer against overheating. The dryness of the active material can be determined by the color of the humidicator material as seen through the window in the bottom of the dryer. The monitoring and control of the gas dryer is a manual operator function.

The purity of the gas in the generator is determined by use of the hydrogen purity indicating transmitter and the purity meter blower. The purity indicating transmitter is a differential pressure instrument which measures the pressure developed by the purity meter blower. An induction motor, loaded very lightly so as to run at practically constant speed, drives the purity meter blower and circulates the gas drawn from the generator housing. Thus, the pressure developed by the purity meter blower varies directly with the density of the machine gas. Gas density is dependent upon the ambient pressure and temperature as well as the purity of the gas being sampled. The purity indicating transmitter is provided with automatic compensation for pressure and temperature variations so that the scale reading is in terms of actual purity.

Two switch assemblies are provided with the purity indicating transmitter which are set to produce a "hydrogen purity high or low" alarm when the differential pressure falls below or exceeds pre-determined limits.

2.5 INSTRUMENT AIR SYSTEM

The instrument air system integral to the power block area of the plant provides oil and moisture free air (-40^{o}F dewpoint) at a maximum pressure of 125 psig for the instrument air requirements of the total plant. The system is shown schematically in Figure 2.5-1.



POWER BLOCK INSTRUMENT AIR SYSTEM
Figure 2.5-1

The instrument air compressor is a water-cooled machine which discharges its hot compressed air into an aftercooler. As air discharging from the aftercooler is cooled, condensing moisture will collect in the separator and be drained through automatic traps. Moisture carried over from the aftercooler air separator will be picked up and removed by the air dryer. A pre-filter upstream of the air dryer and an after-filter on the downstream side also remove moisture to the drain system. The instrument air receiver tank provides storage. This tank also has a drain trap to permit condensate discharge. The instrument air system is cross-connected to the service air system, which allows one system to back up the other.

Compressed air is taken from the cooling air system of the combustion turbine and piped into the instrument air system upstream of the aftercooler. The pressure of the incoming air is reduced by automatic pressure control valves to 125 psig maximum. All instrument air is supplied from the combustion turbine when it is operating. Should the air pressure in the receiver tank fall below 95 psig, the motor-driven air compressor will automatically start and increase the pressure to 125 psig.

2.6 SERVICE AIR SYSTEM

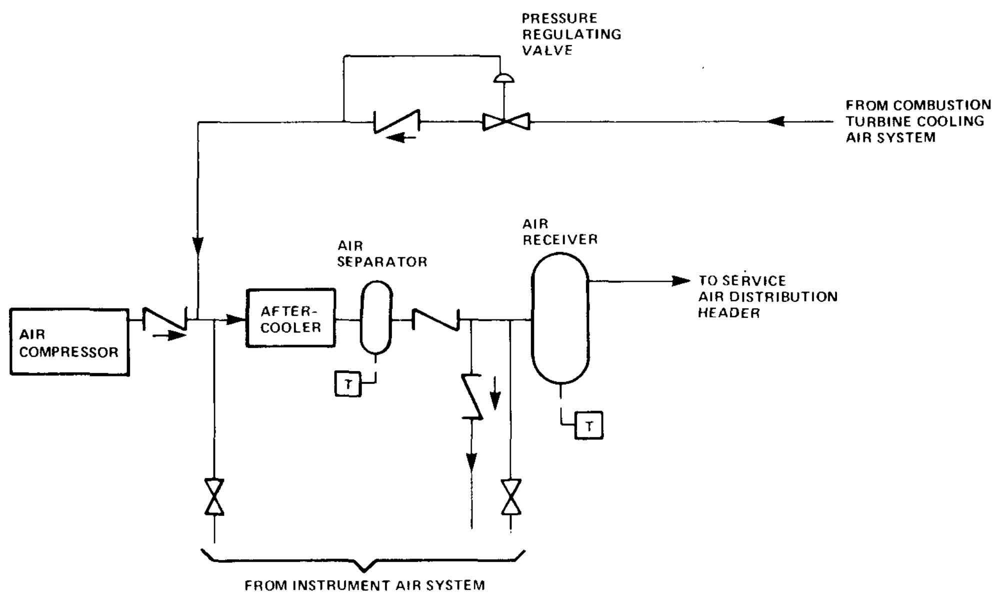
The function of the service air system in the power block is to provide oil free air for general service and plant requirements, such as air-operated hand tools. In addition, since the air compressor is the same oil-free design as the instrument air compressor, it serves as a backup to the instrument air system and is piped accordingly.

The discharge of the water-cooled air compressor is cooled in an aftercooler, with condensing moisture collecting in the separator and drained through automatic traps. The discharged air is then piped to the service air receiver and to the instrument air system upstream of the pre-filter.

In backup operation to the instrument air system, air will first be drawn from the service air receiver tank. Should the pressure fall below 90 psig in this receiver, the service air compressor will start and increase system pressure to 125 psig.

The service air system is cross connected to the compressed air of the combustion turbine in the same manner as the instrument air system.

The flow schematic of the service air system is shown in Figure 2.6-1.



POWER BLOCK SERVICE AIR SYSTEM
Figure 2.6-1

2.7 LUBRICATING OIL SYSTEM

DESCRIPTION:

The purpose of the lubricating system is to provide clean oil at the required temperature and pressure to all bearings of the turbine-generator shaft. As an auxiliary to the lube oil system, a seal oil system is supplied to contain hydrogen pressure within the generator cooling system.

Differences exist between the lube oil systems of the combustion and steam turbine generator units, mainly because of the size and number of bearings associated with each. As an example of system size, the lube oil reservoir capacity for the combustion turbine unit is 2,500 gallons, whereas, the reservoir for the steam turbine unit is 7,000 gallons of oil, almost three (3) times larger.

Certain features or safeguards are standard in lube oil system design. They include:

1. Starting and turning gear equipment are electrically interlocked with the lube system so that the turbines cannot be rotated without lubricating oil pressure.

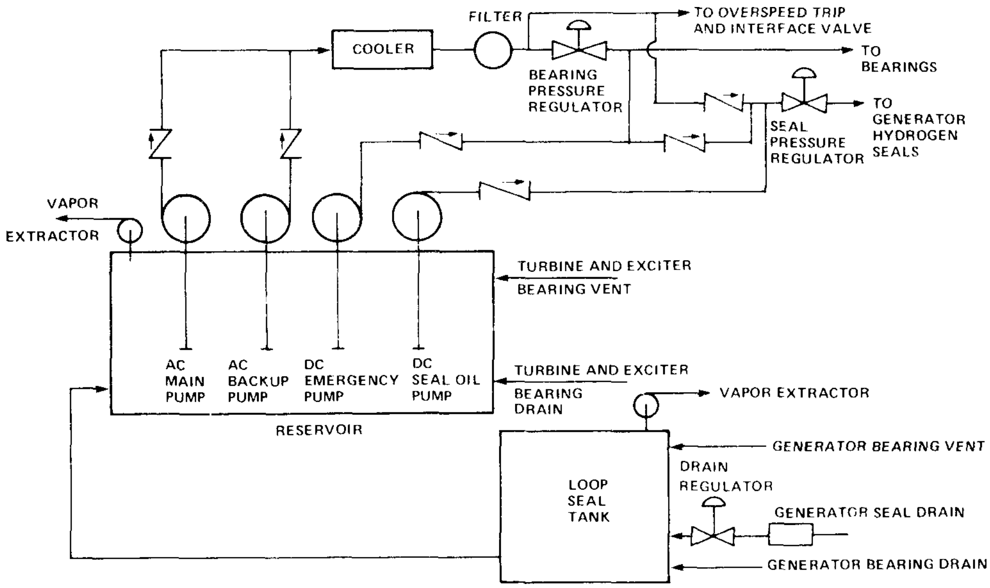
2. A dc motor-driven emergency pump is provided to permit a safe shutdown and turning gear operation in the event that the main or backup oil pump does not develop sufficient flow, or in the event of an emergency shutdown coincidental with an ac power failure.

3. Higher pressure lubricating oil is provided to the shaft mechanical overspeed trip valve and the overspeed interface valve of the control system. Operation of the turbine mechanical trip device or the operation of a manual overspeed trip at the unit, results in a loss of oil header pressure. This opens the interface valve releasing the fluid pressure (EH fluid in the steam turbine and air in the combustion turbine) on the steam or fuel inlet valves, causing them to close.

This hydraulic trip circuit is a time proven, reliable system, and is the primary circuit for overspeed shutdown. The lube oil system for the combustion turbine-generator unit is shown schematically in Figure 2.7-1.

OPERATION - LUBE OIL SYSTEM

All lube oil pumps for the combustion turbine generator, including the main pump, are motor-driven centrifugal type pumps, mounted on the lube oil reservoir. The main and backup pumps are driven by ac motors, while the emergency lube oil pump is driven by a dc motor.



COMBUSTION TURBINE LUBE OIL SYSTEM
Figure 2.7-1

In placing the system into service, the main ac motor-driven pump is energized. At the same time, the dc motor-driven emergency pump will start, but will be shut off after the ac pump establishes bearing pressure. In normal operation, only the main pump is running. Should the discharge pressure of the main pump begin to fall, the backup pump will automatically start. Should the bearing header pressure continue to fall below a pre-set point, the unit will be tripped from service and the dc emergency pump will be energized. The oil from the main pump passes through an oil-to-water cooler to keep the oil within the desired temperature limits. The oil then passes through a full flow oil filter which insures a clean oil supply to the bearings, and a pressure regulator which maintains the desired bearing header supply pressure.

The combustion turbine-generator unit is designed for all equipment to be installed at essentially the same elevation. This arrangement does not permit well sloped, ventilated drain lines from the bearing cavities. It is therefore necessary to separately vent the bearing housings and the oil reservoir and maintain a partial vacuum to prevent bearing oil leaks. Venting is accomplished by piping each bearing housing vapor space to the lube oil reservoir vapor space. A motor-driven vapor extractor then purges the reservoir and bearing housings of oil vapors.

OPERATION - SEAL OIL SYSTEM

During normal operation, seal oil for the hydrogen seals of the generator is taken directly upstream of the bearing pressure regulator. Because the combined lube and seal oil requirements are small, it is practical to simplify the overall system and size the main and backup lube oil pumps to have sufficient discharge head to provide regulated seal oil at a minimum pressure of 6 psi above the operating hydrogen pressure.

Oil from the hydrogen side of the gland seal rings goes to two (2) defoaming tanks where most of the gas comes out of the oil. These defoaming tanks are located in the bearing brackets of the generator and drain to the hydrogen drain regulator.

The hydrogen drain regulator is a chamber containing an internal float valve, which regulates the oil level at the center of the chamber. Thus, the chamber provides an oil seal preventing the escape of gas from the generator through the hydrogen side seal oil drains.

Oil from the bearing side of the gland seal drains into the bearing cavity and then into the loop seal tank. Oil from the hydrogen drain regulator also drains into the loop seal tank.

The purpose of this loop seal is to prevent the hydrogen in the generator from escaping into the main oil reservoir in the event of failure of the generator hydrogen shaft seals. Without the loop seal this could occur as a result of a sudden surge of hydrogen through the drain line. This seal thus represents an additional safety feature.

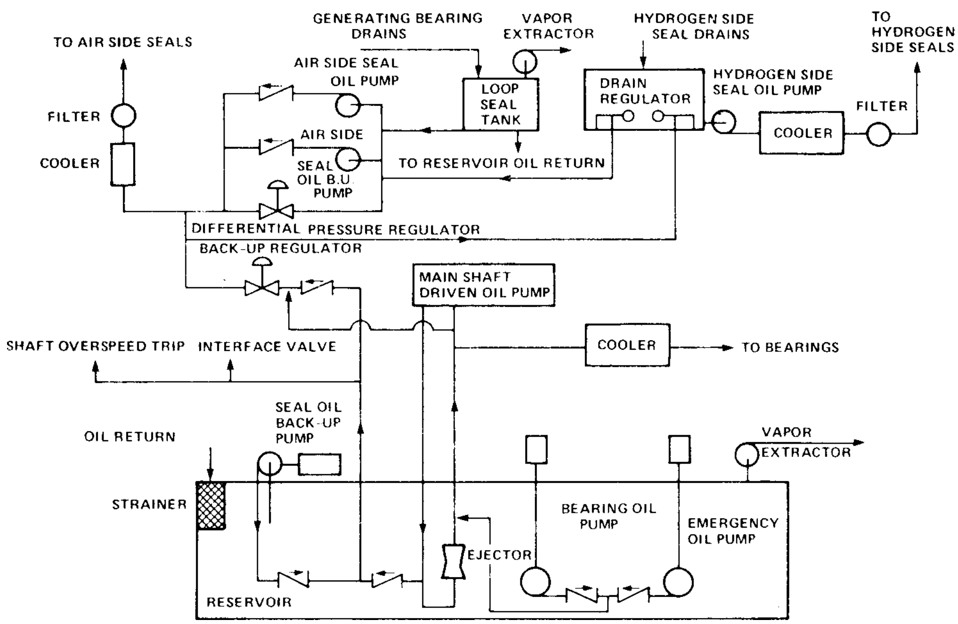
Since the loop seal is an obstruction to the bearing drain flow, the vapor extractor on the main reservoir is not able to vent the generator bearing drain system upstream of the loop seal. Therefore, an additional vapor extractor is provided on the loop seal tank and with the generator bearing cavity vents connected, the system is closed.

Backup seal oil is automatically supplied from the dc emergency and seal oil pumps in the event of an ac power failure. These pumps automatically maintain the hydrogen seal as the unit is tripped and the generator is vented to a lower pressure level of approximately 2 psig.

The lube oil system used on the steam turbine-generator units is shown on Figure 2.7-2.

The major differences in this system as compared to the one used on the combustion turbine, previously described are:

1. Bearing oil during normal operation of the steam turbine is supplied by a shaft-mounted centrifugal pump and an oil ejector. A positive pressure is



STEAM TURBINE – GENERATOR LUBE OIL SYSTEM
Figure 2.7-2

required on the suction of the centrifugal pump, since its installed elevation is higher than that of the reservoir. The oil discharged by the main pump operates the ejector, which supplies the main oil pump suction, as well as the bearing supply.

2. Cleanliness of the oil system is maintained by passing all of the oil coming from the drains through a full flow strainer before it enters the reservoir. In addition, oil is constantly being circulated through a purification system where sediment and water are removed.

3. Bearing header pressure is maintained on the steam turbine lube oil system without a pressure regulator, by design of the system and ejector selection.

4. As the installed elevation of the turbine-generator is considerably higher than that of the reservoir, drain lines are sloped so as to run only partially full. This allows the bearing housings to be vented back to the reservior via the drain lines.

5. The auxiliary seal oil system, the function of which is to lubricate the hydrogen seals of the generator and prevent hydrogen gas from escaping from the generator, employs a double shaft seal having an air side and a hydrogen side.

This system, used on large hydrogen cooled generators to minimize hydrogen consumption, requires separate motor-driven seal oil pumps for each side of the seal. Seal oil is supplied to the seals and maintained at a pressure of 12 psi above the generator gas pressure. Both sides of the gland sealing oil are held at the same pressure by means of equalizing valves, minimizing an interchange of seal oil between the air and hydrogen sides. See Figure 2.7-3 for diagram of seal.

While the interchange of seal oil at the gland seal rings is held to a minimum, minute variations in pressure over a long period of time may result in a gradual increase or depletion in the amount of oil in the two sides of the seal oil system. Therefore, a means is provided for the adding or removing of oil from the hydrogen side of the seal oil system. A hydrogen side drain regulator is provided for this purpose. This chamber has two float valves, one of which introduces oil into the chamber from the air side of the system if the oil level gets low, and the other of which allows oil from the chamber to flow to the air side of the system if the level gets high. The quantity of oil in the hydrogen side of the gland seal system is thus kept essentially constant, and the oil levels are properly maintained.

Oil returning from the hydrogen side of the gland seal rings goes to two defoaming tanks where most of the gas comes out of the oil. These defoaming tanks are located in the bearing brackets of the generator, and drain to the hydrogen drain regulator.

The air side seal oil pump receives its oil supply from the combined bearing and air side seal oil drain. It pumps part of this through a seal oil cooler to the air side of the gland seal ring, and returns part of it back to the suction side of the pump through a differential pressure regulator which maintains the air side seal oil pressure at the seals at 12 psi above the generator gas pressure. A motor driven air side seal oil backup pump is provided which circulates oil in the same manner.

The hydrogen side seal oil pump receives its supply from the hydrogen side seal oil float chamber. It pumps part of this oil through a seal oil cooler to the hydrogen side of the gland seal rings.

The seal oil backup from the main bearing oil feed system is normally closed. If the motor driven air side seal oil pump should stop, or if the seal oil pressure at the seals should decrease to 8 psi above the hydrogen pressure, the backup regulator valve will open automatically and provide oil pressure for the seals.

The main oil pump on the turbine shaft is the primary source of seal oil backup at all times when the turbine is operating between 2/3 speed and full speed.

In order to provide adequate seal oil backup pressure, an A-C seal oil backup pump on the main oil reservoir is provided to start at the same time as the auxiliary bearing oil pump. Thus, an adequate source of seal oil backup is always available from the

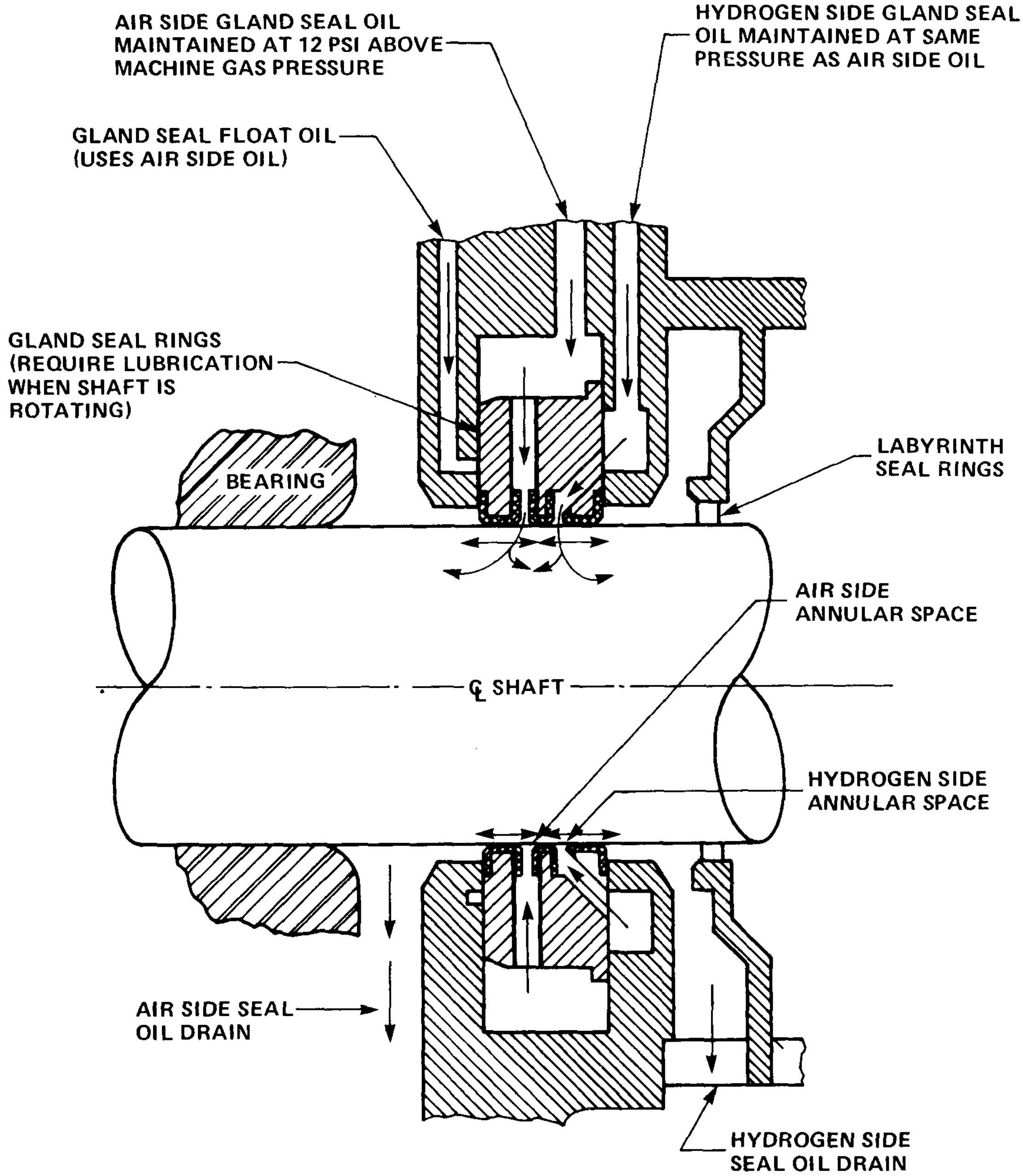


DIAGRAM OF GLAND SEAL
Figure 2.7-3

turbine oil reservoir, regardless of the turbine speed. A last source of seal oil backup from the oil reservoir, at relatively low pressure, is provided by turning gear oil pumps.

It should be borne in mind that the amount of gas pressure that can be maintained in the generator depends not upon the pressure being developed by the source of seal oil pressure then operating, but rather depends upon the pressure available from the next backup source of seal oil pressure.

The generator may be operated hydrogen cooled with air side seal oil supplied by the seal oil backup system with no increase in hydrogen consumption. The generator may also be operated hydrogen cooled if the hydrogen side seal oil pump is not operating. Under this condition of operation, seal oil from the air side feed groove will flow in both directions along the shaft, providing the necessary lubrication and preventing the hydrogen from escaping from the generator. It will be necessary however to add fresh hydrogen to maintain the required value of hydrogen purity in the generator, since the air side oil flowing into the hydrogen side of the seal rings will bring air and moisture into contact with the hydrogen inside the machine and will remove some of the hydrogen from the generator by absorption into the oil.

2.8 CHEMICAL FEED SYSTEM

2.8.1 High Pressure Steam Cycle Operating Conditions

The HRSG employed in this plant operates at high pressures and temperatures. Therefore, the steam cycle and condensate return system is subjected to the same critical operating conditions as a conventionally fired high pressure drum boiler installation. Requirements for the protection of internal surfaces, system cleanliness, and feedwater purity are stringent. Of fundamental importance is the prevention of solids deposition on heat exchange surfaces, in restricted passages and on turbine blades. Essential to the overall protection of the system is the control of boiler water chemistry and solids concentrations by the implementation of a suitable internal water treatment program and boiler water blowdown procedure.

DEPOSITION AND EROSION:

System makeup water is delivered to the HRSG feedwater system from a demineralizer installed in the balance of plant. Although of high purity, trace amounts of dissolved solids are present and tend to concentrate in the boiler water during the evaporative process. If concentrations of solids become excessive, precipitation of the more common calcium and magnesium salts occur and to a lesser degree the more complex type of salt, such as sodium silicate. Also, at the higher operating temperatures and concentrations, silica and sodium tend to vaporize or become soluble in steam, and can be carried over by the steam leaving the boiler drum.

Sludge and scale deposits on the internal walls of evaporator tubes and steam drums are caused by the accumulation of precipitated make-up solids in the boiler water and from elemental iron and metalic oxides (crud) carried over in the feedwater from the condensate return system.

In normal operation, because of the high purity of the feedwater, deposited material is largely composed of crud carried over in the feedwater. However, during periods of abnormal operation, for instance, the occurrence of a condenser tube sheet leak or malfunction of the demineralizer, the relative composition and rate of deposit of solids is drastically changed by the increase of solids in the feedwater. Solids deposition on evaporator tubes impedes heat transfer with a resultant loss of thermal efficiency; but more importantly, causes overheating and eventual failure of the tubes. Silica deposits on IP and LP steam turbine blades results in reduced turbine efficiency and if severe enough, forced outage of the turbine. Similarly, the impingement and deposit of entrained sodium salts on HP turbine blades and passageways can cause severe restriction to flow and turbine damage. A pre-requisite for the control of solids concentration, surface deposits and carryover of entrained solids, is the installation of an adequate steam drum blowdown system.

CORROSION:

Oxygen is normally present to some extent in the demineralizer makeup water to the condenser hotwell. Both oxygen and carbon dioxide can enter the condensate system through air in leakage at the condenser. Carbon dioxide is also formed insitu by the decomposition of bicarbonate and carbonate alkalinity in the boiler water. With proper control of water chemistry and solids concentrations, this occurrence can be avoided. Dissolved oxygen and carbon dioxide, aside from localized cell action, are the principle causes of corrosion in steam and condensate lines.

2.8.2 Boiler Water Control

Proper protection of the HRSG systems requires that boiler and feedwater composition and solids concentrations be maintained within safe operating limits under all conditions of service. In order to accomplish this, boiler blowdown and internal chemical treatment programs are necessary. The following water quality limits will be used in the design of these programs.

DEMINERALIZER EFFLUENT

Constituent	Concentration (ppm)
Total Ionizable Solids	< 0.2
Total Hardness	0 - .01
Carbon Dioxide	0
Iron	0
Silica	<.01
Turbidity	0 - 1 (T.U.)
pH	6.5 - 7.5

FEEDWATER QUALITY - NORMAL OPERATION - ECONOMIZER INLET

Constituent	Concentration (ppb)
Total Solids	50 max.
Total Iron	10 max.
Total Copper	10 max.
Total Silica	20 max.
Oxygen	5 max.
Hydrazine	10 - 20 max. residual
pH	9.2 - 9.4

2.8.3 Chemical Feed Program

The following water quality limits are consistent with current technology and accepted operating practices for high-pressure drum boiler steam cycles. In the event that a system abnormality occurs, such as a condenser leak, limited operation under controlled conditions is possible providing total solids in the feedwater does not exceed 2.0 ppm.

A suitable amine will be injected into the condensate system at chosen locations for feedwater, pH adjustment. Hydrazine is also injected into the feedwater for oxygen scavenging purposes. Primary injection points for amine and hydrazine are provided in the common section of the condensate return piping, upstream of the gland steam

BOILER WATER CONTROL - NORMAL OPERATION

Feedwater Conditions	Drum Water Using Phosphate Treatment
Total Solids <0.5 ppm	Total Solids-50 ppm pH 9.4 - 9.7 PO_4 5 - 10 ppm

BOILER WATER CONTROL - ABNORMAL OPERATION - EMERGENCY CHEMICAL TREATMENT

Feedwater Conditions	Drum Water Using Phosphate Treatment
Total Solids 0.5 - 2.0 ppm (Limited Operation) Total Solids >2.0 ppm (Emergency Operation)	Total Solids 100 ppm pH 9.5 - 10.5 PO_4 5 - 20 ppm

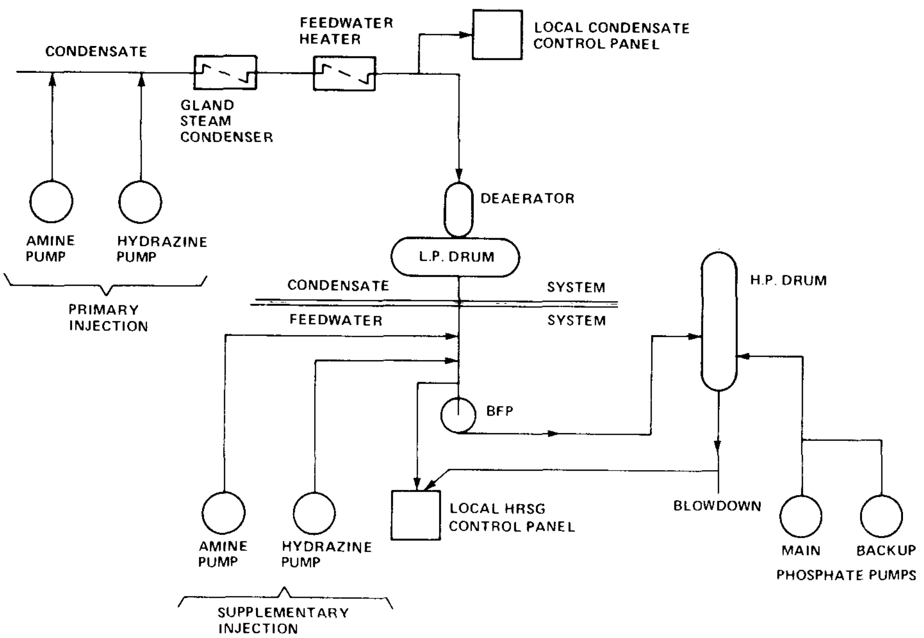
condenser. Supplementary injection points for both chemicals are located in the boiler feedpump suction line of each HRSG unit.

This plant will utilize internal phosphate treatment during normal operation, with the solution injected directly into the HRSG drum water. Feed rates must be established to maintain PO_4 and pH values, such that no free hydroxide exists in the boiler water. Pump injection and sampling points of the chemical feed system are given in Figure 2.8-1.

2.8.4 Chemical Feed And Water Sampling Equipment

Automatically controlled hydrazine and amine chemical feed systems will be furnished for primary injection of chemicals at the gland steam condenser location. Each set of equipment includes a solution tank, necessary piping and two metering pumps equipped with manual-automatic electric stroke positioners operated by a two-point analog control system located in the water quality panel. Pumps will be rotated in service.

Manually controlled hydrazine and amine chemical feed systems will be furnished for supplementary injection of chemicals at each boiler feed pump location. The equipment will be individually located at each unit. Each set of equipment includes a solution tank, necessary piping and one metering pump equipped with remote manual electric stroke positioner. Pump operation will be controlled manually at the pump or remote manually from the water quality sampling room.



POWER BLOCK CHEMICAL FEED SYSTEM
Figure 2.8-1

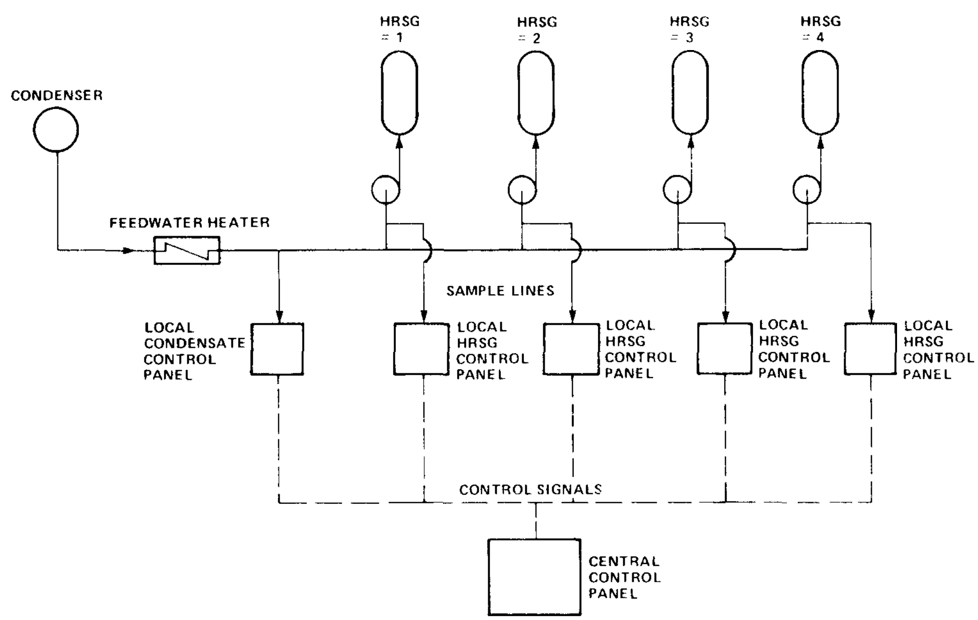
Separate phosphate feed systems will be furnished for each HRSG unit and installed adjacent to the supplementary hydrazine and amine feed equipment. The phosphate feed equipment includes a solution tank, mixer, dissolving basket, necessary piping, and two metering pumps equipped with remote manual electric stroke positioner. Pump operation will be controlled manually at the pump or remote manually from the water quality sampling room.

Water quality control panels will be provided for each HRSG and for the condensate return. Sample coolers, pressure regulators, valves, tubing, sink and other parts comprising the sampling system, will be installed in one section of the control panel. All analytical testing apparatus, accessory instrumentation, electrical component, wiring and all face-mounted instrumentation and pump controls will be installed in the remaining section of the panel. Minimum readout instrumentation will be on each local panel to permit manual pump operation. Each panel will contain "remote" operation switches for each pump to permit remote manual operation from the central water sampling room included as part of the balance of plant design. Sample coolers, grab sample valves, pressure reducing capillaries and block valves for high pressure boiler water and steam sampling will also be included as part of the local HRSG panels.

The local control panels will contain sensing and analytical instrumentation, wired to a terminal board that will permit readout and control signals to be directly wired to the central control panel located in the plant water sampling room. This is displayed by Figure 2.8-2. Readout instrumentation at the remote central panel will include:

- Conductivity analyzer recorders.
- pH analyzer recorder.
- Hydrazine analyzer recorder.
- Automatic sampling programmers for conductivity, pH, and hydrazine residual sample switching.

Monitoring points and tube runs for sampling will be provided in accordance with Table 2.8-1.



WATER QUALITY CONTROL PANEL ARRANGEMENT
Figure 2.8-2

TABLE 2.8-1
SAMPLING PROGRAM

Measurement	Source	Collection	Purpose
Conductivity	Blowdown	(A) (G)	Total Solids and Blow-down Rate.
Conductivity	Condensate Pump Disch.	(A) (G)	Condenser leak detection.
pH	Blowdown	(M) (G)	Blowdown and PO_4 Control.
Na, SiO_2, PO_4, TS	Blowdown	(G)	Check TS/Conduct. Ratio & Estab. Upper Na, SiO_2 Levels.
Conductivity	Demineralizer Makeup	(A) (G)	PO_4 control. Early breakthrough signal.
Na	Cond. Pump Disch.	(G)	Condenser leak detection.
Hydrazine Residual	Feedwater Heater Outlet	(A)	Auto. Hydrazine Feed Setting.
Hydrazine Residual	Economizer Inlet (BFP Suction)	(A)	Adjust Hydrazine Feed Setting.
pH	Feedwater Heater Outlet	(A)	Auto. Amine Feed Control.
pH	Economizer Inlet (BFP Suction)	(M)	Adjust Amine Feed Settings.
Condensate Flow	Flow meter analog signal	(A)	Auto. Hydrazine & Amine Feed Setting.
Oxygen	Boiler Feed Pump Suct.	(G)	Check on O_2 resid. at deaerator
Silica and Sodium	Drum Steam	(G)	Check on carryover.
(A) Automatic Sampling (M) Manual Switching of Sample to Instrument. (G) Grab sample for laboratory analysis.			

SECTION 3
OPERATION AND STARTUP

3.1 PART-LOAD PERFORMANCE

Part-load operation of the coal gas combined cycle power plant is discussed in general terms at this time, since part-load operation of some of the major components such as the gasifier and gas cleanup systems is not analyzed in depth as part of Phase I of the program. It is possible, however, to discuss in a broad sense the trends that will be encountered during part-load operation. In this discussion of part-load performance, two distinct modes will be addressed:

(1) Performance at design ambient conditions; reduced load.

(2) Performance at off-design ambient conditions; full load.

3.1.1 Performance At Design Ambient Conditions, Reduced Load

Since the heat recovery steam generators are not equipped with supplementary burners, a change in load will be related directly to the combustion turbine status. At a given set of ambient conditions, there are two ways to reduce the combustion turbine load:

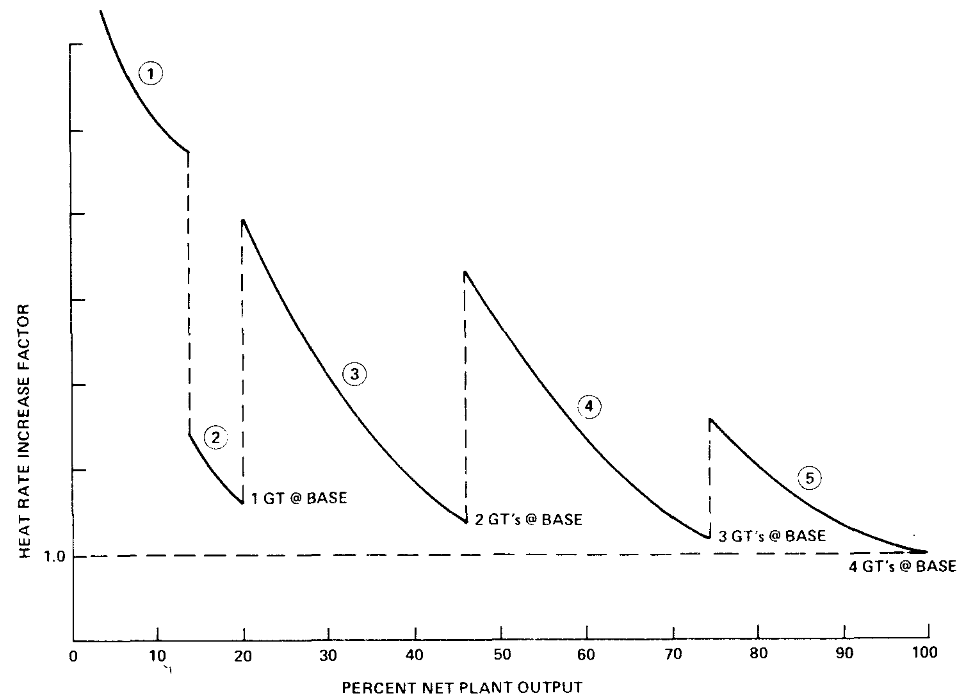
(1) Modulation of the inlet guide vanes;

(2) Reduction of turbine inlet temperature.

It is advantageous to maintain turbine inlet temperature and steam temperature as long as possible so modulation of the compressor inlet guide vanes occurs as the first step in reducing load. The gradual closing of the inlet guide vanes reduces compressor air flow, compressor discharge temperature and discharge pressure.

Fuel is adjusted to maintain base load turbine inlet temperature but due to the reduced pressure ratio, exhaust gas temperature is increased slightly. The gradual increase in exhaust temperature continues until the guide vanes reach minimum closure. At this point, further load reduction is accomplished by decreasing the turbine inlet temperature.

Figure 3.1-1 shows the trends in performance for the coal-gas combined cycle plant made up of four combustion turbines, four heat recovery steam generators, and one



HIGH-TEMPERATURE TURBINE COMBINED CYCLE OPERATING ON COAL GAS
Figure 3.1-1

large reheat steam turbine. Segment 5 of the curve shows the trends in power reduction from 100% and heat rate increase from normal as all four combustion turbines undergo compressor inlet guide vane modulation and possibly turbine inlet temperature reduction. When three quarters capacity is reached, one combustion turbine can be shut down while the remaining three increase in capacity back to base load. Similar events occur for segments 4, 3 and 2 as the number of combustion turbines shutting down progresses. Segment 2, however, is affected by the steam turbine going off the line at its minimum power. At this point, the remaining combustion turbine generates the load as represented in segment 1.

The shape and slope of the curve segments and their relationship to one another will be affected by a variety of factors. Whether the incremental load points can be achieved by merely closing the combustion turbine inlet guide vanes remains to be determined since interaction of the combustion turbine and gasifier capabilities will have a direct influence on the plant method of load reduction. The behavior of the gasifier system with regards to pressures, temperatures and flows at part loads and how these parameters match the requirements of the combustion turbine will require indepth analysis in a later phase of the program.

In addition, the required operational characteristic of the heat recovery steam generators and the steam turbine will require close scrutiny. At some operating points, it may be necessary or advantageous to allow the turbine to float on the line; that is, with the steam turbine throttle valves wide open. In this mode, the turbine stator and rotor flow areas become the flow orifice for the system. The cumulative, "effective", area of the turbine plus the frictional losses in the piping will determine the HRSG drum pressures. At some other operating point, it may be necessary or advantageous to operate the system "up to pressure". In this mode, drum pressures are maintained at design values by closing off some of the turbine nozzle area, thus reducing the effective area of the system. The determination of when to operate "valves-wide-open" and when to operate "up-to-pressure" must be integrated with the other plant components and their part-load characteristics.

3.1.2 Performance At Off-Design Ambient Conditions, Full Load

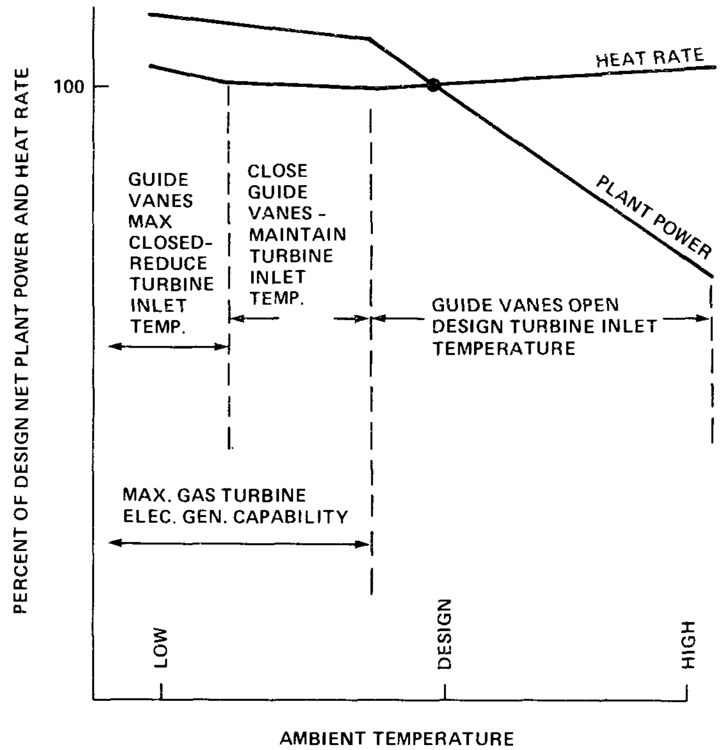
The variation in performance at off-design ambient conditions will be addressed in two ways:

(1) Vary ambient temperature while maintaining constant barometric pressure;

(2) Vary barometric pressure while maintaining constant ambient temperature.

AMBIENT TEMPERATURE VARIATION:

As ambient temperature varies, the combustion turbine pressures, temperatures and flows will vary. The compressor discharge pressure will dictate the required gasifier pressure while the turbine exhaust temperature will influence the steam temperature in the HRSG. At higher ambient temperatures, the exhaust gas flow is below design while the exhaust temperature is above design. At the lower ambient temperature, the turbine exhaust temperature reduces and the exhaust gas flow increases. Therefore, if the superheater and evaporator surfaces are designed to meet the steam requirements at a given set of conditions, the steam temperature will tend to increase at the higher ambient temperatures. The design steam temperature can be maintained by attemperation. Attemperation in the HRSG is achieved by utilizing a superheater bypass valve which regulates the steam temperature without the use of a desuperheating spray. By merely bypassing a portion of the evaporator steam around the superheater, the steam temperature to the turbine can be controlled without the potential of water damage. Two factors will affect the steam temperature at low ambient temperature: (1) The gas turbine will reach the maximum capability of its electric generator at some point which will necessitate either a reduction in flow by modulating the compressor inlet guide vanes or a reduction in turbine inlet temperature; and (2) the gas turbine exhaust temperature will diminish and may reach a point where steam temperature cannot be maintained. The former is the more likely to occur as ambient temperature diminishes. Since turbine inlet temperature can be maintained by modulating the guide vanes and since this results in maintaining exhaust temperature, the initial adjustments to output should be made in this manner. If at some low ambient temperature the generator capability will be exceeded even at minimum guide vane setting, then the turbine inlet temperature must be reduced. This limit most likely will occur at temperatures lower than minus 20°F (-29°C). Figure 3.1-2 displays the general trends in performance



AMBIENT TEMPERATURE EFFECT ON PLANT PERFORMANCE
Figure 3.1-2

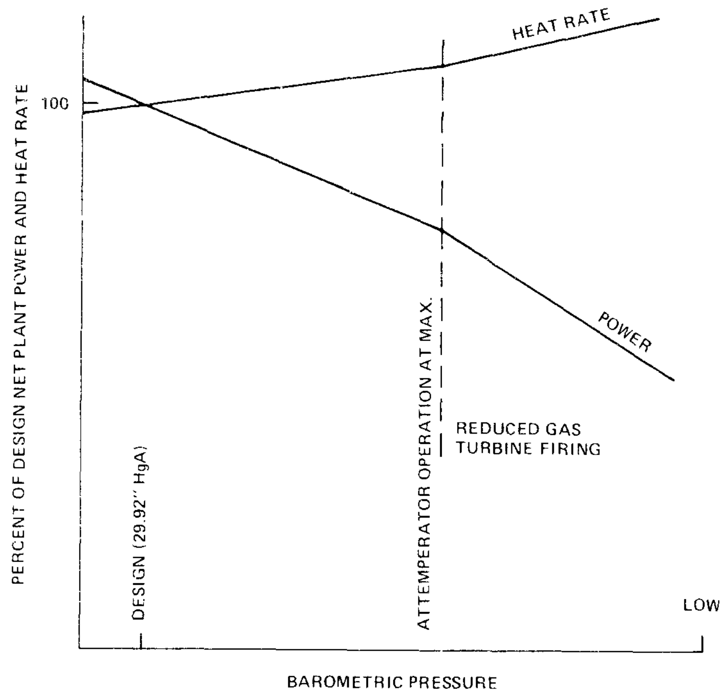
as ambient temperature varies. Although this discussion has centered on ambient temperature, the gas turbine performance is actually sensitive to compressor inlet temperature. For all intents, they are identical except in those instances where evaporative cooling or supercharging is used. In this discussion, ambient temperature and compressor inlet temperature are assumed equal.

BAROMETRIC PRESSURE VARIATION:

If ambient temperature is maintained and barometric pressure is lowered, the plant output reduces and the heat rate increases. Since barometric pressure is related directly to the density of air entering the compressor, the combustion turbine output will vary in a similar way. The combustion turbine heat rate, however, will remain essentially constant, along with its exhaust temperature. Therefore, as barometric pressure diminishes, the flow through the HRSG diminishes but the gas temperature entering the HRSG does not. This results in lower steam flow with the accompanying reduction in steam turbine output. Eventually, as barometric pressure reduces further, a point will be reached wherein the desuperheating devices cannot attemperate the superheat and reheat steam sufficiently*. At this point, the combustion turbine firing

*There is also a limit on other auxiliary equipment such as air-to-air coolers, motors and the like where a change in equipment may be required. For example, if a plant were constructed on a site of very high elevation — say 10,000 feet, the normal barometric pressure would be about 21" of Mercury absolute. In this type of environment, some major changes to equipment may be required.

must be reduced in order to lower the temperature entering the HRSG which in turn will allow the attemperating devices to control steam temperature. Plant heat rate and power will exhibit characteristics as shown on Figure 3.1-3.



BAROMETRIC PRESSURE EFFECT ON NET PLANT PERFORMANCE
Figure 3.1-3

SECTION 4
GASIFICATION SYSTEM

The Reference Design of the Gasification System describes and summarizes the type of units and equipment chosen from those parameters and alternatives discussed in the OPDD Low-Btu Combined Cycle Electric Power Plant Report. The process may be followed by reference to flow sheets Figures 4.0-1, 4.0-2, 4.0-3 and 4.0-4.

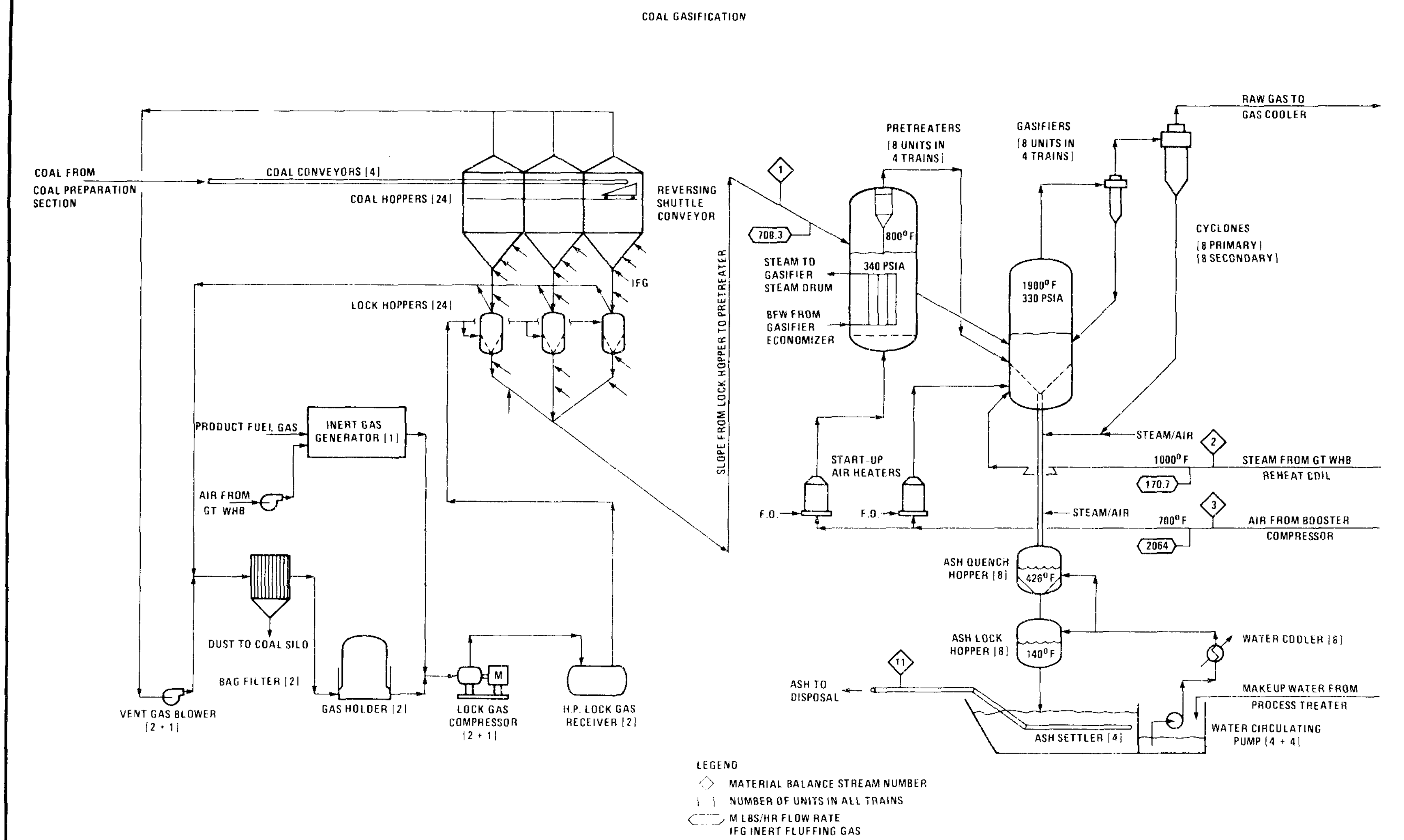
4.1 COAL INJECTION

A lockhopper type of coal injection system was chosen as described in the OPDD Low-Btu Combined Cycle Electrical Power Plant Report Section 4.1. This consists of three (3) coal storage bins elevated above three (3) lockhoppers for each pretreater-gasifier reactor. The three (3) storage bins hold a total of four (4) hours of coal inventory. The lockhoppers operate on a thirty-minute cycle; thus, there is one (1) lockhopper emptying into the pretreater every ten minutes.

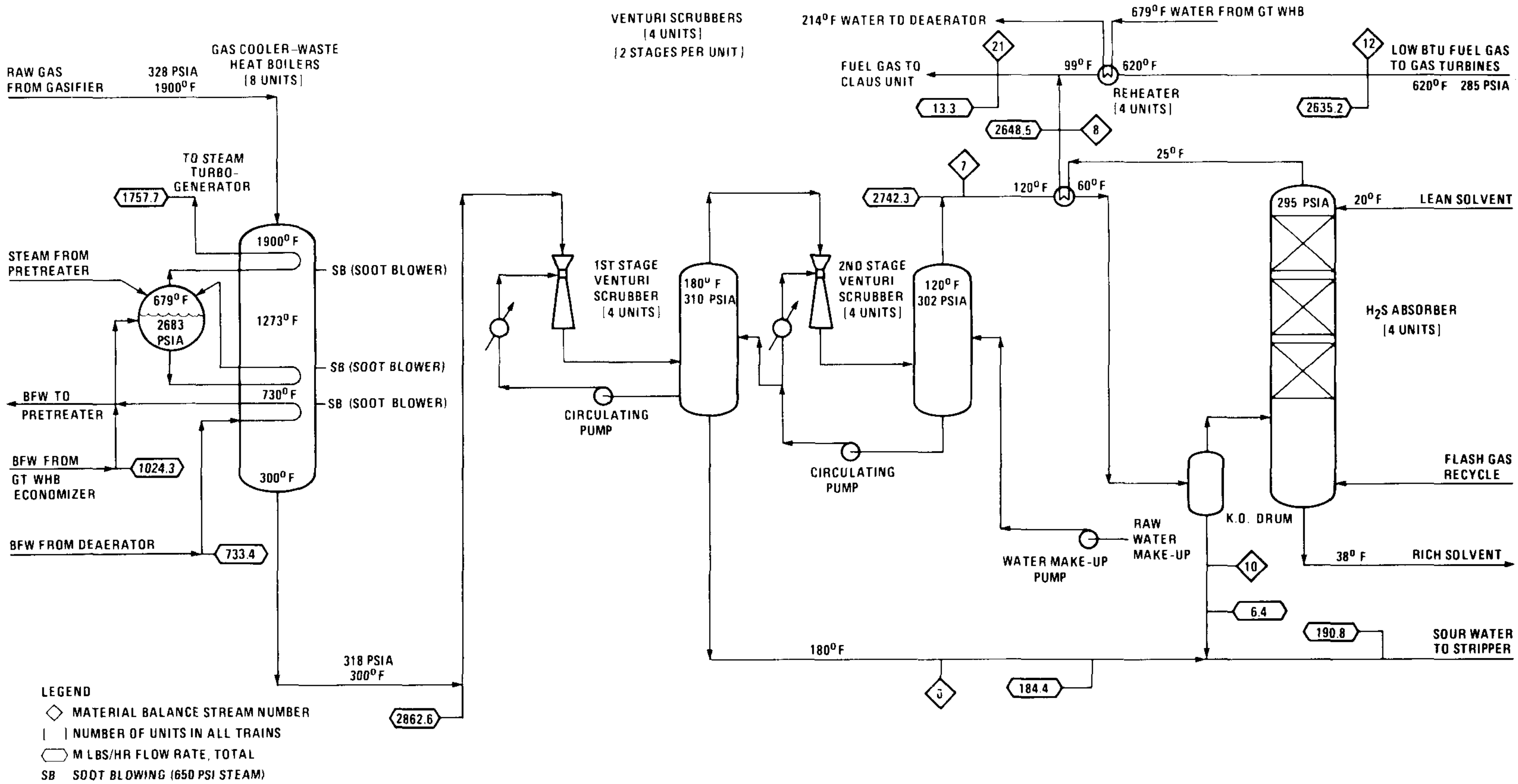
The coal bins are each 15 feet by 15 feet by 10 feet high with a conical bottom having a 60° angle. Each bin has an activator to ensure coal flow as well as an inert gas flow to ensure that the 0 x 1/4" size coal will be fluffed for easy flow of the coal. Each lockhopper will be 6'6" in diameter by 13' high with dual automatic ball valves on coal discharge and entry lines. The use of three lockhoppers saves on the energy required to recompress the lock gas. Lock-gas makeup is derived from the inert gas generator. The lock-gas compressor is a three- (3) stage reciprocating compressor with inter- and after-cooling. Lock-gas is compressed from atmospheric pressure to 350 psia for injection into the lockhopper. The lockhopper does not require pressuring from atmospheric pressure as in a three- (3) hopper system; the first pressuring occurs from equalizing with a high-pressure hopper which first raises the pressure to 212 psia, then the compressor raises the pressure to 350 psia. In depressuring the high-pressure lockhopper, first it is equalized with a low-pressure hopper, then the gas is let down to atmospheric pressure through a bag filter to a telescoping gas holder from which the compressor takes suction.

4.2 COAL GASIFICATION

The coal gasification section consists of a fluidized bed pretreater operating at $750^{\circ}F$ to $800^{\circ}F$. The coal is heated by combustion with air and excess heat is removed via cooling coils immersed in the fluidized bed. Each gas turbine will require two pretreaters and two gasifiers. The pretreaters are 7'0" inside diameter by 40 feet high. The gasifier is 12'6" inside diameter by 45 feet high.

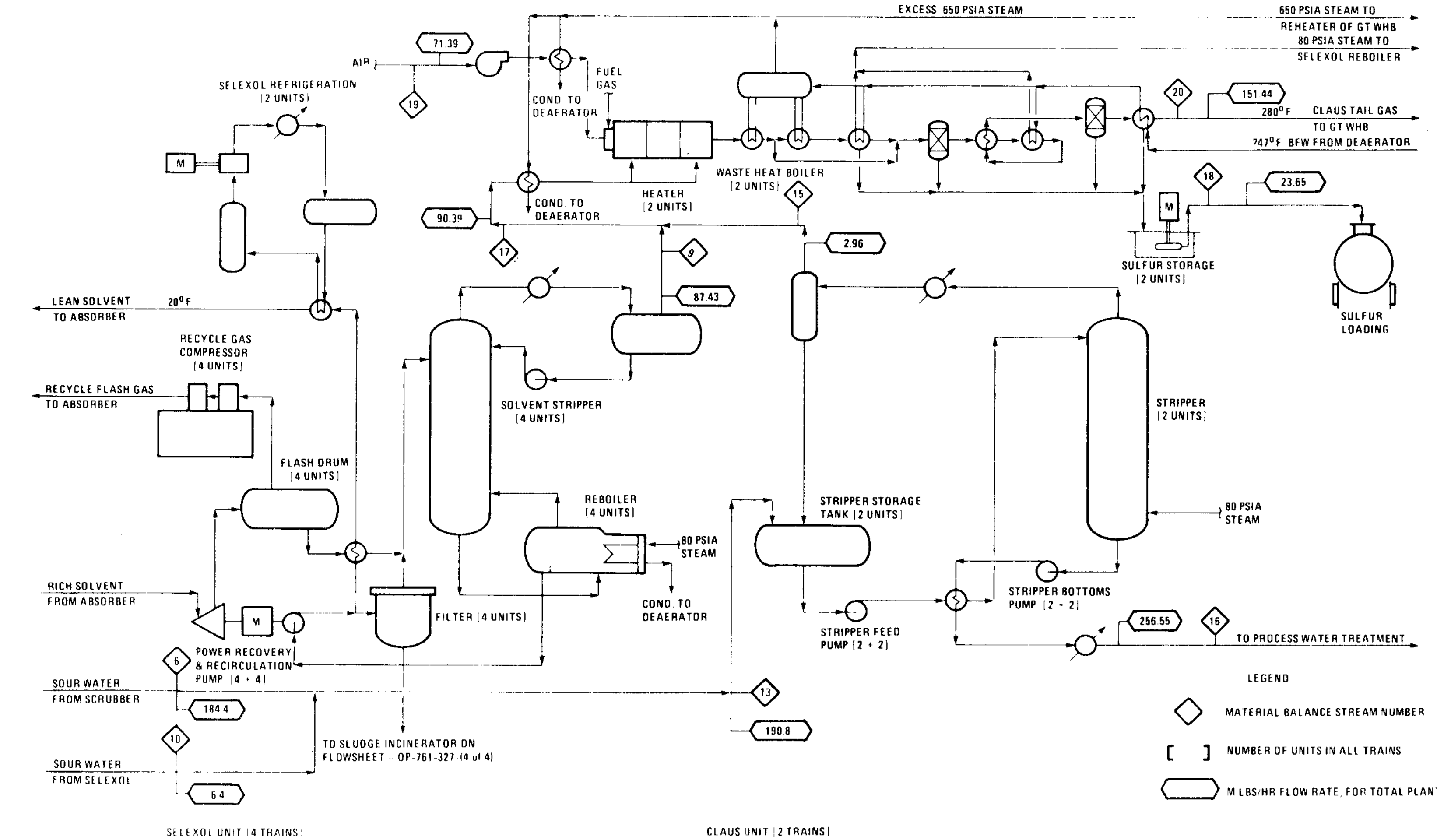


COAL GASIFICATION FLOW DIAGRAM
Figure 4.0-1

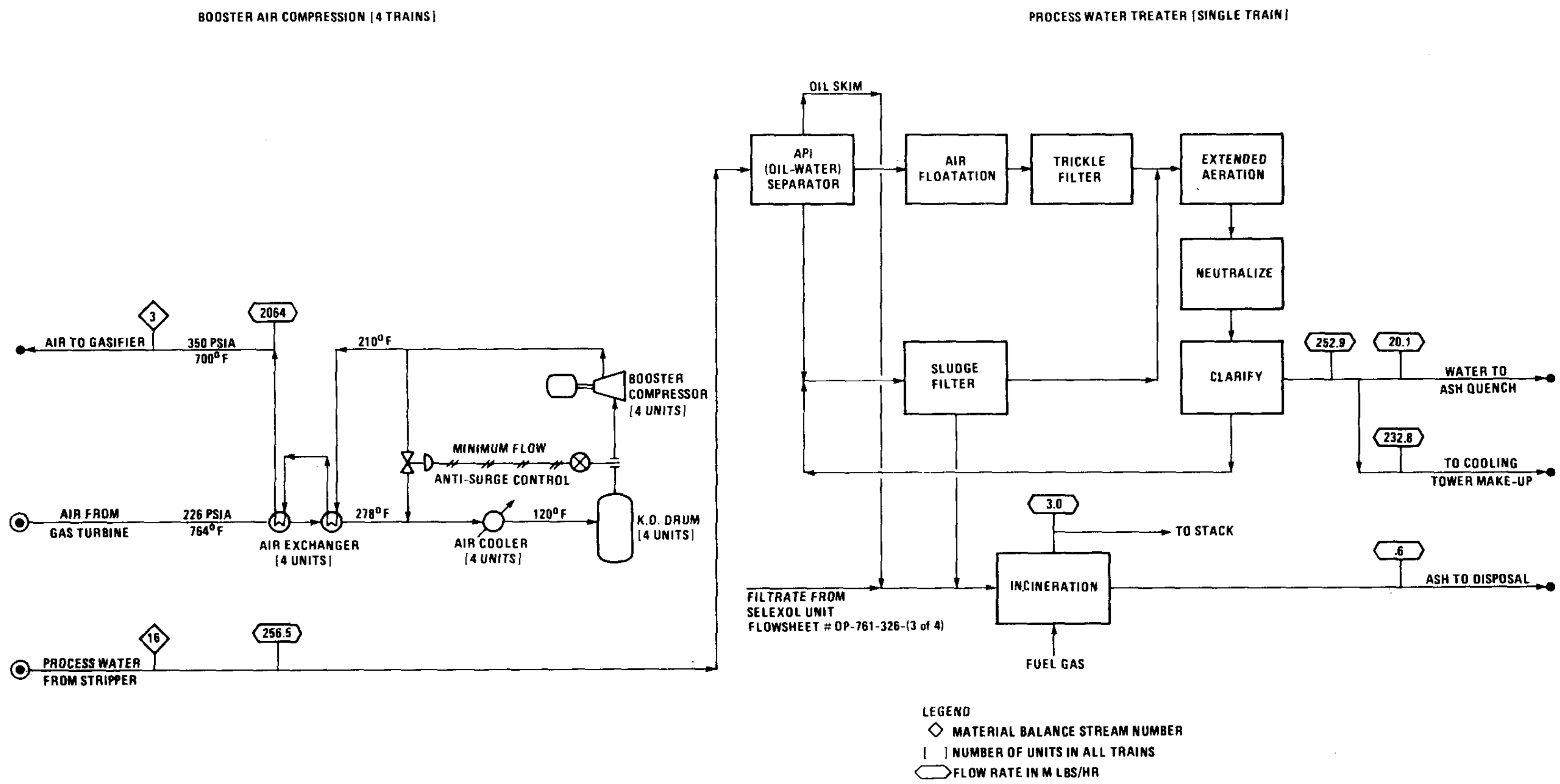


COAL GASIFICATION CLEANUP FLOW DIAGRAM

Figure 4.0-2



SELEXOL AND CLAUS FLOW DIAGRAM
Figure 4.0-3



BOOSTER COMPRESSOR AND PROCESS WATER TREATER FLOW DIAGRAM
Figure 4.0-4

The gasifier operates as a fluidized bed at 1900°F. The lower section contains a conical grid to support the fluidized bed. A high concentration of air in the center of the grid cone creates a localized high temperature causing agglomeration of the ash particles. The ash falls down the central pipe and is quenched in an ash hopper. The quenched ash is periodically removed from the ash quench hopper by dropping into an ash lock hopper and from the lock hopper ash drops into the ash pit. Ash is collected from ash slurry pits by means of conveyors and removed from the gasifier area.

Fines are partially removed from the top of the gasifier by means of two (2) stages of cyclones. The fines are returned to the fluidized bed from the first cyclone stage and the fines from the second stage are returned to the agglomeration section of the gasifier.

4.3 PROCESS WASTE HEAT BOILER

Hot gas with a small amount of dust from the gasifier at 1900°F is cooled to 300°F in the Process Waste Heat Boiler. There is one heat recovery unit for each gasifier, or two boilers for each gas turbine, for a total of eight (8) process waste heat boilers for the entire plant. The heat recovery unit preheats boiler feed water in an economizer section, evaporates at 679°F and 2683 psia, and superheats steam at 1000°F and 2495 psia. Each process WHB is 11'0" inside diameter by 36' high. The shell of the vessel will be internally refractory lined with about 1-foot thickness of insulation and refractory. The steel shell will also be lined with stainless steel to prevent corrosion by vapors condensed behind the refractory. Soot blowers are provided to keep the surface free of ash.

4.4 WATER SCRUBBING

Two stages of venturi scrubbers are provided to remove the last traces of particles, and also to cool the gases from 300°F to 120°F. The pressure drop per stage is eight psi in order to allow a high velocity in the venturi. The separators after the venturis are 12'0" inside diameter by 20 feet high. Fresh water is introduced into the second-stage scrubber to ensure clean gas. The water from the second stage at 120°F, together with condensed water and a small amount of solids, is introduced into the first-stage scrubber. In the first-stage scrubber, additional water is condensed from water vapor in the gas stream together with more solids. The water from the first-stage scrubber at 180°F is withdrawn from the system and sent to the sour water stripper.

4.5 GAS PURIFICATION

Gas at 120^oF from the previous scrubbing section is sent to the gas purification section to remove sulfur compounds in gas. A Selexol system, licensed by Allied Chemical Corporation, is used to absorb most of the H_2S and COS in the acid gas. Selexol uses polyethylene glycol dimethyl ether as a solvent. The Selexol system consists (for each of four trains) of an absorber of 12'0'' inside diameter by 110' high, and a solvent stripper 8'0'' inside diameter by 110' high. Both towers are packed with 2'' pall rings. The gas entering the absorber is first cooled in a gas-to-gas heat exchanger, and the absorber operates at a low temperature obtained by chilling the lean solvent to 20^oF. Rich solvent from the bottom of the absorber is flashed in a power recovery turbine, and flashed gas is returned to the absorber via a small compressor. The stripper uses closed, low-pressure steam and reflux is sent back to the top of the stripper. Excess water is withdrawn from the solvent to maintain a constant water inventory in the solvent.

The Gas Purification System was designed to remove sulfur down to 200 ppm by volume in the fuel gas. This is lower than the pollution requirements, but is a low enough concentration of sulfur in the fuel gas to ensure no harm to the metallurgy of the gas turbine and its heat recovery unit. The SO_2 discharged from the gas turbine heat recovery unit is 0.18 lbs. SO_2 per million Btu of coal.

4.6 SULFUR PRODUCTION

Acid gases from the Selexol unit are sent to a modified Claus unit to produce elemental sulfur. The Claus unit design and operation are modified to minimize formation of COS and to dissociate the NH_3 to elemental nitrogen and water. The modified Claus unit requires a small amount of product fuel gas to be burnt with the H_2S in order to ensure a temperature profile favorable to the destruction of ammonia. The Claus unit also is fed with the small amount of acid gas derived from the sour water stripper.

The tail gas from the Claus unit can be further treated, producing more sulfur, in a Bevon or Scot type unit, or it can be incinerated or added to the gas turbine effluent which is above 1200^oF for incineration and heat recovery in the gas turbine heat recovery unit. The tail gas is sparged into an expansion in the gas turbine exhaust line in a manner which will ensure good mixing.

The Claus unit tail gas when incinerated contains 0.66 lbs. SO_2 per million Btu of coal; the turbine fuel gas contains 0.18 lbs. SO_2, for a total of 0.84 lbs. of SO_2 per million Btu of coal, which is well below the pollution restriction of 1.2 lbs. SO_2 per million Btu coal.

A two-reactor system with bypass reheat is provided, producing a total of 236.5 long tons per day divided into two trains for ease of turndown. The Claus unit produces 650 psia and 80 psia steam. A small amount of steam is used internally for preheating and steam tracing, the remainder is exported.

4.7 AMMONIA AND SOUR WATER STRIPPING

Sour water from both the scrubber section and the Selexol section must be stripped of acid gases and of ammonia before disposal of the water. About 23,000 GPH of sour water is to be stripped with 68,757 lbs/hr of low-pressure steam. A single train tower is sufficient with a 6'0" inside diameter containing 38 stripping trays plus two wash trays for a total of 90' high. The trays will be alloy valve type trays. The ammonia and acid gas are sent to the Claus unit and the stripped water is sent to the water-treating plant. Possible ammonia recovery will be assessed in Phase II.

4.8 PROCESS WATER PURIFICATION

The design of Process Waste Water treatment is based upon the possibility that some organics may contaminate the waste water. These must be removed along with any particulate from the scrubbers before the water can be released to the cooling tower or to the river.

The waste water treatment plant consists of a gravity settler where floatable oil and settleable solids are removed from process water as well as from rain and wash-down water. The water flows to an air flotation unit where small droplets of oil and finely divided solids are removed. From air flotation, the water goes to a trickle filter to remove gross quantities of phenolics and then the water is sent to an extended aeration unit where biological sludge converts the organics and produces water acceptable for discharge. From the extended aeration the water is sent to clarifiers to remove the microorganisms; the water then flows to cooling tower makeup. Sludge and oil are dewatered in a filter-thickener and sent to incineration. Incineration ash is sent to the ash conveyor for disposal.

4.9 AIR BOOSTER COMPRESSOR

The gas turbine air compressor produces air at 218 psia and 731.1°F. About one-fifth of this air is used in the gasifier to produce low-Btu fuel gas. The air from the gas turbine is cooled, compressed and reheated so that air enters the gasifier at 700°F and 350 psia. Air from the gas turbine is exchanged with the booster compressor discharge air; it is cooled to 120°F and compressed from 208 psia to 358 psia. After compression, the air is reheated to 700°F in the Feed-Discharge air exchanger.

4.10 SULFUR STORAGE AND LOADING

Molten sulfur from the Claus plants will be stored in two pits adjacent to the two Claus plants. Total storage will be five days of production. The pits will be covered and filled with steam coils to hold the molten sulfur at about 280°F. Vertical sump pumps in the sulfur pits will intermittently pump the liquid sulfur to rail tank cars or to tank trucks for sale of the molten sulfur.

4.11 FUEL GAS REHEAT

Fuel gas leaves the Selexol unit at 99^{o}F. If the gas is heated to a higher temperature, the combined cycle power plant efficiency will be increased. In this phase, the fuel gas is heated to 620^{o}F with hot water from the gas turbine heat recovery unit. Water at 679^{o}F and 2683 psia is sent to the reheat exchanger where it is cooled to 246^{o}F. The water flows in the tube side to contain the high pressure. The fuel gas flows in the shell side. The shell side of the tube contains longitudinal fins to increase surface on the air side due to the low heat transfer rate of air.

SECTION 5
POWER BLOCK

5.1 COMBUSTION TURBINE, GENERATOR AND EXCITER

5.1.1 Combustion Turbine

The combustion turbine unit will be a single-case, single-shaft machine that will drive the generator from the compressor end of the shaft through a solid coupling. The total casing is divided into functional sections. These are identified as: inlet casing section, compressor and combustor section, turbine cylinder section and exhaust cylinder section. The casing design will include horizontal and vertical bolted joints to permit total or partial cover removal for internal inspection and maintenance.

5.1.1.1 INLET CASING SECTION

The inlet casing is fabricated from carbon steel plates and castings. It acts as a smooth boundary passage for the air flowing into the compressor and provides a housing for the thrust and journal bearings. The lower half of the bearing housing is integral with the casing but the thrust bearing cover is removable to permit inspection without disturbing the remainder of the casing. The thrust bearing will be of the double Kingsbury design and will axially locate the combined turbine generator shaft system. Thrust bearing shoes on both sides of the shaft thrust ring, as well as the loaded journal bearing pad are equipped with thermocouples for monitoring bearing temperatures as part of the supervisory instrumentation system.

5.1.1.2 COMPRESSOR AND COMBUSTOR SECTION

This section of the engine casing houses the stationary diaphragms of the axial flow compressor and accommodates the combustion chamber. It also incorporates bleed air manifolds and connections to facilitate air extraction from the engine for turbine cooling, for the gasification process and compressor unloading during startup. The cylinder rests on rigid pedestals, which form the compressor end support of the combustion turbine.

5.1.1.3 TURBINE CYLINDER SECTION

This cylinder provides the housing for the stationary turbine diaphragms, also referred to as the blade ring assemblies.

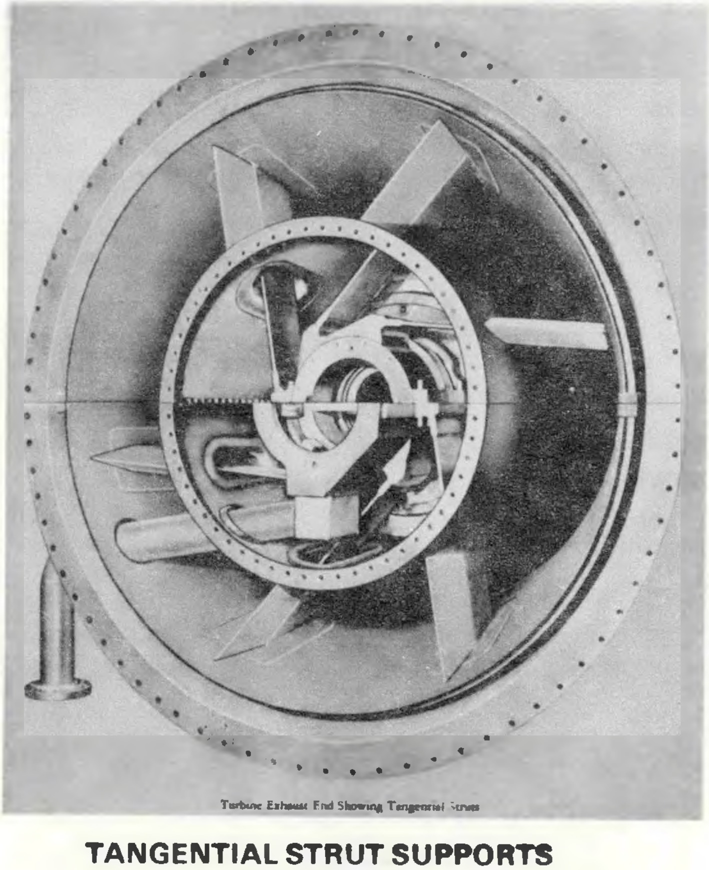
The combustion turbine trunnion support is part of this cylinder. Its purpose is to provide a rigid vertical restraint while allowing free axial and flexible lateral growth of the engine. A flexible rod at the bottom of the turbine cylinder supplements the trunnion support by allowing an axial and vertical growth of the cylinder while maintaining vertical centerline position.

5.1.1.4 EXHAUST CYLINDER SECTION

The exhaust cylinder contains the exhaust bearing housing and the exhaust diffuser, fabricated together by means of a strut system. The strut system will be the tangential design, a Westinghouse patented design in use since 1952. The system provides a low stress rigid support, which is capable of holding the bearing on center for all variations of load and temperature. Reference Figure 5.1-1.

5.1.1.5 SPINDLE ASSEMBLY

The combustion turbine rotor consists of compressor and turbine rotor subassemblies, bolted together to form one spindle assembly. The rotor is supported on two (2) pressure lubricated, pivoted-pad journal bearings.



TANGENTIAL STRUT SUPPORTS
Figure 5.1-1

5.1.2 Generator and Exciter

The generator driven by the combustion turbine is directly and solidly coupled to the turbine and has a rating of 146 MVA, 0.9 pf, 13.8 KV, 60 Hz. The rated hydrogen pressure is 30 psig. Rating, temperature rises and insulation class will be in accordance with the governing ANSI standards.

The main leads of the generator will be brought out the top of the generator shell through high-voltage bushings. Pre-wired current transformers are internally mounted on the main leads. The neutral connection will be made up internal to the generator and will include a neutral grounding transformer and grounding resistor. Each neutral lead will have pre-wired current transformers for metering and relaying.

Circuits requiring grounding are connected to the generator frame. Grounding pads on the generator frame provide for electrical connections to the external ground available at the installation site. The generator frame and the enclosing end brackets are fabricated from steel plate. The generator frame includes frame feet which are supported by the foundation.

Stator construction includes a stacked and wound core within a fabricated cage. This cage is isolated from the frame by support from several flexible steel springs. The flexible steel springs allow the cage to distort radially with considerable freedom, but support it rigidly in the direction of torque loads. This mounting system serves to eliminate double frequency vibration.

The stator core consists of laminations made of high-grade, low-loss silicon sheet steel. Each lamination, after it is deburred, is insulated with aluminum phosphate material which bonds to the metal in such a way that the insulation will not chip or wear with age. The laminations are properly located and locked into position by means of a patented notching process so that they cannot become dislodged. Insulated bolts are then passed through the laminations and drawn tight to ensure a permanently tight core and uniform air gap. The magnetic end plates and non-magnetic finger plates are used to provide an electrical shield to minimize stator end-region heating.

The stator winding has THERMALASTIC insulation. The impregnating resin used with this insulation will be the styrene modified epoxy.

Bracket type, self-aligning bearings support the rotor on the exciter and turbine ends. Bearing brackets are bolted solidly to the generator frame structure and are provided with stop-dowels in the bottom half for locating purposes. Vibration detectors monitor vibrations on each of the bearing supports. Thermocouples are supplied in bearing drains to monitor oil temperature. Bearings can be removed without removing hydrogen from the machine.

Hydrogen pressure is maintained at 30 psig by a regulator located in the hydrogen system cabinet mounted on the side of the generator. Continuous circulation is maintained by a shaft-mounted axial blower. The hydrogen is directed through the air gap and over the rotor and stator conductor and then through horizontally mounted coolers located within the generator frame. The hydrogen passes across a radiator type cooler, giving up its heat to the auxiliary cooling water provided from balance of plant. A temperature detector monitors the cold gas outlet of the cooler to ensure proper cooling of the generator.

The generator will be capable of withstanding, without injury, a 30-second, 3-phase short circuit at the terminals when operating at rated KW, rated power factor, and a 5 percent overvoltage with fixed excitation, provided the maximum phase current shall be limited by means of suitable reactance or resistance to a value which does not exceed the maximum phase current obtained from the 3-phase fault, in accordance with latest proposed ANSI standards. The generator will also be capable of withstanding without injury, any other short circuit at its terminals provided the machine phase currents under fault conditions are such that the negative phase sequence currents (I_2), expressed in terms of per-unit stator current at rated kVA and the duration of the fault in seconds (t), are limited to values which give an integrated product ($I_2{}^2t$) equal to, or less than 10. The generator will operate successfully at rated kVA, frequency and power factor and gas pressure at any voltage not more than five (5) percent above or below rated voltage.

The deviation factor of the open-circuit terminal voltage wave of the generator will not exceed ten (10) percent.

EXCITER

The brushless exciter is solidly coupled to the generator shaft and has sufficient strength to carry the torque developed by the starting device during startup to accelerate the turbine generator set to ignition and self-sustaining speed. A single-pedestal bearing supports the exciter shaft on the outboard end. The exciter is rated 400 KW at 250 volts, DC.

The regulator power source has permanent magnets located inside a steel ring attached to the shaft. The permanent magnet makes the set self sufficient, avoiding the necessity of an external source of power. The pilot exciter magnets are factory stabilized so that a short circuit on the pilot exciter armature or removal of the armature will not affect the magnetization level.

The core of the AC exciter is made of high-strength electrical sheet "donut" laminations mounted on the fluted shaft with a heavy interference fit. The shaft is a solid forging. Radial vents allow effective axial-radial ventilation. Rotor coils are shallow and special attention is given to consolidating the end turns. Glass polyester bands are used for this purpose.

The main components of the rotating rectifier are silicon diodes and indicating fuses. All rectifier components are mounted on the inside diameter of a high-strength steel retaining wheel. Each diode has an indicating fuse which can be observed while the generator is in service by use of a stroboscope light.

The diodes rectify the AC power generated by the AC exciter. The system is protected against diode failure by the series-connected fuses with indicating device. The indicating devices permit checking for open fuses by stroboscopic light while the exciter is operating. Two ground detection rings are provided for checking the condition of the insulation resistance to ground during operation. The circuitry is conservatively designed to permit operation of the unit, even when one fuse in each phase is open. In this mode of operation, there is no reduction in generator output power.

5.1.3 Auxiliary Packages

5.1.3.1 STARTING PACKAGE

The main starting motor will be a 2000 HP, 1800 rpm synchronous motor. The torque output of the motor will be increased by a hydraulic torque converter which has an output speed increasing gear to match the starting speed range (up to 2400 rpm) required of the turbine.

The hydraulic fluid of the torque converter is circulated by means of an external motor driven pump to the converter and then to a radiator cooler having a motor driven fan. This hydraulic circuit permits fluid cooling independent of converter operation as would be the case with shaft-driven auxiliaries. A shaft brake actuated by loss of hydraulic fluid pressure prevents starting shaft rotation due to clutch drag. The turning gear is a DC motor-driven double reduction gear unit, capable of developing the breakaway torque at startup and continuous shaft rotation at 2. 2 rpm for cooldown.

The starting clutch is a mechanical torque sensitive device that engages and disengages automatically and is engaged only when torque developed by the starting motor or turning gear is absorbed by the turbine.

5.1.3.2 MECHANICAL PACKAGE

The loop seal tank and main lube oil reservoir will be fabricated as part of the steel bedplate. The retention time or capacity of the reservoir will be a minimum of five (5) times the rated flow of the main oil pump. The reservoir will be fitted with an electric immersion heater to maintain a minimum 70^{o}F oil temperature for startup.

The main and backup lube oil pumps will be vertical centrifugal pumps flange mounted to the top of the oil reservoir, driven by AC motors. Since the main oil pump provides seal oil to the generator, its discharge pressure will be selected to maintain a pressure of 6 psi over the generator hydrogen at the seal after accounting for system pressure drops. This pressure will be controlled by the seal oil pressure regulator valve.

The emergency DC motor-driven lube oil pump will also be a vertical centrifugal pump, flange mounted atop the reservoir. This pump is sized to provide bearing and seal oil flow at a bearing pressure of approximately 6 psi.

The lube oil filter will have pleated paper cartridges capable of removing entrained foreign particles of five (5) microns or larger. The filter is arranged in the piping so as to permit a second filter to be added, and with the use of a switching valve, filter operation can be selected with the unit running.

5.1.3.3 FUEL PACKAGE

The valves used in the gas and oil fuel systems, with the exception of the throttle valves, will be pneumatically operated and controlled. The throttle valves will be pneumatically operated, with control signals from the controller being electrical. Transducers will be used to interface the electrical signals to the motive pneumatic system.

The main fuel oil pump is protected on the inlet from foreign particle ingestion by a full flow, five (5) micron, pleated paper filter. Experience has found this filter to be superior to the previously used 200 micron scraper or self-cleaning type, insofar as improving pump reliability. The filter on the downstream side of the pump will also be a five (5) micron full flow, pleated paper cartridge type. All piping downstream of this filter will be corrosion-resistant (stainless) material, or internally coated carbon steel to ensure cleanliness of the fuel passing through the close tolerances of the fuel distributor and fuel oil nozzles.

5.1.3.4 ELECTRICAL AND CONTROL PACKAGE

The voltage regulator is installed in an indoor switchgear cubicle, designed for front access, and includes all equipment necessary to receive energy from the permanent magnet generator (PMG) located on the exciter shaft, rectify it and return it to the stationary field of the Brushless Exciter.

Three-phase voltage, from potential transformers connected to the generator bus, provides a voltage signal to the voltage error detector. To this is added a signal from the reactive current compensator representative of line current and power factor. The resultant voltage is rectified, filtered and compared to a reference voltage in the voltage error detector. The reference voltage is set by the motor operated voltage adjuster and can be changed by operation of "Volt-Raise" and "Volt-Lower" pushbuttons on the operator's control panel.

The error signal is then fed to one of the auction inputs of a signal mixer where it is compared to any limiting signals from optional limiting modules, as supplied, such as the Maximum Excitation Limiter, Volts per Hertz Limiter, etc. This signal is then summed with the output signal from the base adjuster at the firing circuit module.

The base adjuster establishes the base value of excitation, and can be changed by use of raise-lower pushbuttons on the operator's control panel. The error signal from the voltage error detector indicates a need for a variation in excitation from this base level. In addition to calling for a change in excitation level, the error signal can be fed to an optional base adjuster follower module. This module signals the base adjuster to change the base level of excitation to the new condition. Thus, the base level of excitation continuously follows the load requirements, and if, for any reason, the error signal is lost, the excitation level will remain at the latest level set, rather than running back to minimum load.

The firing circuit module generates a DC pulse output that is variable from 0^{o} to 180^{o} with respect to the positive (anode positive) supply to the silicon controlled rectifiers (SCR) in the power amplifier. The SCRs are rendered conducting once in each cycle at the time called for by the pulse from the firing circuit. The earlier in the cycle the thyristors are switched on, the greater is the energy output of the amplifier to the exciter field.

In order to provide maximum operational reliability of the voltage regulator, dual power amplifiers and pulse generators are supplied. In addition, two full-capacity 24 VDC power supplies are included in the excitation switchgear cubicle.

All the energy required by the excitation system is supplied by the permanent magnet generator (PMG) in the brushless exciter. A DB-15 electrically operated air circuit breaker connects and protects the PMG supply to the excitation system and is located in the excitation cubicle. This breaker can be operated either manually from the operator's control panel, or automatically by the control system.

The voltage regulator components are rack-mounted as modules in the excitation cubicles for ease of maintenance. These modules are readily accessible and can be quickly removed and replaced, if necessary.

The protective relay panel is an indoor panel, having a front swinging door. The protective and lockout relays are semi-flush mounted on the door, while the required auxiliary relays are located inside the panel.

The protective relays are mounted in Flexitest cases, which, among other unique advantages, includes a test switch mounted in the relay case rather than elsewhere on the panel. The trip circuit on all Flexitest cases is identified with a red handle located on the right side of the switch, reminding a user to open that circuit first to avoid tripping the generator while performing routine relay maintenance.

The main AC control center contains the majority of combination starter assemblies or feeder breakers for the auxiliary loads of the plant.

The main horizontal three-phase bus extends the complete length of the structure, and is supported by non-tracking, glass-reinforced polyester insulators, separated from the top-most drawout units by a horizontal steel barrier. This barrier prevents accidental contact with the hot bus. Power is distributed to each vertical section by a three-phase vertical bus, bolted to the main bus in the top of the section. Full-depth wireways are provided, covered by hinged doors secured by quarter-turn fasteners.

The individual starter or feeder breaker is mounted in a drawout unit completely isolated from adjacent units. Plug-in stabs, assembled into the breaker, make contact with the vertical bus. Each drawout unit can be padlocked in a disconnected position, or easily removed from the structure for maintenance.

Where available (through size 4) combination starters incorporating Type MCP motor circuit protectors are supplied. The MCP is designed specifically for motor circuits and provides optimum protection with maximum convenience. Operating on the magnetic principle, the breaker incorporates three current sensors with a single trip point adjustment. In this way, protection is customized for each individual motor.

In addition to the starter and feeder breaker units, a 480-volt to 120/240 volt transformer is supplied, feeding a distribution panelboard. This panelboard, located in one end of the motor-control center supplies the miscellaneous small loads such as lighting, convenience recepticles, air conditioners, etc.

The DC control center is of the same design as the main AC control center. The 125-volt bus is fed by the battery charger, and supplies such loads as the battery, inverter, emergency backup pumps and turning gear. A DC panelboard is included which distributes power to the emergency lighting and various control and protection assemblies requiring 125 volt DC supplies. The battery charger fulfills the dual function of providing power to the DC bus during normal operation, as well as maintaining a floating charge on the station battery.

The charger contains a solid-state rectifier and is provided with an output voltmeter and ammeter on the front. 480-volt 3-phase power is supplied to the charger from the AC motor control center. The charger automatically regulates the output voltage to $\pm 1\%$ with load variations of from 0 to 100 percent. A low-voltage relay provides an alarm if the DC bus voltage drops to a dangerously low level.

The unit battery is a 60-cell lead-acid type, rated 125 volts, sized in ampere rating to supply emergency DC power for controls lube and seal oil pumps and turning gear for a three (3) hour period.

5.2 HEAT RECOVERY STEAM GENERATOR

5.2.1 Functional Description

The heat recovery steam generator (HRSG) extracts heat from the gas turbine exhaust gas and returns this heat to the combined cycle process in the form of steam to power a steam turbine. The HRSG receives the exhaust gas from the turbine through a duct which is connected to and aligned axially with the turbine exhaust. Entry of the gas into the HRSG is through a diffuser duct which terminates in a "Y" shaped section, splitting the gas into two parallel flowpaths. Splitting the gas into two paths allows the tube modules to be designed for shop fabrication and rail shipment to the erection site. A turning vane module, in each flowpath, then turns the gas flow upwards into the tube bank modules.

In the first module the gas flows over the throttle steam superheater tubes and the intermediate pressure reheat tube bank. The exhaust gas then flows in turn across the tubes in the high-pressure evaporator, the economizer and the low-pressure evaporator before passing through the exhaust transition section and the motor operated stack covers. A sectional view of the HRSG is shown on Figure 5.2-1 and Figure 5.2-2 shows the unit in its modular form.

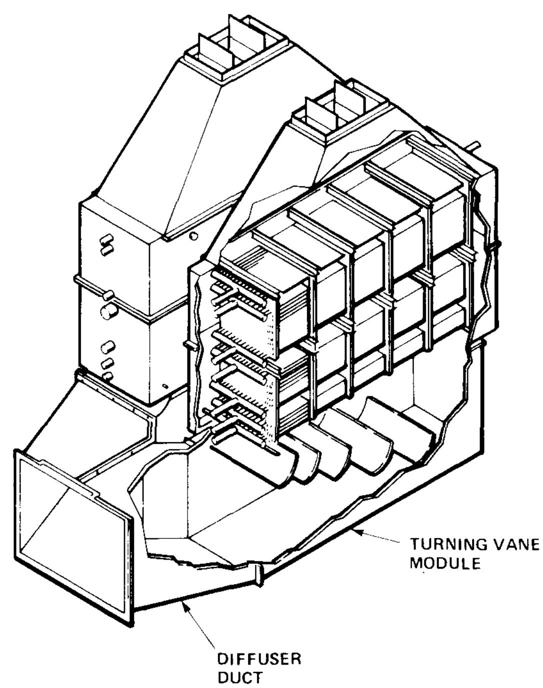
5.2.2 Equipment Description

SUPERHEATER - AND REHEAT SECTION

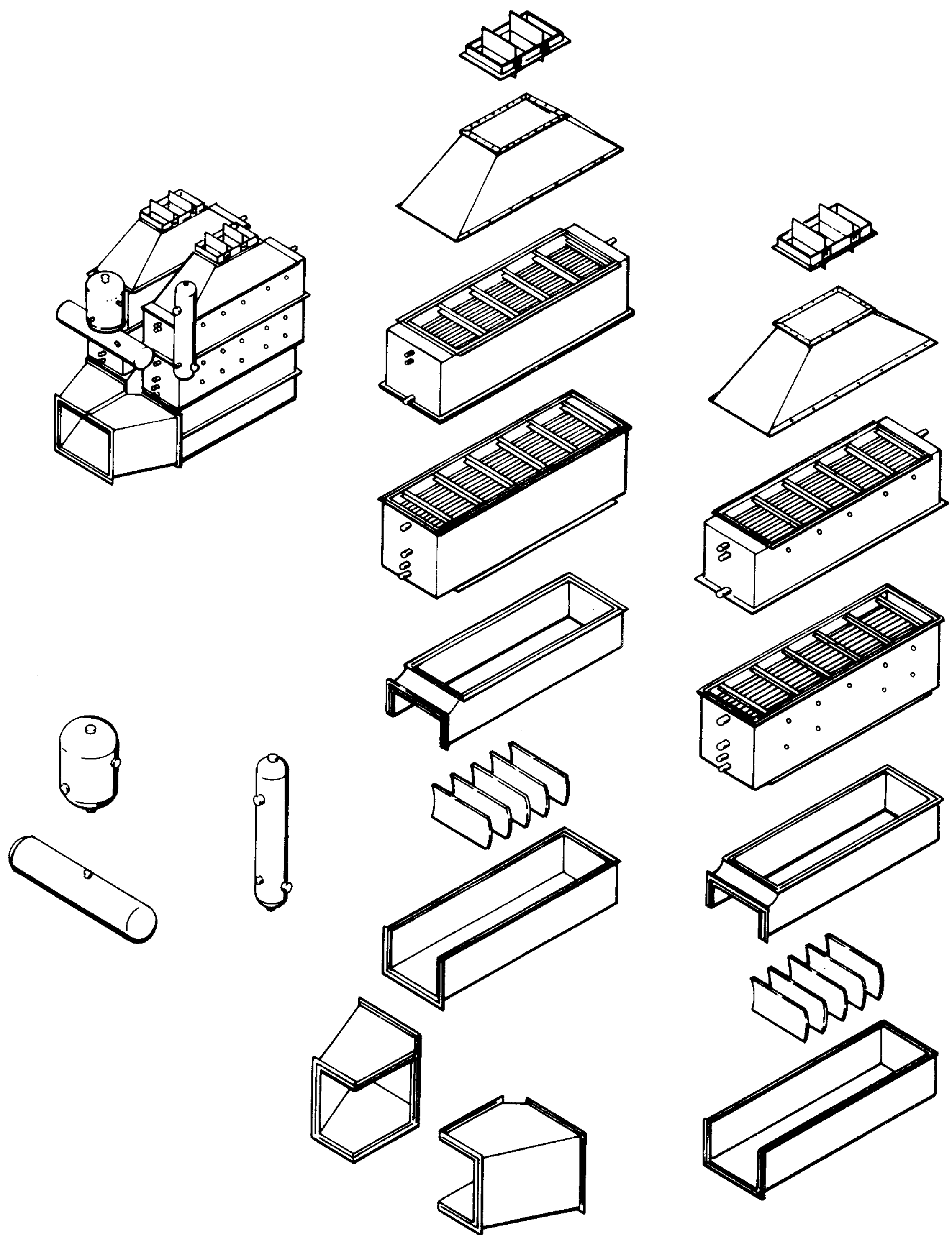
This section consists of banks of tubes welded into headers; one header is connected by welded pipe to the drum while the outlet header is free to float for thermal expansion.

HIGH-PRESSURE EVAPORATOR

The high-pressure evaporator section consists of one bank welded into a header at the top and a header at the bottom. Each of these headers is fixed but the return U-bends of each serpentine are free to float. This arrangement gives excellent mixing characteristics at reasonable tubeside pressure drop and ability to operate over the full range of steam production without stagnation of flow.



HEAT RECOVERY STEAM GENERATOR
Figure 5.2-1



HEAT RECOVERY STEAM GENERATOR MODULES
Figure 5.2-2

ECONOMIZER

The economizer section consists of one bank welded into a header at the bottom and a header at the top. One header is connected by welded pipe to the high-pressure drum and the feedwater control valve. The other is connected through welded pipe to the boiler feedpump.

LOW-PRESSURE EVAPORATOR

The low-pressure evaporator consists of one bank welded into a header at the top and a header at the bottom. Its design is similar to that of the high-pressure evaporator.

STRUCTURES

The strong integral structure which encloses the heat transfer modules is a carbon steel casing fully insulated and lagged internally. The casing is a structural member transferring loads from the tube support structure to external structural steel. The internal lagging protects the insulation against erosion by the exhaust gas flow.

The internal support structure consists of I-beams fastened into the outer casing. Banks of tubes are suspended from these I-beams with supports on which the tubes rest. The number of supports is selected to limit deflection of tubes and provide adequate strength at the elevated temperatures.

DEAERATOR

A deaerator with continuous deaeration is provided for satisfactory operation at all loads. The Spray Tray utilizes controlled parallel downflow. The unit is constructed in accordance with ASME Code Section VIII. The additional steam and flashing condensate inlets are located on the top in the steam chest area, without the use of any external mixing chamber. The Spray Tray design offers the advantage of being able to introduce the various different temperature and mixture flows while operating at maximum efficiency. Flashing steam will be fully utilized in the deaeration of lower temperature inlet flows.

STEAM DRUM

The vertical steam drum and moisture separator are designed using technology developed for and being used in nuclear Steam Generators. This apparatus is backed by experience with 94 units in operation and 77 more shipped or under construction. The design has been successful on Submarine Nuclear Steam Supplies where high drum solids, rapid load changes, drum motion, and compactness are all demanding application characteristics.

The vertical steam drum takes the steam-water mixture from the evaporator section of the heat recovery boiler, separates the water from the steam and passes the high purity steam on to the superheater. The separation process takes place in the centrifugal (primary) separator and in the positive entrainment moisture separator (secondary).

The vertical steam drum has the following characteristics:

- Small diameter construction with associated thinner walls resulting in minimal thermal stresses incurred. This reduces the cycling limitations imposed by the drum and/or possibility of stress cracking and failure.

- All welded construction and minimum number of external nozzle fittings provide convenient and expeditious installation.

Secondary separation of water from steam is accomplished in the upper part of the steam drum by utilization of the positive entrainment moisture separators. The separators which are compact and accessible from one manway, allow for convenient inspection and service. The separator channels are uniformly spaced by use of the Westinghouse patented arrangement providing a uniform velocity distribution and inherent equal contribution of moisture separation over the entire separator bank. The separator channels formed from a single sheet of metal provide consistent separation of moisture exceeding the performance of the industry standard. The design incorporates the advantages of equi-velocity and water droplet entrainment to ensure minimum carryover even during the most rapid load swing.

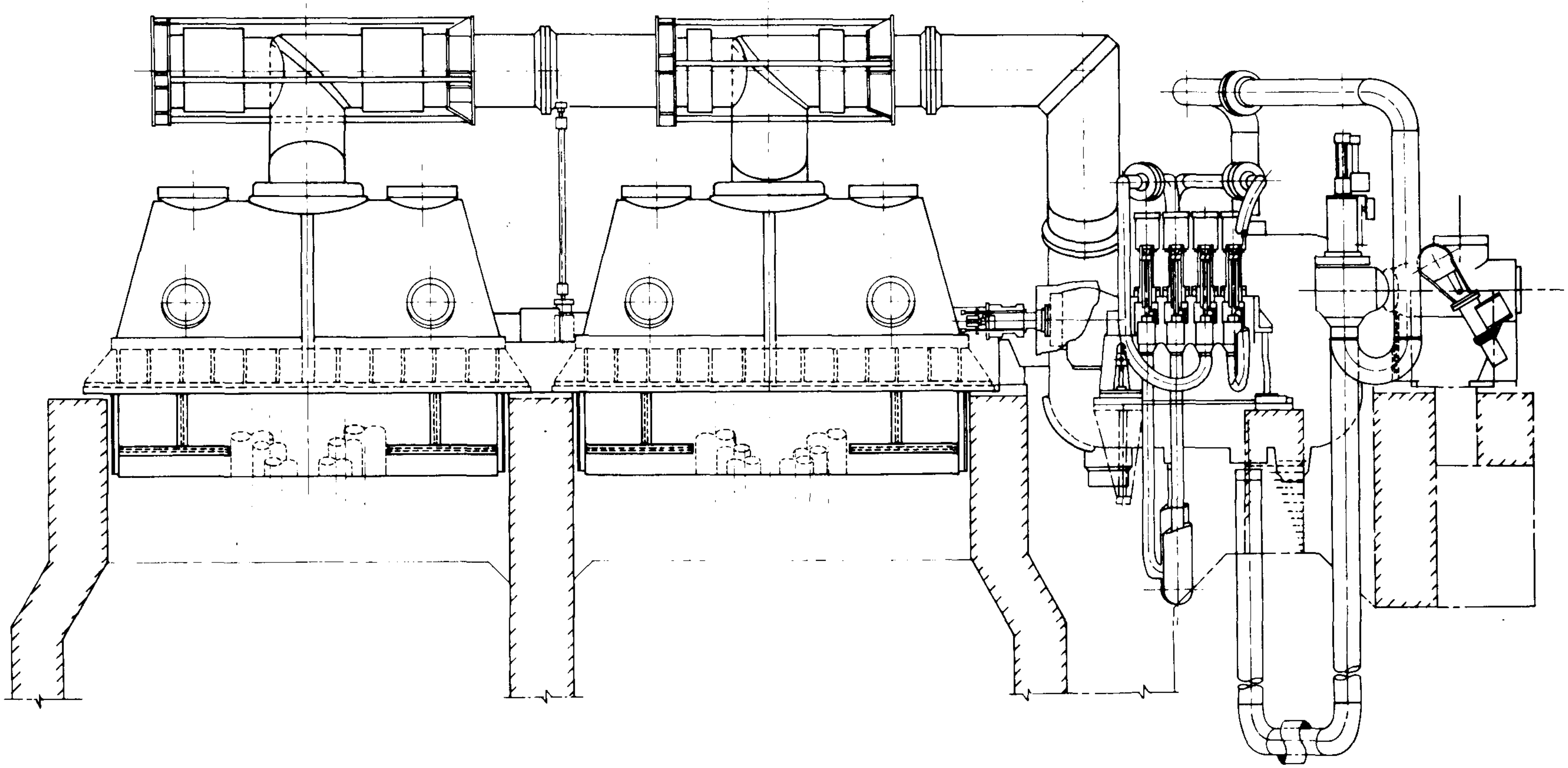
HIGH-PRESSURE CIRCULATING PUMP

Westinghouse provides a vertical, in-line, high-pressure circulating pump with a close-coupled motor. The pump is mounted directly in the piping and from a support standpoint is treated the same as a valve having the same weight. Concrete foundations and associated springs to accommodate differential expansion are not required. The pump floats with the piping system, thus minimizing piping forces and moments. Applied piping loads have no effect on motor-to-pump alignment. The pumps are "close-coupled" having a one-piece motor-pump shaft thus eliminating all problems associated with coupling alignment maintenance.

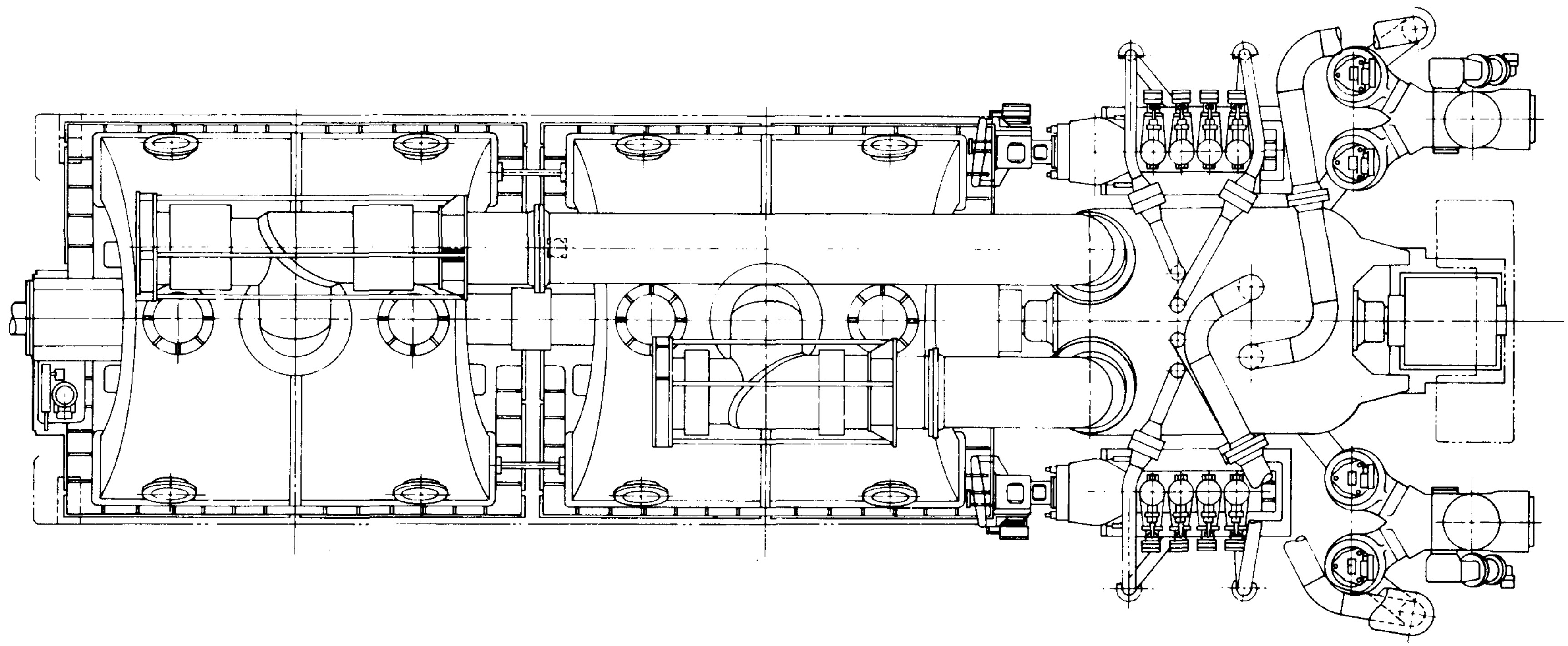
5.3 STEAM TURBINE GENERATOR

5.3.1 Steam Turbine

The 461 MW steam turbine generator selected for this study is a state-of-the-art machine, operating at 3600 rpm. The tandem compound steam turbine consists of a common high-pressure/intermediate-pressure cylinder and two low-pressure/double-flow cylinders exhausting to a condenser at 2.5" HgA. Throttle steam pressure is 2400 psig with an initial steam temperature of 1000°F and with a single reheat to 1000°F. An elevation of the steam turbine is shown on Figure 5.3-1, and a plan view is shown on Figure 5.3-2.



STEAM TURBINE ELEVATION
Figure 5.3-1

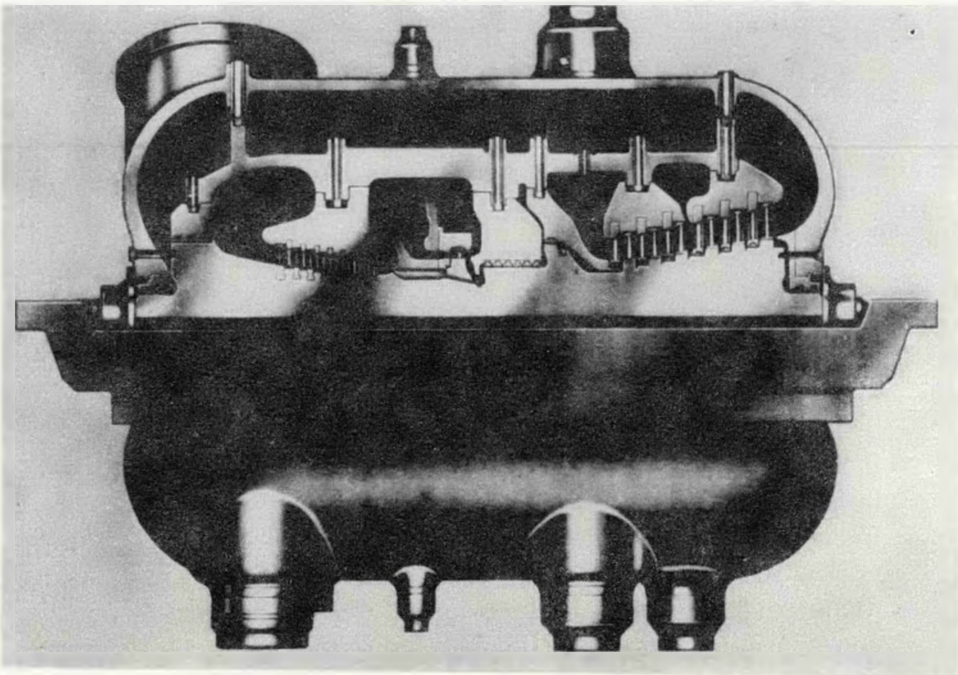


STEAM TURBINE PLAN
Figure 5.3-2

The combined stop-throttle valve-steam chest assemblies and the reheat stop-interceptor valve assemblies are anchored to the foundation and not to the cylinder as is shown in Figure 5.3-2. This design allows station piping loads to be transmitted to the foundation and not to the cylinder thus reducing the piping induced stresses in the cylinder. In addition, the higher temperature valve and steam chest assemblies are thermally isolated from the cooler cylinder, reducing thermal stress levels.

Steam is admitted from the eight stop valves through eight (8) pipes, four (4) through the cover and four (4) through the base. This steam enters the high-pressure elements through six (6) separate nozzle chambers. The nozzle chambers are flexibly welded and keyed to the inner cylinder. They are also keyed to each other. This allows for unequal radial expansion and reduces thermal stress between the nozzle chamber and the turbine casing during cyclic operation.

Figure 5.3-3 shows a section through the upper half of the HP-IP cylinder. Steam enters the small high-pressure pipes just to the left of the center and expands from left to right through the first stage, then reverses itself expanding toward the left through the remaining HP stages. The reheated IP steam enters through the intermediate sized pipe just to the right of center, expands to the right through the IP stages and then travels between the inner and outer cylinders to the left end where it leaves the element by way of two crossover pipes for the low-pressure (LP) elements.



HP-IP CYLINDER
Figure 5.3-3

The full inner cylinder is used to support high-temperature blade rings in both the high-pressure and intermediate-pressure blade paths. This design minimizes temperature gradients across structural walls resulting in lower thermal stress. The inner cylinders also act as a pressure vessel permitting thinner outer cylinder walls with a corresponding reduction in horizontal flange size and, therefore, lower thermal stresses during cyclic operation.

Separate blade rings are used to support the stationary blading within the cylinder. The centerline support of the blade rings ensures alignment while allowing for differential expansion between the blade ring and cylinder. The separate blade ring design allows freedom of expansion of the blade ring independent of the casing, reducing thermal stress and misalignment during cyclic operation. Lower temperature steam is utilized to cool the rotor at both the main inlet and the reheat inlet. The rotor at the reheat inlet is cooled by dummy leakage steam. The reduction in rotor temperature more than doubles the rotor creep rupture life.

Westinghouse follows the high-temperature design philosophy in the low-pressure (LP) turbines where the potential temperature differentials are the highest in the unit. The LP turbine is constructed with an outer cylinder and two inner cylinders and a thermal shield. The design provides three walls over which the temperature differential between the inlet and the condenser is distributed. As in the HP-IP element, each stationary part is designed so as not to impose thermal stress upon an adjacent part. Liberal seal clearances are used for all inter-stage sealing. The LP turbine casing is manufactured as a fabrication to ensure uniform wall thickness for large stationary parts, thus minimizing thermal stress. This construction provides a liberal exhaust hood configuration to minimize blade excitation forces.

This steam turbine-generator is composed of pre-engineered components of a proven design. Design improvements based on operating experience are incorporated in all subsequently manufactured similar units resulting in better, more reliable machines with each iteration.

5.3.2 Generator and Exciter

The generator driven by the steam turbine is directly and solidly coupled to the turbine and has a rating of 512 MVA, 0.9 pf, 24 KV, 60 Hz. The rated hydrogen pressure is 60 psig. Rating, temperature rises and insulation class will be in accordance with the governing ANSI standards. The main leads of the generator will be brought out the bottom of the generator shell through high-voltage bushings. Pre-wired current transformers are internally mounted on the main leads. The neutral connection will be made up internal to the generator and will include a neutral grounding transformer and grounding resistor. Each neutral lead will have pre-wired current transformers for metering and relaying.

Circuits requiring grounding are connected to the generator frame. Grounding pads on the generator frame provide for electrical connections to the external ground available at the installation site. The generator frame and the enclosing end brackets are fabricated from steel plate. The generator frame includes frame feet which are supported by the foundation. Stator construction includes a stacked and wound core within a fabricated cage. This cage is isolated from the frame by support from several flexible steel springs. The flexible steel springs allow the cage to distort radially with considerable freedom, but support it rigidly in the direction of torque loads. This mounting system serves to eliminate double frequency vibration.

The stator core consists of laminations made of high-grade, low-loss silicon sheet steel. Each lamination, after it is deburred, is insulated with aluminum phosphate material which bonds to the metal in such a way that the insulation will not chip or wear with age. The laminations are properly located and locked into position by means of a patented notching process so that they cannot become dislodged. Insulated through-bolts are then passed through the laminations and drawn tight to ensure a permanently tight core and uniform air gap. The magnetic end plates and non-magnetic finger plates are used to provide an electrical shield to minimize stator end-region heating. The stator winding has THERMALASTIC insulation. The impregnating resin used with this insulation will be the styrene modified epoxy.

Bracket type, self-aligning bearings support the rotor on the exciter and turbine ends. Bearing brackets are bolted solidly to the generator frame structure and are provided with stop dowels in the bottom half for locating purposes. Vibration detectors monitor vibrations on each of the bearing supports. Thermocouples are supplied in bearing drains to monitor oil temperature. Bearings can be removed without removing hydrogen from the machine.

Hydrogen pressure is maintained at 60 psig by a regulator located in the hydrogen system cabinet mounted on the side of the generator. Continuous circulation is maintained by a shaft-mounted axial blower. The hydrogen is directed through the air gap and over the rotor and stator conductor and then through horizontally mounted coolers located within the generator frame. The hydrogen passes across a radiator type cooler, giving up its heat to the auxiliary cooling water provided from balance of plant. A temperature detector monitors the cold-gas outlet of the cooler to ensure proper cooling of the generator. The generator will be capable of withstanding, without injury, a 30-second, 3-phase short circuit at the terminals when operating at rated KW, rated power factor, and a five (5) percent overvoltage with fixed excitation, provided the maximum phase current shall be limited by means of suitable reactance or resistance to a value which does not exceed the maximum phase current obtained from the 3-phase fault, in accordance with latest proposed ANSI standards.

The generator will also be capable of withstanding without injury, any other short circuit at its terminals provided the machine phase currents under fault conditions are such that the negative phase sequence currents (I_2), expressed in terms of per-unit stator current at rated KVA and the duration of the fault in seconds (t), are limited to values which give an integrated product (I_2^2t) equal to, or less than 10. The generator will operate successfully at rated KVA, frequency and power factor and gas pressure at any voltage not more than 5 percent above or below rated voltage.

The deviation factor of the open-circuit terminal voltage wave of the generator will operate successfully at rated KVA, frequency and power factor and gas pressure at any voltage not more than 5 percent above or below rated voltage.

The deviation factor of the open-circuit terminal voltage wave of the generator will not exceed ten (10) percent.

The brushless exciter is solidly coupled to the generator shaft and has sufficient strength to carry the torque developed by the starting device during startup to accelerate the turbine generator set to ignition and self-sustaining speed. A single pedestal bearing supports the exciter shaft on the outboard end. The exciter is rated 1750 KW at 500 volts, DC.

The regulator power source has permanent magnets located inside a steel ring attached to the shaft. The permanent magnet makes the set self sufficient, avoiding the necessity of an external source of power. The pilot exciter magnets are factory stabilized so that a short circuit on the pilot exciter armature or removal of the armature will not affect the magnetization level.

The core of the AC exciter is made of high-strength electrical sheet "donut" laminations mounted on the fluted shaft with a heavy interference fit. The shaft is a solid forging. Radial vents allow effective axial-radial ventilation. Rotor coils are shallow and special attention is given to consolidating the end turns. Glass polyester bands are used for this purpose.

The main components of the rotating rectifier are silicon diodes and indicating fuses. All rectifier components are mounted on the inside diameter of a high-strength steel retaining wheel. Each diode has an indicating fuse which can be observed while the generator is in service by use of a stroboscope light. The diodes rectify the AC power generated by the AC exciter. The system is protected against diode failure by the series-connected fuses with indicating device. The indicating devices permit checking for open fuses by stroboscopic light while the exciter is operating. Two (2) ground detection rings are provided for checking the condition of the insulation resistance to ground during operation. The circuitry is conservatively designed to permit operation of the unit, even when one fuse in each phase is open. In this mode of operation, there is no reduction in generator output power.

5.4 MAIN CONDENSER(S)

Two (2) condensers are provided, one beneath each of the two low-pressure turbine casings of the steam turbine. The condensers are designed to receive the turbine exhaust steam; cycle makeup water; drains from the feedwater heater; gland steam condenser and steam-jet air ejector condenser; and bypassed steam during startup and emergencies from the main steam system. The condenser is a surface type with deaerating capability. The water side is a two-pass radial flow design with divided water boxes and with the tubes positioned transverse to the turbine axis. The condenser hotwell has a five (5) minute storage capacity and sits at plant grade floor level. An expansion joint is located at each turbine exhaust connection. The water boxes are of fabricated steel, designed for 50 psig, and equipped with circulating water inlet and outlet butterfly type isolating valves and expansion joints. The twin shells are cross-connected by a large diameter duct between the steam domes and by piping between the hotwells.

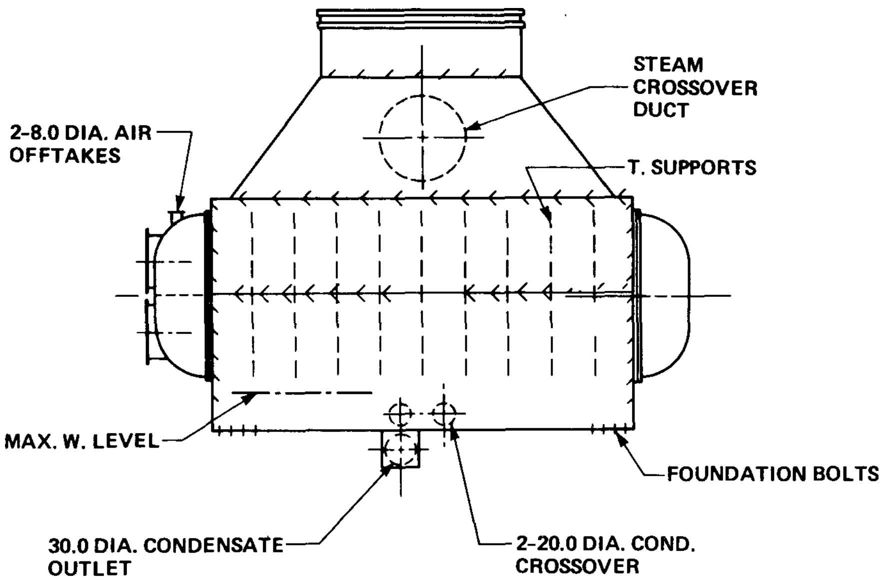
The condensers provide a heat duty of 2118 x 10^6 Btu/Hr at 2.5" HgA condensing pressure and ISO ambient conditions. The following design and performance characteristics are typical for condensers of this size and type:

Cooling Water Temperature Rise	20^oF
Water Side Pressure Drop	7.6 psi
Hotwell Storage Capacity (Holding Time)	5 min.
Water (Tube) Velocity	7 FPS
Tube Cleanliness Factor	.85
Terminal Temperature Difference	5^oF
Material of Construction:	
Main tubes - 18 BWG Admiralty	1 in. O.D.
Air Core Tubes - 18 BWG 90-10 Cu-Ni	1 in. O.D.
Tube Sheets - Muntz Metal	1 3/8 in. thick
Water Boxes - A-285-Gr. C. Carbon Steel	-
Shell & Steam Inlets - A-285-Gr. C. Carbon Steel	-
Corrosion Allowances	
Shell	0.063 in.
Water Boxes	0.25 in.

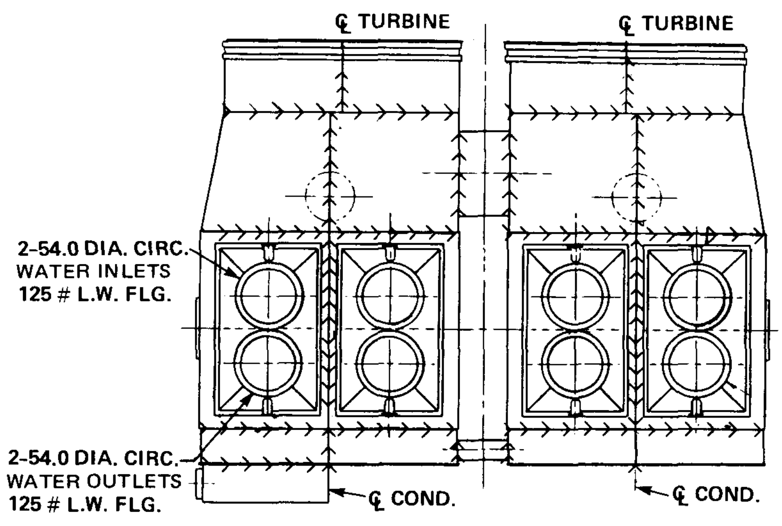
A side view and end view of this type of condenser is shown on Figures 5.4-1 and 5.4-2.

5.5 CONDENSATE PUMPS

Each of the three (3) 50 percent capacity condensate pumps will be motor-driven centrifugal-type units. The pumps will be installed in parallel with discharge check valves to permit the backup pump to come on the line immediately in the event of a malfunction of one of the pumps in service.



CONDENSER – SIDE VIEW
Figure 5.4-1



CONDENSER – END VIEW
Figure 5.4-2

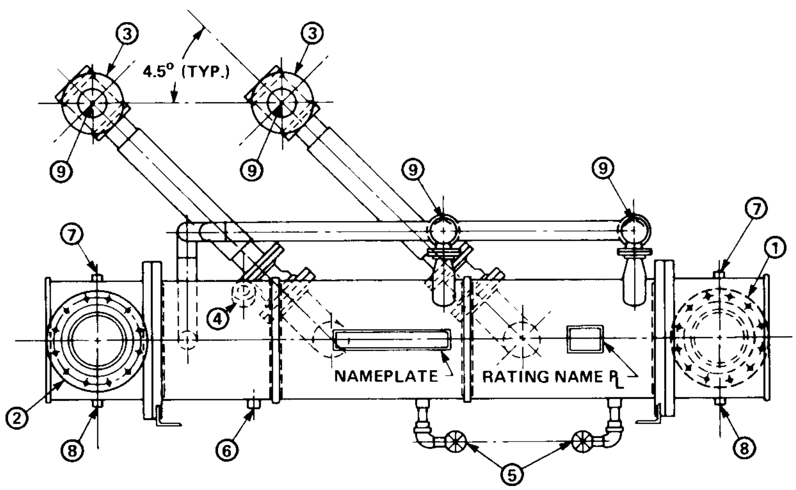
The pumps will be of the vertical multi-stage can type with closed, hydraulically-balanced impellers to minimize the axial thrust imposed on the driver. The first-stage impeller eye will be sufficiently large to permit operation with a minimum N.P.S.H. The shaft seal will be of the mechanical type with the seal faces exposed to the pump discharge flow, thus eliminating the need for external flushing piping. The pump shaft will be connected to the driver shaft by a flanged, rigid, coupling with provision for axial adjustment in order to set impeller clearances. The pump driver will be an electric motor with a solid shaft suitably locked against up thrust.

5.6 FEEDWATER HEATERS

The feedwater is heated as it leaves the condenser by passing through the air ejector condenser, the gland seal condenser and the low pressure feedwater heater.

5.6.1 Air Ejector Condenser

Air and other non-condensable vapors are removed from the main condenser via first-stage and second-stage ejectors, mounted on the inter and after condensers. General arrangement and connection details are shown in Figure 5.6-1.



ITEM	DESCRIPTION
1	CONDENSATE INLET
2	CONDENSATE OUTLET
3	AIR INLET
4	VENT (AFTER CONDENSER)
5	DRAIN (INTER CONDENSER)
6	DRAIN (AFTER CONDENSER)
7	VENT
8	DRAIN
9	GAUGE CONNECTOR

AIR EJECTOR CONDENSER
Figure 5.6-1

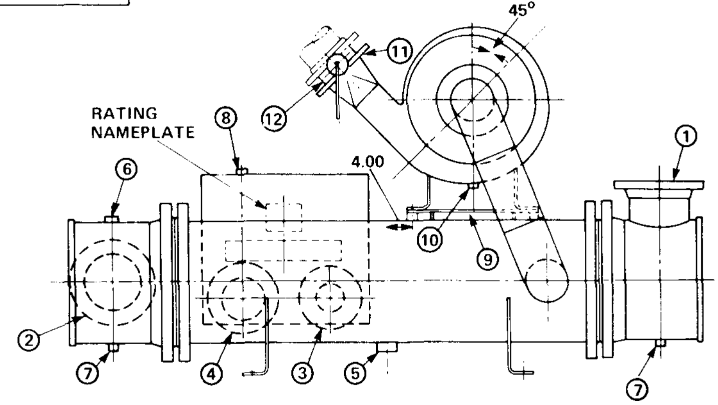
The gases are drawn into the first-stage mixing chambers by high-velocity steam jets. The mixture then flows through the first-stage diffusers and discharges into the inter-condenser compartments, where the steam is cooled via contact with the surface of the cool tubes. The heated condensate exits via the inter-condenser drains (5), Figure 5.6-1. From the inter-condenser compartments the gases and uncondensed vapors are piped to the second-stage ejectors, where they are entrained by steam jets and discharged through the diffusers into the after condenser. The steam is condensed and the air and other non-condensable vapors are removed via the vent (4). The condensate, heated, exits via the after condenser drain (6). The inter-condenser is divided into two compartments by the inner-tube sheet. The inter and after condensers are welded to the inner-tube sheet. The inter and after condenser shells are fabricated of carbon steel, with integral tube sheets. The tubes are expanded into each tube sheet.

5.6.2 Gland Steam Condenser

The gland steam condenser is a small surface unit which operates slightly below atmospheric pressure. It consists of a fabricated shell with integral inlet and discharge tube plates. The inlet and discharge water chambers are bolted to their respective tube plates and are sealed from steam and water leakage by asbestos sheet packing gaskets. The tubes are rolled into the tube plates at both ends.

The circulating water enters the inlet chamber, flows through the tubes in the gland condenser, and exits via the discharge chamber. Referring to Figure 5.6-2, the gland

ITEM	SIZE	DESCRIPTION
1	8.00 DIA.	CONDENSATE INLET
2	8.00 DIA.	CONDENSATE OUTLET
3	4.00 DIA.	STEAM INLET
4	6.00 DIA.	VALVE STEM LEAK-OFF
5	1.00 P.T.	DRAIN (SHELL) 3000 =
6	- .75 P.T.	VENT (CHAMBER) 3000 =
7	2 -.75 P.T.	DRAIN (CHAMBER) 3000 =
8	.75 P.T.	PRESSURE CONNECTION 3000 =
9	.50 P.T.	GAUGE CONNECTION 3000 =
10	.50 P.T.	DRAIN (TO WASTE) 3000 =
11	4.00 DIA.	AIR EXHAUST
12	4.00 DIA.	VALVE VENT VACUUM ADJ.



GLAND STEAM CONDENSER
Figure 5.6-2

seal steam is admitted into the condensing section via the steam inlet (3) and then passes among the tubes. The air and other non-condensable vapors are discharged to atmosphere by air exhausters. The drain (9), of the exhausters, is open for removal of condensate. The condensate formed in the gland steam condenser shell is removed via the drain (5) and trapped back to the condenser hotwell. A motor-driven exhauster, connected to the shell side of the gland condenser, removes the air and other non-condensable vapors that have leaked through the glands and discharges them to the atmosphere. This condenser must operate at a sufficient vacuum to maintain the slightly sub-atmospheric pressure at the glands.

5.6.3 Feedwater Heater

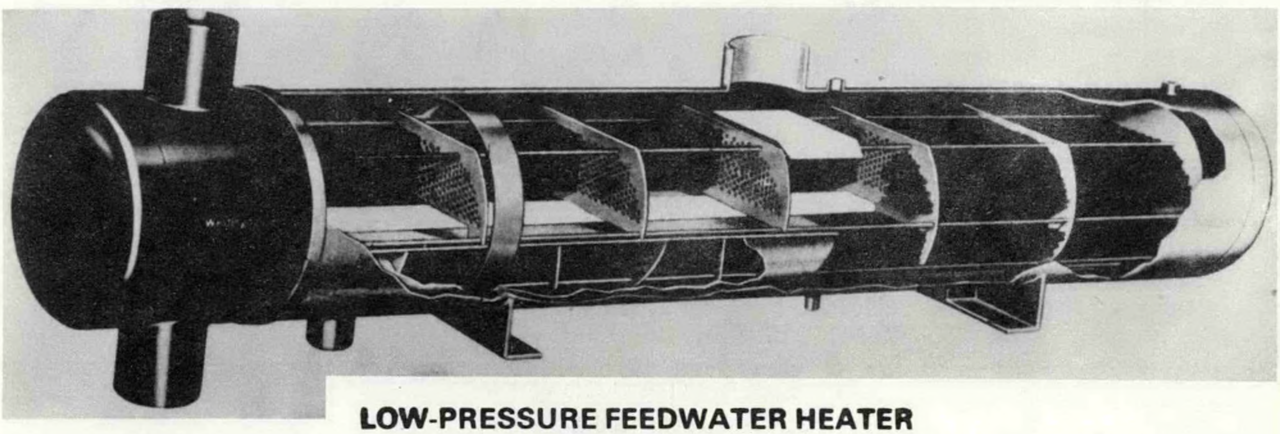
The low-pressure feedwater heater raises the temperature of the condensate going to the HRSG by absorbing heat from low-pressure steam extracted from the steam turbine. The feedwater heater will be a two (2) pass, horizontal shell and tube type heater. To minimize air-in leakage, the shell will be of welded construction with no flanged joints. The heater will be constructed in accordance with the ASME Unfired Pressure Vessel Code, Section VIII. A typical low-pressure feedwater heater is shown on Figure 5.6-3.

The shell and heads will be constructed of carbon steel and a corrosion allowance of 1/16 inch is included in the thickness of all carbon steel pressure vessel components. Tube material will be 70-30 Nickel-Copper (Monel) composition, stress relieved temper. The tubes will be roller expanded into carbon steel tube plates. The heater condensate will be trapped back to the condenser hotwell.

5.7 DEAERATOR

A vertical deaerating heater mounted on a horizontal storage tank is provided in the reference design. The deaerator receives extraction steam from the low-pressure steam turbine.

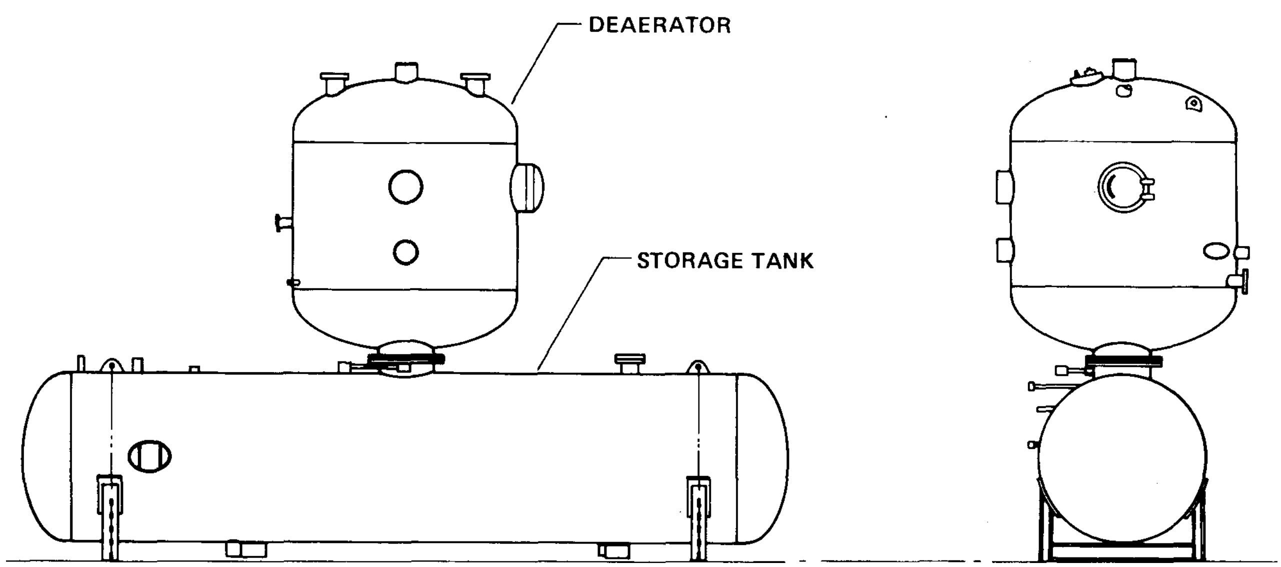
The heater utilizes the steam by spraying the incoming water into an atmosphere of steam in the preheater section; it then mixes this water with fresh incoming steam in the deaerator section.



LOW-PRESSURE FEEDWATER HEATER
Figure 5.6-3

Basically, the first-stage of deaeration occurs in the spray section, in which the influent is discharged through the spray valve or valves, in a conical shower-like pattern, into a steaming atmosphere. The sprayed and condensed water is collected in the distribution troughs and the top layer of trays. The water in this section has been heated to within $2^{o}F - 4^{o}F$ of the steam temperature by intermingling with the steam and has most of the dissolved oxygen and CO_2 as well as the non-condensable gases removed. The self-adjusting, non-clogging type spray valves are designed and accordingly manufactured to produce an even spray cross-section under all operating load conditions. Consequently, under each load condition, a constant temperature and uniform gas removal has been attained at this point. The spray valves are arranged with respect to the distribution troughs to ensure that all the gases which could be removed have been removed prior to the sprayed water particles hitting the trays.

The water in the upper layer of trays, still containing some traces of non-condensable gases, is introduced into the second-stage of deaeration, in the tray stack section, where the water is intimately mixed with the high energy steam which has just entered into the deaerator. The water which leaves the second stage falls to the storage tank where it is stored for use. At this time the water is completely deaerated and is heated to the steam temperature corresponding to the pressure within the vessel. The deaerator and storage tank assembly is shown on Figure 5.7-1.



DEAERATOR AND STORAGE TANK
Figure 5.7-1

5.8 BOILER FEEDPUMPS

The boiler feedpump will be a horizontal, multi-stage centrifugal type pump directly driven by an electric motor. The pump will be coupled to the motor by a flexible coupling. The motor-boiler feedpump will be assembled together on a fabricated steel baseplate complete with a common lubricating system and integral lube and cooling water piping.

The pump casing will be cylindrical of forged steel material, supported at the centerline with welded suction and discharge flanged nozzles. The endheads of the pump will have a vertical joint with the pump case and will be removable to permit maintenance. The internal assembly of the pump will be constructed so as to permit one piece removal and installation. The end assembly will be possible without disturbing the pump driver and piping. This type of pump construction assures the strength required for the operating pressures and eliminates the possibility of joint leakage. The pump shaft will be supported by pressure lubricated sleeve bearings. Axial thrust of the pump shaft will be carried by a double Kingsbury thrust bearing.

A continuous pressure lubricating system will provide oil to the bearings of both pump and motor. The reservoir for the lube system will have a minimum capacity of five (5) times the rated flow of the main oil pump and will be fabricated into the baseplate. The main lube oil pump will be shaft-driven from the shaft of the boiler feedpump. A DC motor-driven pump will be used for startup and shutdown. Pump suction will be taken from the reservoir, and will pass through an oil-to-water cooler and a filter before it is passed into the bearings. The pump will be fitted with mechanical shaft seals using condensate as the sealing and cooling medium.

The supervisory instrumentation will be connected to a control panel mounted on the common baseplate for local indication. Alarms and trips will be connected to provide a single annunciated point for each back at the central control room.

5.9 CHEMICAL FEED SYSTEM

The basic equipment of the chemical feed system are the chemical treatment tanks and associated pumps.

The ammonia and hydrazine tanks will be identical, closed vessels, constructed of stainless steel, each having its own auxiliary measuring tank, used for filling the main tank. Each tank will have a guarded liquid level gauge and a level switch to annunciate low liquid level. Since these tanks may be housed within a package enclosure, the level switches will be positioned and designed so that they can be removed within the confines of the enclosure.

The phosphate tank will be constructed of steel with a hinged cover. The tank will be equipped with a dissolving basket (used for filling), a motor-driven mixer (used for agitation and placing the phosphate in solution), and a level switch to signal a low-level condition. Injection pumps will be mounted as part of each tank assembly and oriented to permit adjustment and maintenance when the tank pump assembly is in its final installation as part of an auxiliary package. The pumps will be fitted with suction and discharge check and block valves and discharge pressure gauges and snubbers. Each gauge will have a block valve to permit isolation. The injection pumps will be motor-driven, positive displacement metering pumps designed for pumping corrosive or toxic liquids. Each pump will have a manual capacity adjustment, which can be made whether the pump is running or not. The pump will have its own built-in internal relief valve.

5.10 INSTRUMENT AIR COMPRESSOR

The instrument air compressor supplied as part of the instrument air package is a non-lubricated, reciprocating compressor, belt-driven by an electric motor.

The compressor consists of a crankcase and a single compressor cylinder connected to the crankcase through a distance piece. The crosshead is integral with the crankcase. A force feed lubrication system is used to supply oil to the main bearings, crankpin bushings, crosshead pin bushing and crosshead. An internal gear type pump driven from the crankshaft supplies the oil pressure. The pump draws oil from the sump through a coarse screen and forces oil through a filter to the moving parts. An automatic oil-pressure shutdown device stops the machine in case of lubricating oil pressure failure. The non-lubricated cylinder prohibits contact of the air being compressed with lubricants.

A TFE rider ring on the piston prevents metal-to-metal contact with the cylinder base. TFE piston rings maintain proper wall pressure. The double-acting cylinder is cooled by a water jacket. Each inlet valve is fitted with a pressure actuated unloader as a means of unloading the compressor cylinder either for starting or for capacity control during operation. In operation, the compressor will pump air, loading and unloading, for ten (10) minutes, as demand requires. The compressor will then shut down until air demand requires the unit to come on line again. Operating control will be automatic as a function of receiver tank air pressure. The compressor will be protected to shut down on high discharge air temperature.

5.11 VALVES

All valves installed within the plant will be in accordance with ANSI pressure-temperature ratings and will conform to the applicable portions of ANSI B 31.1.0., Code for Power Piping. Construction features for standard valves are given in Table 5.11-1.

The design and selection of all valves employed in the plant will be coordinated so as to hold separate supply sources to a minimum. This will maximize interchangeability of parts with minimum spare parts inventory.

Identification plates will be provided and permanently attached to each valve. In addition, direction of flow nameplates or stamping will be provided on special valves. Valves having handwheels will have rotation arrows for opening and closing.

TABLE 5.11-1
VALVE CONSTRUCTION FEATURES AND MATERIALS

GATES, GLOBE, CHECK AND BUTTERFLY VALVES	
Group I	
Class	150# ANSI Standard
Type	Gates, Globes - O.S. & Y., Bolted bonnet joint Checks - Tilting disc, swing disc and lift bolted bonnet
Seat & Disc Facing	Stellite
Stem	ASTM A182 Grade F6
Body, Bonnet & Disc	ASTM A216 Gr WCB ASTM A105
Group II	
Class	300# ANSI Standard
Type	Gates, Globes - O.S. & Y., Bolted bonnet Checks - Swing disc and lift bolted bonnet
Seat & Disc Facing	Stellite
Stem	ASTM A182 Grade F6
Body, Bonnet & Disc	ASTM A216 Gr WCB ASTM A105
Group III	
Class	400# ANSI Standard
Type	Gates, Globes - O.S. & Y., Bolted bonnet joint Checks - Bolted bonnet
Seat & Disc Facing	Stellite
Stem	ASTM A182 Grade F6
Body, Bonnet & Disc	ASTM A216 Gr WCB ASTM A105
Group IV	
Class	600# ANSI Standard
Type	Gates, Globes - O.S. & Y., Bolted or pressure seal Bonnet Joint Checks - Bolted bonnet or pressure seal
Seat & Disc Facing	Stellite
Stem	ASTM A182 Grade F6
Body, Bonnet & Disc	ASTM A216 Gr WCB ASTM A105
Group V	
Class	900# ANSI Standard
Type	O.S. & Y., Pressure seal bonnet joint

GATES, GLOBE, CHECK AND BUTTERFLY VALVES	
Group V (Continued)	
Seat & Disc Facing	Stellite
Stem	ASTM A182 Grade F6
Body, Bonnet & Disc	ASTM A216 Gr WCB ASTM A105
Group VI	
Class	1500# ANSI Standard
Type	O.S. & Y., Pressure Seal Bonnet
Seat & Disc Facing	Stellite
Stem	ASTM A182 Grade F6
Body, Bonnet	ASTM A217 Grade WC6 ASTM A182 Grade F 11
Disc	A182 Grade F 11
Group VII	
Class	AWWA 75B AWWA 150B
Type	Rubber-seated butterfly
Shaft	ASTM A182 F6 Type 304 SS
Body	ASTM A126 Class B
Disc	CI ASTM A48, Cl. 40 with 0.003" chromium plated hardened edge
Seat	Natural gum rubber (to 190F) synthetic rubber (for temp >190F) Buna - N.
Group VIII	
Class	2-1/2" through 12"; 175# (NFPA No. 29A)
Type	Gates - O.S. & Y., Bolted Bonnet
Trim: Seats Stem	Bronze Rolled bronze ASTM B132, Alloy A
Body, Bonnet & Disc	ASTM A126 Grade B
Group IX	
Class	3" and larger AWWA 150#
Type	Gates - NRS bolted bonnet
Stem	Rolled bronze ASTM B132, Alloy A
Extension stem	Rolled bronze ASTM B132, Alloy A
Body	ASTM A126 Grade B
Valve box	ASTM A126 Class B
Seat & Disc	Bronze

BLEEDER CHECK VALVES AND STOP-CHECK VALVES	
Group X	
Class	600# ANSI Standard
Type	Reverse flow check
Base Material	Cast carbon steel - ASTM A216 Gr WCB

BLEEDER CHECK VALVES AND STOP-CHECK VALVES	
Group X (Continued)	
Trim	Stellite
Bonnet Design	Pressure seal
Positive Closing Cylinder	Cast carbon steel ASTM A216 Gr WCB
Group XI	
Class	400# ANSI Standard
Type	Reverse flow check
Base Material	Cast alloy steel - ASTM A217 Gr WC6
Trim	Stellite
Bonnet Design	Pressure seal
Positive Closing Cylinder	Cast carbon steel ASTM A216 Gr WCB
Group XII	
Class	300# ANSI Standard
Type	Reverse flow check
Design Press. - Temp Rating	190 psig and 735 F
Base Material	Cast carbon steel - ASTM A216 Gr WCB
Trim	Stellite (Base) Stainless Steel (Alternate)
Bonnet Design	Bolted
Positive Closing Cylinder	Cast carbon steel - ASTM A216 Gr WCB
Group XIII	
Class	300# ANSI Standard
Type	Iso-Check
Base Material	Cast carbon steel - ASTM A216 Gr WCB
Trim	Stellite (Base) Stainless Steel (Alternate)
Bonnet Design	Bolted
Positive Closing Cylinder	Cast carbon steel - ASTM A216 Gr WCB
Group XIV	
Class	150# ANSI Standard
Type	Iso-Check
Base Material	Cast carbon steel - ASTM A216 Gr WCB
Trim	Stainless steel
Bonnet Design	Bolted
Positive Closing Cylinder	Cast carbon steel - ASTM A216 Gr WCB

5.12 STEAM, WATER AND AUXILIARY PIPING

Piping within the power block area of the plant covers steam, condensate, feedwater, vent, drain, auxiliary cooling, air, hydrogen and carbon dioxide gases, fuel, fire protection and chemical feed. All piping will be designed, fabricated and inspected in accordance with ANSI B 31.1.0 code for Power Piping.

Pipe interconnecting the combustion turbine generator unit and its auxiliary packages will be designed by the equipment manufacturer. All piping will be factory fabricated, and where possible, factory assembled into pre-fabricated pipe racks, complete with necessary supports and bracing. These pipe racks will be oriented axially alongside the turbine generator unit and will contain as an integral part of the rack design, a maintenance and access platform to the horizontal joint of the turbine and other rotating equipment. All pipe runs within equipment enclosures, such as the combustion turbine enclosure, will be factory-fabricated with final assembly in the field, where factory assembly is not possible due to shipping limitations. All remaining plant piping, including steam, condensate, drains, etc., will be designed by the architect-engineer selected for the overall plant design. Piping interfaces will be at the equipment flange, or at a flange at the enclosure wall, in the case of equipment housed in auxiliary packages. Interconnecting piping of components comprising the HRSG will also be designed by the A&E using the manufacturer's pipe connection location with an overlay of maintenance and access platforms, ladders and walkways.

The main steam and condensate piping interconnecting the HRSGs and the steam turbine will be installed in an elevated pipe run, the supporting structure of which is fabricated into the main turbine room enclosure structure. This piping will be grouped and cleanly run keeping turns and changes in elevation to a minimum and as required for flexibility and stress limitations.

Control valves and instrumentation will be located in areas of the piping having access from maintenance platforms. Piping and equipment drain valves will also be located in accessible areas. Where it is absolutely necessary to locate a drain over ducting, cable ways or other equipment, the drain piping will be routed so as to locate the valve at an accessible point and drain the fluid to an appropriate floor drain.

The final check on all piping design within the plant for compliance with OSHA regulations and interferences with other equipment and maintenance thereof, will be through the plant model. This model will be constructed from the design layout drawings and will include all piping and its interfaces. This procedure will forecast potential problem areas and permit changes prior to field construction.

All piping 2" and larger will be pre-fabricated and cleaned in the factory. A detailed procedure will be established to cover the cleaning and protection of the piping to ensure cleanliness of the pipe for final field installation.

SECTION 6
BALANCE OF PLANT

The balance of plant includes the primary cycle auxiliary mechanical equipment and supporting subsystems necessary for the operation of the plant. Included are the coal handling, receiving, storage, stacking, reclaiming, and crushing equipment; distillate fuel oil receiving storage and transfer equipment; heat rejection equipment including cooling towers, circulating equipment, and chemical treatment equipment; and a waste handling system providing for the collection and disposal of ash, storm water, and other plant wastes. Also included in the balance of plant section are subsections on the switchyard and structures and improvements.

6.1 COAL HANDLING

The primary fuel for the station is Illinois No. 6 Seam Marcoupin County BOM TP641 bituminous coal with an "as received" moisture content of 13 percent and a nominal size of 6 x 0 inches. The station full load heat balance calculation shows the total coal usage rate is 705,780 lbs/hr (353 tons/hr).

Based on a station capacity factor of 65 percent, a rail car capacity of 100 tons/car, an average train speed equal to 25 mph, the distance from the point of origin of the train (coal mine) to the station equal to 750 miles, coal loading and unloading times each equal to four hours maximum, and an average train down time of four (4) hours per round trip, the coal is transported to the site by two unit-trains of approximately 83 railroad cars each. During normal unit-train operation both trains arrive at the site once during each three (3) day period. Spare cars for the unit-trains are provided.

For unit-train operation, a loop track, thaw shed and unloading facility are provided at the site to assure continuous once-through operation. The loop track and the other major elements of the coal handling system are shown on the Plot Plan, Figure 7.0-1. Based on the relatively short haul distance assumption and the low annual coal usage, bottom dump coal unloading was selected over rotary-car dumping for the coal unloading facility. The thaw shed is provided for handling coal arriving in a frozen state.

Coal receiving, storage, stacking and reclaiming are described in Subsection 6.1.1. The equipment and coal storage areas for these services are shown on the Plot Plan, Figure 7.0-1. Also selected, based on the relatively low usage rate, are the radial boom stockpile conveyor with telescopic chute for stacking out the coal and the underground hoppers for reclaiming the coal from the live storage pile in lieu of a complex rail mounted stacker/reclaimer machine.

Subsection 6.1.2 describes coal crushing, transfer and storage. The equipment for these services are also shown on the Plot Plan, Figure 7.0-1. Not shown on the Plot Plan are the coal hoppers at the gasification systems. These hoppers are the final coal storage point prior to pretreatment and gasification and are shown on the Plant Island General Arrangement and Elevation Drawings, Figures 7.0-3 and 7.0-2 respectively. Beyond thawing at delivery and crushing to a nominal size of 1/4 x 0 inches, no other coal pretreatment is provided in the coal handling system prior to delivery to the coal hoppers.

6.1.1 Coal Receiving, Stacking, Storage And Reclaiming

As described, coal is delivered to the plant by unit-trains, where it is unloaded into a receiving hopper, transported on Conveyor No. 1 to the Stacker Tower, and either stacked out to the live storage pile on Conveyor No. 2 or transported on Conveyor No. 4 directly to the Crusher Tower.

The coal receiving hopper has a storage capacity of 200 tons and is able to receive and handle precrushed 6 inch x 0 nominal size coal. The coal is fed from the hopper through feeders onto Conveyor No. 1 at a maximum feed rate equal to the estimated maximum coal delivery rate, based on assumptions in Subsection 6.1. Conveyor No. 1 transports the coal to the stacker tower surge bin and is equipped with a belt scale for continuous weighing and recording of coal quantities delivered to the station, and a metal detector.

From the stacker tower surge bin, coal is normally fed onto Conveyor No. 2, the radial boom stockpile conveyor with telescopic chute, to be stacked out to the live storage pile. Conveyor No. 2 has a maximum feed rate equal to the maximum feed rate of Conveyor No. 1. From the stacker tower surge bin coal can also be fed onto Conveyor No. 4 for transport directly to the crusher tower.

The live coal storage pile is sized to supply the normal plant operating coal requirements between unit-train deliveries and equals approximately the equivalent of three average unit-train deliveries or three days full-load station operation. Adjacent to and south of the live coal storage pile is the dead coal storage pile. The dead coal storage pile provides the coal supply for the plant during disruptions of normal unit-train delivery and equals approximately the equivalent of 60 days station operation at a 65 percent capacity factor.

Coal reclaiming equipment includes the stacker tower, live coal storage pile, Conveyors Nos. 3 and 4 and the crusher tower. During normal station operation, coal is fed by feeders from the live storage pile onto Conveyor No. 3 and transported to the crusher tower. Conveyor No. 3 is rated at twice the full load plant firing rate to allow scheduled down time for equipment maintenance. During abnormal conditions when there is insufficient coal supply in the live coal storage pile and a unit-train is delivering coal, coal can be transported directly from the stacker tower to the crusher tower on Conveyor

No. 4, which is rated at the full-load plant firing rate. When Conveyor No. 4 is in operation all coal not fed to Conveyor No. 4 is fed to and stacked out to the live storage pile on Conveyor No. 2.

During periods of abnormal operation when Conveyor No. 3 is out of service, when there is insufficient coal supply in the live coal storage pile, or when coal is not being delivered to the plant and transported directly to the crusher tower by Conveyor No. 4, coal can be reclaimed using the emergency reclaim hopper. Coal is moved by bulldozer from the live or dead coal storage piles to the emergency reclaim hopper, fed unto Conveyor No. 5 and transported to the crusher tower at rates up to the full-load plant firing rate.

Both coal storage piles are managed by bulldozers. Dust removal and suppression equipment is provided at all transfer points. Vacuum cleaning equipment is provided at selected locations. A water spray fire protection system is provided. The coal handling system is designed for automatic operation, with the main coal handling system control panel located in the main plant control room and local controls provided at selected points.

6.1.2 Coal Crushing And Transfer

Coal is supplied to the crusher tower, crushed, transported on either Conveyor 6A or 6B to the transfer tower, and then transported to the coal bins at the gasification system areas on either Conveyor 7A or 7B. The coal is transported to the crusher tower surge bin on Conveyor Nos. 3, 4 or 5. From the surge bin, coal is fed by feeders into one of the two crushers where it is crushed to a 1/4 inch x 0 nominal size. The crushed coal is then discharged from the crusher onto either Conveyor No. 6A or 6B. Each crusher and Conveyors 6A and 6B are sized for twice the full load plant firing rate, providing redundancy in case of equipment malfunction and scheduled down time for equipment maintenance.

Covered Conveyors 6A and 6B supply the crushed coal to the transfer tower surge bin. Feeders from the transfer tower surge bin feed coal onto either tripper Conveyor 7A or 7B which supply the coal to the coal bins at the gasification areas. Conveyor 7A or 7B are each sized for a maximum of twice the full load plant firing rate, providing redundancy in case of equipment malfunction and scheduled down time for equipment maintenance. The coal bins at the gasification areas are sized for four hours full load station operation.

Coal receiving, stacking, storage and reclaiming system, dust removal and suppression equipment, vacuum cleaning equipment, fire protection equipment, and controls are provided and are similar to the equipment described in Subsection 6.1.1.

6.2 STARTUP AND/OR STANDBY FUEL SYSTEM

A No. 2 distillate fuel oil system is provided for the startup and shut-down requirements of the gas turbines; for auxiliary boiler and diesel engine-driven equipment; for gas turbine operation (abnormal operating conditions) when the gasification systems are down for maintenance; and during initial plant operation prior to completing construction of the gasification systems.

The system includes equipment for unloading fuel oil from rail tank cars and tank trucks. The unloading facility is located between the loop track and the passing track, allowing for the unloading and storage of fuel oil tank cars without interfering with the normal delivery of coal. Three (3) hose stations are provided for rail unloading, allowing three (3) 23,000 gallon tank cars to be unloaded simultaneously without shifting. Two (2) pumps are provided for fuel unloading and transfer. In addition to the rail tank car unloading equipment, a separate unloading station is provided for tank trucks within the same facility. Two (2) additional pumps are provided for this service.

The oil storage facilities consist of two (2) 143,200 barrel capacity storage tanks located inside diked areas. The oil storage is equivalent to ten (10) days station operation at a 75 percent capacity factor. Two (2) fuel forwarding skids discharge the fuel oil to the gas turbine fuel skids, the auxiliary boiler day tank, and other small day tanks. All piping is underground and recirculation lines returning to the storage tanks are provided.

6.3 COOLING WATER SYSTEMS

Closed-loop type cooling water systems are used at the station for condensing the exhaust steam from the steam turbine, for cooling equipment, and for cooling other cycle fluid streams. The collected heat is rejected to the atmosphere by evaporative type cooling towers. The major portion of the cooling load is the condensing of the exhaust steam from the steam turbine by the main circulating water system. The cooling of equipment and other cycle fluid streams is done independently of the main circulating water system by the auxiliary cooling water system.

The primary source for the plant cooling water supply is the North River, assumed to be a tributary of the Mississippi-Missouri River Basin. For design purposes in this study, the assumed river water analysis from the ECAS study was used (see OPDD Low-Btu Combined Cycle Electric Power Power Plant Report). The ECAS study, Subsection 6.4, water analyis made identical assumptions for the source of the plant cooling water supply.

The North River water is pumped into the Clean Water Holding Pond by three 50 percent capacity river intake pumps. The pond provides storage and clarification of the river water for cooling tower makeup and other station supplies. As part of the pretreatment facility, the pond capacity is sufficient to accomplish initial sedimentation and removal of the bulk and suspended solids from the river water. As part of the site general water management system, the pond receives treated water from the Storm Water and Wastes Holding Pond.

6.3.1 Main Circulating Water System

The main circulating water system is designed to condense the exhaust steam from the steam turbine and consists of a cooling tower and basin, circulating water pumps, main condenser and circulating water piping. The cooling tower serving the main circulating water system is an eight cell induced mechanical draft, double cross flow, evaporative (wet) design. The tower is orientated parallel to the predominant wind direction and all cells are in line and mounted at ground level over a common cast-in-place concrete basin. Each cell has a propeller fan located in its exhaust stack and is driven through a speed reducer by an electric motor. The tower is sized to reject 2150 x 10^6 Btu/hr by evaporation and convection, based on an ambient dry bulb temperature of 59°F with a 60 percent relative humidity, which corresponds to a wet bulb temperature of 51.4°F. The heat rejected is the main circulating water system total at the ISO ambient conditions. The total water flow is 220,000 gpm.

The water is circulated from the cooling tower basin, through the main condenser and back to the flow distribution deck of the tower by two (2) 50 percent capacity circulating water pumps. The pump wet well is separated from the tower basin by removable screens, preventing collected debris that have been washed from the air passing through the tower from entering into the main circulating water system. The concentration of dissolved salts in the water is limited by tower water blowdown to the river from the pump wet well. The 102 inch circulating water pipe, which loops from the cooling tower to the condenser at the steam turbine-generator is a reinforced concrete water pipe, steel cylinder type.

Tower water makeup to replace that lost from the cycle due to evaporation, blowdown, drift, carry-over and leakage comes from the Clean Water Holding Pond. The required 8600 gpm of makeup water flows by gravity to the cooling tower basin and is acid treated and chlorinated at the tower. The acid feed equipment is used for the reduction of calcium alkalinity in the cooling tower water and is controlled to maintain the pH of the circulating water in the tower within a pH range of 6.9 to 7.5. Chlorination equipment is provided for shock chlorination of the cooling tower water in order to retard the growth of slime, algae and other forms of aquatic life on tower surfaces and on the cooling water side of the main condenser, pumps and piping.

6.3.2 Auxiliary Cooling Water

The auxiliary cooling water system includes a cooling tower and basin, four (4) 25 percent capacity auxiliary cooling water pumps and piping.

The auxiliary cooling water pumps are installed on a deck above the basin wet wall. The wet wall is separated from the tower basin by removable screens, protecting the pumps from any foreign material entrapped in the basin and preventing this material from entering the auxiliary cooling water system. The pumps furnish cooling water to the various coolers in the power blocks, steam turbine area and the gasification systems, as well as other miscellaneous heat exchangers throughout the station. The auxiliary cooling water is supplied and returned via two 42" buried steel pipes.

The cooling tower serving the auxiliary cooling water system is a four cell tower, identical to the tower described in Section 6.3.1 of this Report. The tower is sized to reject 820 x 10^6 Btu/hr by evaporation and convection. Water treatment for the auxiliary cooling water system is identical to that described for the main circulating water system in Subsection 6.3.1 of this Report.

6.4 SWITCHYARD

The switchyard is located to the north of the station, as shown on the Plot Plan, Figure 7.0-1, (see Section 7 of this Report), to facilitate easy access to the transmission lines feeding Middletown, USA, and surrounding areas.

The output of the station is fed through the five (5) main transformers where it is stepped up to 161 kv and delivered to the station switchyard. The switchyard design utilizes a breaker-and-a-half scheme. The switchyard includes two (2) outgoing lines which feed transformers which step up the switchyard voltage to a 500 kv transmission voltage. Six (6) overhead 161 kv lines are provided from the switchyard to the on-site station distribution system, one (1) line to each generator main transformer and a line to the startup transformer.

The switchyard is protected from lightning and switching surges by lightning and surge protection equipment and by overhead electrostatic shield wires. The breaker-and-a-half switching arrangement in the switchyard includes two (2) full capacity main buses. Primary and backup relaying are provided for each circuit along with circuit breaker failure backup protection. All necessary equipment for monitoring, relaying, operation and control of the switchyard equipment is provided.

6.5 WASTE HANDLING, STORAGE AND REMOVAL

The waste handling and storage at the station is designed to provide the maximum containment and reuse possible so as to comply with regulations protecting the environment. The solid waste is primarily the ash resulting from the coal gasification process and amounts to approximately 1000 tons per day when the station is at full capacity. The ash is collected in bins located at the process and then trucked to an on-site storage area. Storm water runoff from the ash storage area and other areas where the water could become contaminated is collected in the Storm Water and Wastes Holding Pond. Here, the storm water is mixed with other station liquid wastes before being clarified and treated for reuse as part of the station water supply. The primary use of the water is for makeup to the evaporative type cooling towers. The only waste leaving the site is molton elemental sulfur from the gasification process. The sulfur storage, handling and removal is described in Subsection 6.5.2, but may not actually be considered a waste product as it is potentially saleable in its elemental form.

6.5.1 Solid Wastes

The solid wastes produced by the station are:

1. the ash from the gasifiers
2. ash from the incinerator at the Process Water Treater Plant
3. any suspended solids settling out of the water in the two site ponds.

The eight (8) station gasifiers produce a total of 80,431 lbs/hr of agglomerated ash at full-load operation. This ash results primarily from the ash content of the coal plus pyrites, unbound carbon and sulfur.

Each of the gasification systems has its own ash handling system. The agglomerated ash with water at $140^{\circ}F$ is periodically dumped from the ash lock-hoppers into a common ash-hopper. The ash-hopper is located in a pit with its cover at grade level and has sufficient volume to hold 100 tons of coal at a density of 50 pounds per cubic foot. This provides space for more than one hour's inventory of coal from the two (2) gasifiers and pretreaters when the gasification system is shut down to either the "cold-ready-to-start" or "cold-stand-by" modes, in case of an ash handling system failure.

In order to achieve the storage volume of a long hopper with only two (2) receiving points, screw conveyors are positioned on the hopper centerline just below the cover and are run only when ash or coal must be stored in the hopper. Otherwise, the ash drops straight through to the hopper outlet gates and onto the ash disposal system drag conveyor. The screw conveyors act as leveling or distribution conveyors by moving the ash or coal towards the center of the hopper. To convey the stored material from the center of the hopper back to the hopper outlet gates, screw conveyors are positioned in the bottom of the hopper trough section.

The hopper is equipped with outlet slide gates, positioned directly beneath the ash disposal pipes from the lock hoppers. During normal operation the ash and water drop straight down onto the drag conveyor running beneath the gates and on the center-line of the ash-hopper. A water level is maintained in the conveyor casing at about half full and excess water overflows into the water circulating pump wetwell. Each conveyor is sized for twice the expected ash production rate.

The ash is discharged from the drag conveyor aboveground into a receiving hopper for the bucket elevator. Free water drains back from the conveyor so that entrained water leaving with the ash is approximately 15 percent by weight. The bucket elevator with rappers, positioned at the side of the ash bin, carries the ash from grade level to a discharge point above the top of the bin. A chute conveys the dumped ash to the center of the ash bin and a diverting gate permits the isolation of each ash bin by directing the ash onto a horizontal screw conveyor which conveys it into the adjacent bin.

Each Gasification System ash bin is sized to store 650 tons of ash at a density of 90 pounds per cubic foot. This provides ash storage for 64 hours of full load operation, allowing for two (2) day shut-downs of the ash disposal operation. Each bin has drainage features allowing any free water to drain back to the drag conveyor water circulating pump wetwell. The outlet of each bin is equipped with a gate and chute for filling trailer trucks, operated through a local controller by the truck operator.

The ash is transported from the ash bins to the on-site ash storage area by three (3) trailer trucks. The three truck operation is based on one shift per day (7 hours), five (5) days per week, at a station capacity factor of 65 percent. A greater capacity factor or a truck outage for maintenance would require either second shift duty or six (6) or seven (7) day per week operation.

The ash from the incinerator at the Process Water Treater Plant equals 600 lbs/hr. The ash is simply conveyed from the incerator into an ash storage bin for truck removal. One trailer truck disposes of the ash to the on-site ash storage area approximately once every two days.

The Clean Water Holding Pond is of sufficient capacity to provide for the settling of suspended solids found in the river water makeup to the pond. The Storm Water and Waste Holding Pond is also sized to allow for the settling of suspended solids found in the storm water runoff, underflow wastes from the station clarifiers and the plant floor drains. It may be necessary at times to dredge these ponds to their original depths, thereby restoring their original storage volumes and retention times. The dredged material can be trucked to either the ash storage area or, if desired, to other on-site fill areas.

The ash storage area is sized to store the 30-year accumulation of ash and other solid wastes at full load plant operation at a 65 percent capacity factor. The ash storage area is located south of the coal handling and storage area and site preparation including grading, embankments, and roadways are planned to permit continuous solids disposal operations.

6.5.2 Liquid Wastes

Liquid wastes result primarily from:

1. the treatment and demineralizing of station makeup water

2. water collected by the station floor drains and equipment drains

3. boiler blowdown water

4. process waste water from the gasification systems

5. molten elemental sulfur.

Areas subject to oil spills are isolated by curbing, and these areas are drained by a separate drainage system from the regular station floor drain system. The oil drains are collected in a sump and then pumped to an API oil/water separator which is part of the Process Water Treater Plant for the gasification systems.

The underflow waste from the clarifiers and the backwash waste from the water treatment filters and demineralizers are collected in sumps near the Water Treatment Building and Chemical Treatment Building. From these sumps the waste water is then pumped to the Storm Water and Wastes Holding Pond.

Boiler blowoff and blowdown are piped to blowoff tanks where they are cooled before draining to the house sump. The blowoff and blowdown are then combined with the station floor and equipment drains, also collected in the house sump, and pumped to the Storm Water and Waste Holding Pond.

The majority of the process waste water from the gasification Process Water Treater Plant is pumped to the Storm Water and Waste Holding Pond. The remainder of the water is used as makeup for ash quenching in the gasifier ash quench and lock hoppers.

Contaminated storm runoff water from the gasification system areas, lock-gas system area, Selexol and scrubber areas, Claus plants and their associated sulfur storage areas, stripper and waste water treatment area, future tail-gas treater area, coal handling and storage areas, fuel oil handling and storage areas, and ash handling and storage areas are all collected in the Storm Water and Waste Holding Pond. Here, the storm water is combined with the other station liquid waste described above and mixing, dilution, neutralization and settling of suspended solids can occur. The water is then clarified and treated in the clarifier and Chemical Treatment Building before being pumped to the Clean Water Holding Pond for reuse as station water supply.

The molten elemental sulfur is collected, stored and maintained at 280°F in a pit adjacent to each Claus plant. The two pits have a combined storage capacity of five (5) days full load plant operation. From the pits the sulfur is pumped into railroad tank cars or trucks for off-site resale or disposal.

6.6 STRUCTURES AND IMPROVEMENTS

6.6.1 Station Building

The 750 foot long x 108 foot wide x 90 foot high steel frame station building is shown on the Plant Island General Arrangement and Elevation Drawings, Figures 7.0-3 and 7.0-2 respectively. The building houses the four (4) gas turbine-generator units, the steam turbine generator unit, condenser, and the auxiliaries for these units.

The steam turbine-generator is supported on a concrete pedestal located on the operating floor in the center of the building, between the four (4) gas turbines. The structural steel and reinforced concrete slab operating floor is 25 feet above grade. A partial mezzanine level is provided below the operating floor for access to the gland steam condenser, air ejectors and other auxiliary equipment. Below the mezzanine floor level and located at grade level are the condenser, feedwater heater, condensate pumps, and other auxiliary equipment for the steam turbine-generator.

A 75 ton bridge crane with auxiliary hook runs east-west the length of the building, above the steam turbine-generator and gas turbines. The bridge crane is capable of lifting the heaviest turbine-generator part exclusive of the stator. Adequate laydown area is provided between the gas turbines on the ground floor, at the east end of the station building on the ground floor, and on either side of the steam turbine-generator on the operating floor. The railroad track extending into the east end of the station building is provided for delivery or removal of large parts and equipment. A hatch is provided in the center of the operating floor north of the steam turbine to facilitate the handling of equipment.

Open stairways are provided, running from the ground floor to the operating floor, at both the southeast and southwest corners of the operating floor.

Adequate entrance and egress is provided through man doors located on all sides of the station building. Two (2) roll-up doors are provided on the east end of the building. One door provides for entrance of a railroad car into the station building and the second door adjacent to it is for truck use. In addition, two (2) roll-up doors are provided on the south side of the station building and one (1) roll-up door is provided on the north side.

The station building is enclosed with insulated, corrugated aluminum siding. Forced air ventilation is provided by means of a central supply air system and exhausted by propeller type fans and roof ventilation.

6.6.2 Control Building

Adjacent to and south of the steam turbine area of the station building is the three-level steel frame control building, shown on the Plant Island General Arrangement and Elevation Drawings, Figures 7.0-3 and 7.0-2. The control room is located at the operating floor level and includes the necessary control panels; and space for offices, storage, kitchenette, and toilet facilities. The roof and operating floor level are extended northward and framed to the station building. Access and egress is through man doors at the operating floor level to the steam turbine-generator area, and to the pipe/cable rack and walkway by means of doors on the East and West sides of the control building. Within the control building, a stairwell runs from the ground floor to the control room level.

The cable spreading room is located at the mezzanine level below the control room. Access and egress is provided by the stairwell within the building.

The electronics room is located at the ground floor level below the cable spreading room. Access is provided through man doors to the control building exterior and by the stairwell within the building.

A 2000 lb. capacity elevator, traveling at 150 feet per minute, is located in the southwest corner of the control building. This serves all levels as both a personnel and freight elevator. The control room, and electronics room are both air conditioned. The control building is enclosed with insulated corrugated aluminum siding.

6.6.3 Pipe/Cable Rack And Walkway

Running East-West along the South side of the station building and branching southward by the heat recovery steam generators and through the centers of the gasification areas, as shown in the Plant Island General Arrangement Drawing (Figure 7.0-3), is a combination pipe/cable rack and walkway. The primary purpose of this structure is to provide support for various pipes and cables. The structure also provides access to each of the heat recovery steam generators and the gasification areas. The combination rack/walkway is a vertically and horizontally braced steel structure ten (10) feet wide with grating walkway stairs provided at a number of locations.

6.6.4 Service And Warehouse Buildings

The steel frame service and shop building is located east of the station building, as shown on the Plot Plan (Figure 7.0-1). The building is 120 foot long x 60 foot wide x 30 foot high. The building houses the machine shop, electrical shop, welding area, tool rooms, storage areas, and maintenance offices. A 120 foot long x 60 foot wide x 30 foot high steel frame warehouse is located just south of the service and shop building. Both buildings are enclosed with insulated aluminum exterior siding; provided with pendant operated bridge cranes, for heavy lifts and ease of equipment handling; the necessary heating and ventilation equipment; and all offices are air conditioned.

6.6.5 Administration And Office Building

Shown on the Plot Plan (Figure 7.0-1), east of the service building, is a 100 foot x 50 foot two story steel frame administration and office building. This building provides space for plant supervisory personnel including the superintendent and engineering, purchasing and accounting personnel. A lunch room and a locker room complete with lavatories and showers are also contained in this building. Insulated, corrugated aluminum siding encloses this building. The necessary building heating, ventilating, and air conditioning is included.

6.6.6 Water Treatment Building

A 100 foot x 60 foot two (2) story steel frame water treatment building of insulated aluminum siding, containing an air conditioned water treatment laboratory, demineralizing and chemical facilities, toilet with locker facilities and space for miscellaneous storage is provided. This building along with its associated clarifier and chemical storage tanks is located to the west of the station building and south of the clean water holding pond, as shown on the Plot Plan (Figure 7.0-1).

6.6.7 Chemical Treatment Buildings

There are two (2) chemical treatment buildings on the site. One chemical treatment building is located near the cooling towers, and the other just North of the storm water and wastes holding pond. Each of these buildings is steel frame, 60 foot x 30 foot, and enclosed with insulated aluminum siding. Both buildings are shown on the Plot Plan.

6.6.8 Intake Structure

A reinforced concrete intake structure is located at the river bank just west of the clean water holding pond, as shown on the Plot Plan. The river water pumped through the structure provides make-up to the clean water holding pond. Enclosed by the structure are trash racks, traveling water screens, stoplogs and river intake pumps. The invert elevation of the structure is at a depth sufficient to maintain suitable submergence on the river intake pumps.

6.6.9 Coal Handling Structures

Located on the coal pile loop-track is a steel frame coal car thaw shed. The heating coils housed in this aluminum sided shed thaw any frost or ice present in the delivered coal. West of the thaw shed is a reinforced concrete, bottom dump unloader. After being dumped, the coal is conveyed to a telescopic type stacker chute. A reinforced concrete hopper reclaims the coal to a conveyor which delivers the coal to a crusher tower. Following crushing the coal is conveyed through a transfer tower to the lock hoppers at the gasification system areas. Details of the coal handling system are included in Subsections 6.1, 6.1.1, and 6.1.2 of the OPDD Low-Btu Combined Cycle Electric Power Plant Report, and shown on the Plot Plan (Figure 7.0-1).

6.6.10 Gasification Subsystem Structures

Steel tower type structures, rising to an elevation approximately 200 feet above grade, are provided for support of the various gasification subsystem equipment in each gasification subsystem area. Platforms for access to the coal bins, coal lock hoppers, cyclones, pretreaters, gasifiers, ash lock hoppers, steam drums, process waste heat boilers, and ash cooling hoppers are provided within the tower structure.

In the gas purification (Selexol and Scrubber) and Claus plant areas, smaller steel structures are provided for support of various equipment.

6.6.11 Stack And Stack Support

A coated steel stack extension approximately sixteen (16) feet in diameter and reaching a maximum height of approximately 300 feet is provided to carry the heat recovery steam generator (HRSG) exhaust gases above the nearby gasifier towers and coal handling equipment. These stacks are sized for an exit velocity of 90 feet per second. The vertical load for the transition section and stack is carried by the support steel provided.

6.6.12 Foundations And Trenches

Due to the presence of limestone bedrock at a depth of eight (8) feet the foundations for all plant island structures, including steam and gas turbines, heat recovery steam generators, gasification subsystems, lock gas systems, purification subsystems, Claus plants, sulfur storage areas, and wastewater treatment areas are supported on spread footings. The gas turbine-generators are supported by monolithic foundations. The steam turbine-generator is supported on a reinforced concrete pedestal. The station building and other major equipment are supported by individual footings. Ground floor slabs are soil supported. Trenches containing the ash waste conveyors run below the gasification subsystems. Details of the ash handling system are included in Subsections 6.2 and 6.2.1 of The OPDD Low-Btu Combined Cycle Electric Power Plant Report.

6.6.13 Concrete

The station building foundations, major equipment foundations, concrete paving, turbine pedestal, and all other concrete structures are designed as required by loads and soil conditions, and in accordance with the American Concrete Institute specifications. In general, 3000 psi concrete is used for these structures.

6.6.14 Steel

All structural steel is designed in accordance with specifications of the American Institute of Steel Construction. Wind bracing is designed for a basic wind zone of 25 psf adjusted for height. Connections are welded, and field connections high strength bolted. Generally, structural steel is cleaned by commercial sandblasting and shop primed with one coat of zinc-chromate primer. Field painting consists of two (2) finish coats.

6.7 AUXILIARY BOILER

An auxiliary boiler is provided to supply the essential steam requirements to the auxiliary steam header for gasifier startup; steam turbine startup; maintaining the steam turbine at a temperature level consistent with rapid startup; maintaining sulfur in the sulfur storage area in a molten state; the building heating system; and freeze protection of the piping and equipment during outages. The auxiliary boiler is an oil-fired unit with rated operating conditions of 100,000 lbs/hr, 150 psig, and 550°F. Feedwater for the boiler is supplied by one motor-driven auxiliary boiler feedwater pump which takes suction from the storage tank beneath the auxiliary boiler deaerator. A motor-driven auxiliary boiler condensate supply pump furnishes condensate to the deaerator, taking suction from the condensate storage tank. Steam supply for the deaerator is from the auxiliary steam header.

The auxiliary boiler is located on the South side of and near the center of the station building at grade level. The associated auxiliary boiler deaerator with storage tank is elevated adjacent to the east wall of the control building at the walkway level of the pipe/cable rack and walkway. At grade level are the feedwater pump below the deaerator, and condensate pump adjacent to the condensate storage tanks.

Chemical feed equipment for the auxiliary boiler feedwater system is similar to the equipment supplied for the main condensate and feedwater cycle.

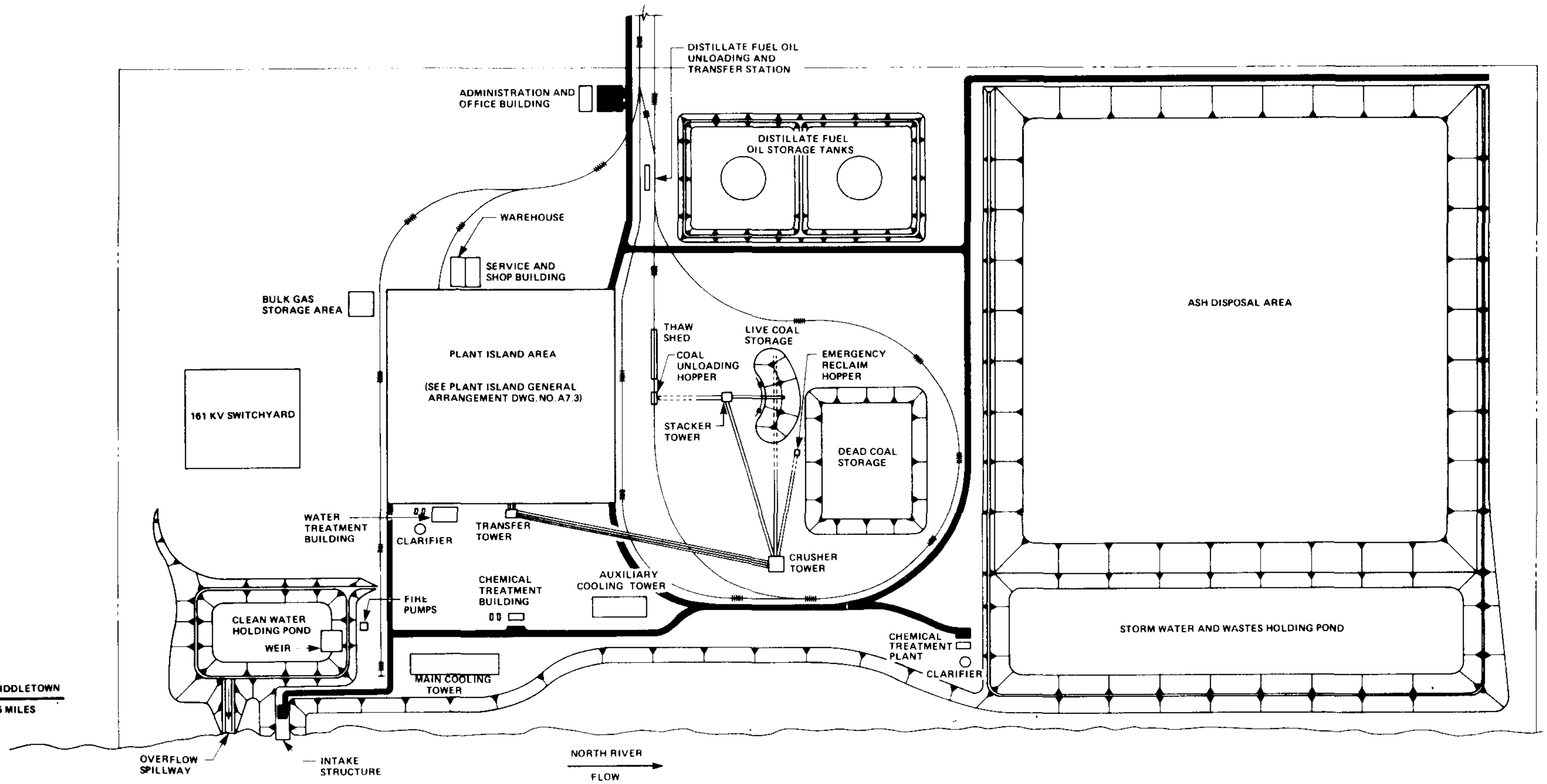
SECTION 7
SITE PLAN

The Middletown site described in WASH 1230 Section 2 modified to reflect fossil-fuel plant siting is used for the combined cycle gas/steam turbine with integrated LBTU gasification. This site is located on the east bank of the North River, 25 miles south of Middletown, U.S.A. The site is a flood plain approximately 2600 feet wide running easterly from the river to hills whose elevations vary from 150 feet to 200 feet above mean river level. Beyond this area, the topography is gently rolling hills with no major topographical features.

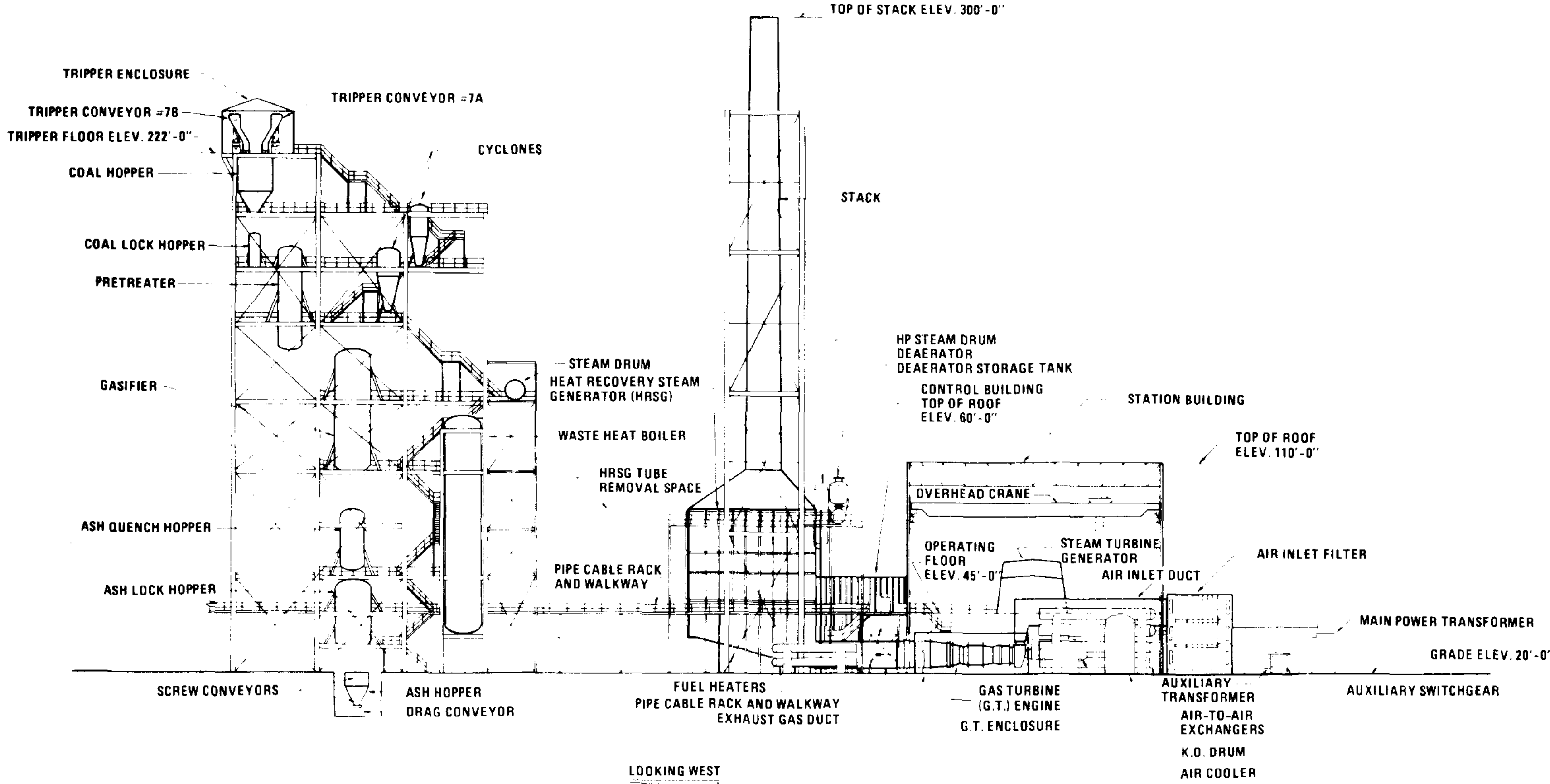
The North River is approximately a half-mile wide with a 100 year maximum level of eight (8) feet above mean level which is taken as zero elevation.

The actual land requirement for the station, exclusive of the access track right-of-way, is 335 acres. Shown on the Plot Plan, Figure 7.0-1, is the plant island area, switchyard, clean water holding pond, cooling towers, coal handling and storage area, ash storage area, distillate fuel oil handling and storage area, storm water and wastes holding pond, and all major station buildings excluding those in the plant island area. Also shown are railroad and roadway systems entering the station from the east. The grade elevation for the station area is approximately twenty (20) feet above mean river level, with the necessary diking and grading indicated. The Plot Plan was developed by locating the switchyard on the north side of the plant in the direction of the major user of electricity; and developing a compact arrangement for the coal, ash, cooling tower and pond areas in relation to the plant island. Details of the Plot Plan are described in Subsection 7.2 of the OPDD Low-Btu Combined Cycle Electric Power Plant Report.

The plant island general arrangement is shown on Figure 7.0-2 and is further described in Subsection 7.3 of the OPDD Low-Btu Combined Cycle Electric Power Plant Report. The arrangement drawing shows the main power transformers with their associated auxiliary switchgear, transformers, and circuit breakers; the station building; the heat recovery steam generators; the control building; the ash handling areas; the gasification systems and the associated lock gas system; the Selexol and scrubber areas; the Claus plants and their associated sulfur storage areas; the future tail gas treater area; the stripper and waste water treatment area; and the chemical storage, laboratory and warehouse building. For Phase I of this study the arrangement of the buildings and equipment was based on locating the various components in order to produce a compact plant island while providing space for maintenance, having a single



COMBINED CYCLE GAS TURBINE SYSTEM WITH INTEGRATED LOW-BTU GASIFICATION — PLOT PLAN
Figure 7.0-1



COMBINED CYCLE GAS TURBINE SYSTEM WITH INTEGRATED LOW-BTU GASIFICATION – ELEVATION

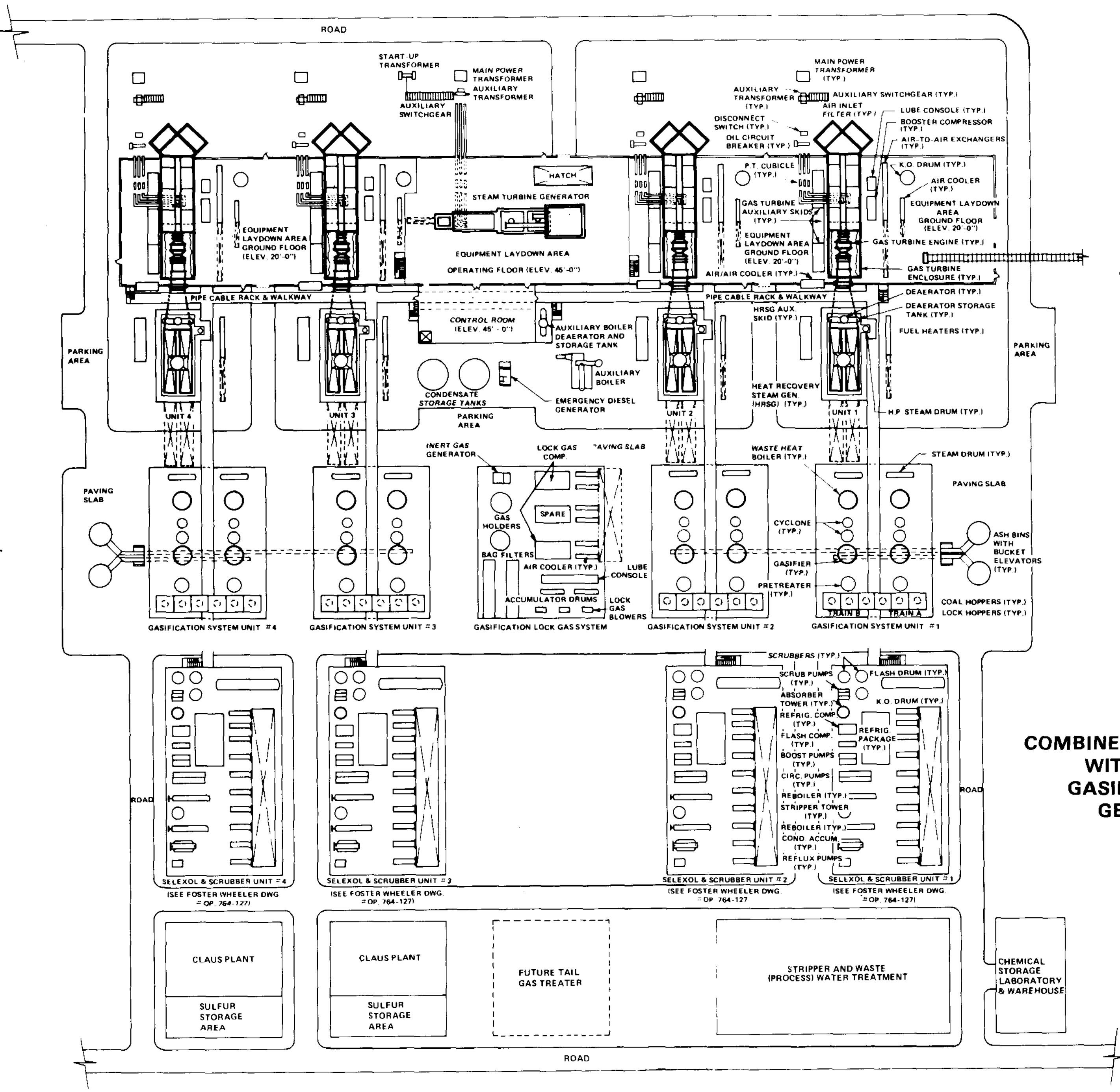
Figure 7.0-2

station building as small as possible, maintaining a clear direct path from the electric generators to the switchyard, and minimizing the lengths of the major piping systems. The arrangement also attempts to maximize the same handedness of units for ease of design and construction while being symmetrical about the steam turbine, in order to keep major steam piping system lengths equidistant. In order to further optimize the plant island arrangement detailed cost evaluations of a variety of arrangement options will be made in Phase II.

The plant Elevation, Figure 7.0-3, corresponds to the Plant Island General Arrangement Drawing and shows a view of the plant looking west from a section line located between the Unit No. 1 and No. 2 gas turbine-generators and gasification systems. The view extends from the main transformers on the north side of the plant island up to and including the south end of the gasification system, and includes all major equipment and the station building. Not shown on the elevation, to the south of the gasification system, are the Selexol and scrubber, and stripper and waste water treatment areas. The Elevation is further described in Subsection 7.4 of the OPDD Low-Btu Combined Cycle Electric Power Plant Report.

7.1 SITE SELECTION

The Middletown site was selected for its ideal characteristic features. The site is situated near a major user of generated power and is of suitable size for a large generating station. The site has access to major and secondary roadways, a major railroad and river water supply. The natural flood plain is such that it was incorporated into the site grading with the major structures located approximately 800 feet from the river at a grade elevation of 20 feet above the mean river level. The site has no major features which would require an above average development effort.



COMBINED CYCLE GAS TURBINE SYSTEM WITH INTEGRATED LOW-BTU GASIFICATION – PLANT ISLAND GENERAL ARRANGEMENT

Figure 7.0-3

SECTION 8
ELECTRICAL SYSTEM

The plant electrical system for the reference design is defined on Figure 8.0-1 and discussed in this section. The system is representative of current Westinghouse PACE practice and conventional power plant design.

8.1 UNIT HV ELECTRICAL

8.1.1 Generators

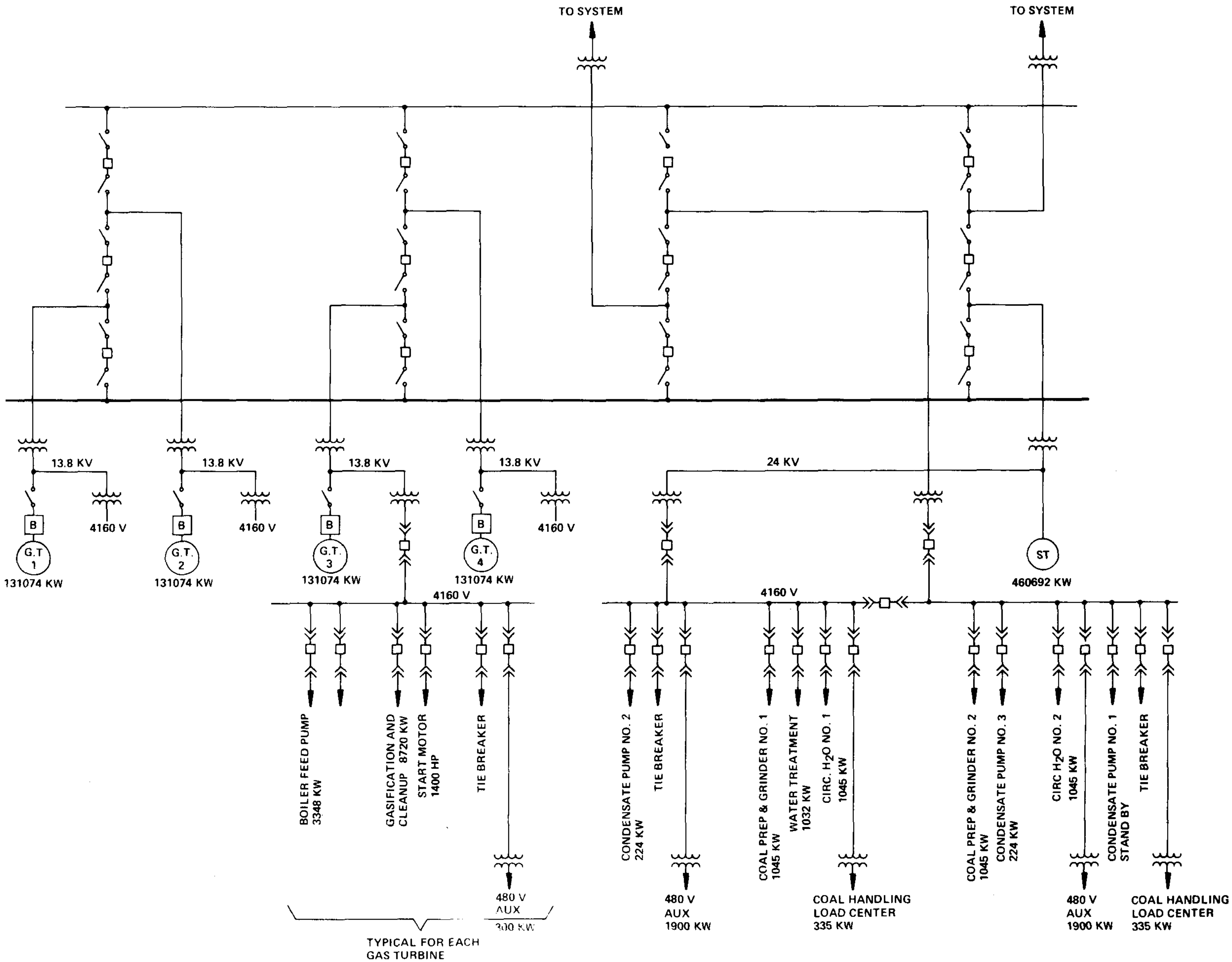
The station's four (4) gas turbine generators are each rated 131 MW, 0.9 pf, 3-phase, 60 Hz, 13.8 kv, 3600 rpm and the steam turbine generator rated 461 MW, 0.9 pf, 3-phase, 60 Hz, 24 Kv, 3600 rpm; hydrogen-cooled stator and rotor. The generator exciters are direct connected, enclosed, air-cooled with permanent magnet generator. The generators are wye connected with the neutral point grounded through distribution type transformer and secondary resistor.

8.1.2 Generator Bus And Oil Circuit Breaker

The generator power output to the main and auxiliary transformers is fed through the generator bus. The generator bus is a metal enclosed isolated phase type rated for the maximum expected output, 105°C (65°C rise over 40°C ambient) with taps to the instrument transformers provided. The gas turbine generator bus has a voltage and withstand rating of 14.4 kv, 110 kv BIL; the steam turbine generator is rated 24 kv, 150 kv BIL. Neutral grounding equipment and surge protection equipment are also to be provided.

The potential transformers consist of two (2) sets of three (3) disconnecting potential transformers current limiting fused with each set in a separate compartment. The potential transformers on the gas turbine generator buses are rated 14,400/120 Y, 120:1 ratio and those on the steam turbine generator bus are rated 24,000/120-72 Y, 200-120:1 ratio. The surge protection equipment consists of three (3) surge arrestors and capacitors rated 15 kv and 19.5 kv.

The neutral grounding equipment located on the gas turbine generator consists of a single-phase, 60 Hz transformer rated 12 kv/240-120V and a grounding resistor, grid-type, 240 volts continuous.



PLANT ELECTRICAL SYSTEM DIAGRAM
Figure 8.0-1

The neutral grounding equipment of the steam turbine generator consists of a single-phase transformer, 14.4 kv/120-240V, and a grounding resistor, grid-type, 240V continuous.

The oil circuit breakers on the gas turbine generator bus are located outdoors and rated 14 kv, 6200 amps, 1500 MVA. The oil breakers are provided on each generator output for synchronizing and isolating the unit.

8.1.3 Main Transformers

Power from the station generation units is delivered to the 161 kv switchyard through the main transformers, one associated with each generation unit. The main transformers are rated for maximum expected output of the associated generation unit less the auxiliary load and kva losses of the transformer.

Each gas turbine main transformer is rated 90/120/150 MVA, 13.8/161 kv, OA/FOA/FOA, 65°C rise. The steam turbine main transformer is rated 500 MVA, 24/161 kv, FOA, 65°C rise. The low voltage windings of each transformer are delta-connected and the 161 kv high voltage windings are wye-connected with the neutral solidly grounded. Each transformer is provided with a sudden pressure relay that will trip the unit on relay operation. To supply cooling power to these units, two auxiliary power supplies are provided for each transformer, with automatic transfer in the event of loss of normal cooling power supply.

8.2 UNIT 5 KV ELECTRICAL

8.2.1 Auxiliary Transformers

During normal operation of the station, the auxiliary transformer connected to the bus of each generator provides the normal source of electrical power for the station auxiliaries. During startup of the station, the auxiliary transformers associated with the gas turbine generator units normally provide the startup electrical power requirements of the gas turbine auxiliaries. The gas turbine auxiliary transformers are each rated 15/20 MVA, 13.8/4.16 kv, OA/FA. The primary windings of these units are delta-connected and the 4.16 kv secondaries are wye-connected with the neutral low resistance grounded. The steam turbine auxiliary transformer is rated at 10/12.5 MVA 24/4.16 kv, OA/FA. The primary windings of these units are delta-connected and the 4.16 kv secondaries are wye-connected with the neutral low resistance grounded. The auxiliary transformers are provided with sudden pressure relay protection and a cooling power supply similar to that of the main transformer.

8.2.2 Station Startup and Customer's Auxiliary Transformer

The station startup transformer is sized to supply the startup and shutdown load requirements of the steam turbine generator auxiliaries and the station common load. The startup transformer is rated 10/12.5 MVA, 161/4.16 kv, OA/FA. The transformer is a three-winding unit with the 161 kv primary windings wye-connected with the neutral solidly grounded, the 4160V secondary windings wye-connected with the neutral low resistance grounded, and the tertiary winding delta-connected.

8.2.3 4160 Volt Auxiliary System Switchgear

The 4160V secondaries of the auxiliary transformers and the startup transformer supply the station 4160V Auxiliary System Switchgear through metal enclosed buses. The buses are of the non-segregated phase type with 5 kv insulation and adequately sized to carry rated current with a hottest spot temperature rise not to exceed 65°C rise above a 40°C ambient.

The station 4160V system consists of five (5) outdoor metal clad switchgear units. The switchgear associated with the steam turbine generator is a double-ended unit with two buses fed by the steam turbine auxiliary transformer and the startup transformer and provided with a tie breaker. Each switchgear associated with the gas turbine generator units is a single bus unit fed by the associated gas turbine auxiliary transformer. The 4160V switchgear supplies power to all motor loads larger than 250 HP and also the station 480V power center and motor control centers through the 4160/480V transformer units.

The switchgear is selected on the basis of maximum available short circuit current and continuous current capacity. Protective equipment provides protection against electrical faults and abnormal system conditions. The switchgear units are provided with stored energy breakers with control power supplies from the station 125V DC system.

8.2.4 480 V Auxiliary System Equipment

The station 480V system is supplied from power centers and motor control centers energized by the 4160/480V transformers. These transformers and their associated switchgear are located indoors. The transformers are dry-type and delta-wye-connected with the neutral solidly grounded. The power centers supply motor loads greater than 100 HP and the motor control centers supply the remaining loads.

Motor circuits are supplied from the power centers by means of stored energy breakers electrically operated from the station 125V DC system and protected by series trip devices with long time and instantaneous elements. Ground fault protection is provided in the transformer neutral and in all the load center feeders with the tripping coordinated.

Motor control centers with molded case circuit breakers and circuit breaker combination starters are provided to feed 480V loads and motors. All motor control center motor starters are self-contained with their own control transformer and circuit breaker.

8.2.5 120 V AC System

The station 120V AC vital buses are supplied from 125V DC/120V AC inverters connected to the station 125V DC system. Standby source is obtained through 480V/120V AC regulated transformers supplied by the station essential motor control centers fed by the emergency diesel driven generator. The 120V AC system is single-phase grounded.

Other miscellaneous AC distribution panels for miscellaneous 120V AC loads are provided throughout the station. These panels are supplied by 480V/208-120V dry-type distribution transformers supplied from the station motor control centers.

8.3 SYSTEM ROUTING AND DESCRIPTION

The physical location and arrangement of the electrical system equipment is such as to minimize vulnerability to physical damage, optimize space requirements and provide accessibility for maintenance, testing and inspection.

8.3.1 Generator Isolated Phase Bus

The isolated phase buses which feed the generator output to the main transformers are located both indoors and outdoors. Generator bus potential transformers, surge protective equipment, neutral bus, and neutral grounding equipment are located indoors. The bus is of the isolated phase type with each aluminum phase conductor supported on porcelain insulators and enclosed by an electrically continuous individual aluminum housing. The enclosure housing is dustproof and weatherproof and suitable for use either indoors or outdoors. Aluminum wall sealing plates are provided where the bus penetrates the building walls and fire walls.

The gas turbine generator main oil circuit breakers and disconnect switches are located outdoors as shown on the Plot Plan, Figure 7.0-1. The three (3) phases of these breakers are mounted on a welded frame and enclosed within three (3) tanks. The breaker has condenser bushings, bushing current transformers, operating mechanism, and a control cabinet.

8.3.2 5 KV Bus

The 4160V switchgear is fed by non-segregated phase bus connected to the low voltage windings of the auxiliary and startup transformers. The buses are capable of carrying rated current continuously without exceeding a conductor temperature rise of 65°C above an ambient of 40°C. All conductors are of high strength aluminum, silver-plated at the joints. Outgoing feed from the switchgear to power center and motor control transformers and motors within the plant is by power cables in underground conduits through duct banks.

8.3.3 Cables And Raceways

The application, installation and routing of power, control and instrumentation cables are such as to minimize their vulnerability to damage from any source and to maintain the integrity of the respective branches.

8.3.3.1 5 KV POWER CABLES

Power cables used in the 4160V system are rated for 5 kv. Power cables are to be stranded copper conductors with insulations that are heat and moisture resistant with flame retardant jackets. These power cables conform to applicable IPCEA standards. Power cables are sized considering load carrying capability, voltage drop, short circuit and overload. Power cables are run in conduits through underground duct banks. These conduits are PVC encased in concrete. Exposed conduit runs are of the rigid metal type.

8.3.3.2 600 VOLT POWER CABLES

Power cables for the 480 volt AC, 110 volt AC and 125 volt DC system are 600 volt insulated and rated for 90°C copper temperature. Cables are stranded copper conductors and have insulations that are heat and moisture resistant with flame retardant jackets. Power cables conform to applicable IPCEA standard cables and are sized considering load carrying capability, voltage drop, short circuit duty and overload duty.

600 volt power cables within the station are to run in cable trays and racks. Where required, trays have covers to exclude dirt and foreign matter. Power cable trays are hot-dipped galvanized ladder type. Care is taken to assure that trays are not loaded beyond manufacturer's recommendations. Galvanized rigid steel or aluminum conduit is used overhead between trays and terminal equipment. Underground ducts of rigid PVC encased in concrete are used for cables outside the plant.

8.3.3.3 CONTROL AND INSTRUMENTATION CABLES

Control and instrumentation cables are to be stranded copper conductors with heat and moisture resistant insulation and flame retardant jackets. The cables are rated 600 volts except for low level analog and computer circuits which are rated 300 volts. Control cables are of multi-conductor type and are to be No. 14 AWG or larger, stranded and rated for 90°C conductor temperature. Low level instrumentation cables are provided with shielding to reduce "noise" pickup. All cables conform to applicable IPCEA standards.

Control and instrumentation cables within the station building are to run in cable trays. Separate cable trays are utilized for control and instrumentation, isolated from each other and from power cable trays. Control and instrument cable trays are hot-dipped galvanized steel with solid bottoms and close fitting covers. Cable trays, when stacked one above the other, have the power cable tray on top with control and instrumentation cable trays below. In general, conduits in underground duct banks (PVC encased in concrete) are used for cables outside the station building. Exposed conduits, where required, are of the rigid metal type.

SECTION 9
MAINTAINABILITY

An evaluation of the maintainability of the plant must consider the physical location of components within the plant systems, the functional interdependency of these systems on plant operation and the effect of a failure of a component upon the operation of the plant.

9.1 COMPONENT LOCATION

The physical location of a component in a system influences its maintenance cycle by virtue of its accessability with respect to other components. The designs will be monitored in order to assure that components with inherently low mean-times-between-failures are made as accessible as possible.

9.2 FUNCTIONAL INTERDEPENDENCY

The functional interdependency of the systems is defined in the Failure Mode, Effects and Criticality Analyses (FMECA) prepared as part of the Reliability Assessment Program. The determination of the functional interdependency of the plant systems identifies the criticality of the components within these systems, in that particular attention must be given to their accessability for maintenance.

9.3 FAILURE EFFECT

The effect of the failure of a component in the plant systems can be expressed as an equivalent loss in plant generating capacity. For example, a loss of a plant safety system results in a shutdown of a portion of the system reducing plant output. Similarly, a reduction in plant efficiency, resulting from a component failure can be expressed as an equivalent capacity penalty.

9.4 MAINTAINABILITY ASSESSMENT

The maintainability of a plant can be evaluated in terms of component location, functional interdependency, failure effects and mean time between failure data. The following approach will be taken to assess the maintainability of the plant.

Each major component will be assigned a maintenance code number containing the following information:

1. A Major Subsystem identification number which locates the component in its functional subsystem. Typical functional subsystems are:

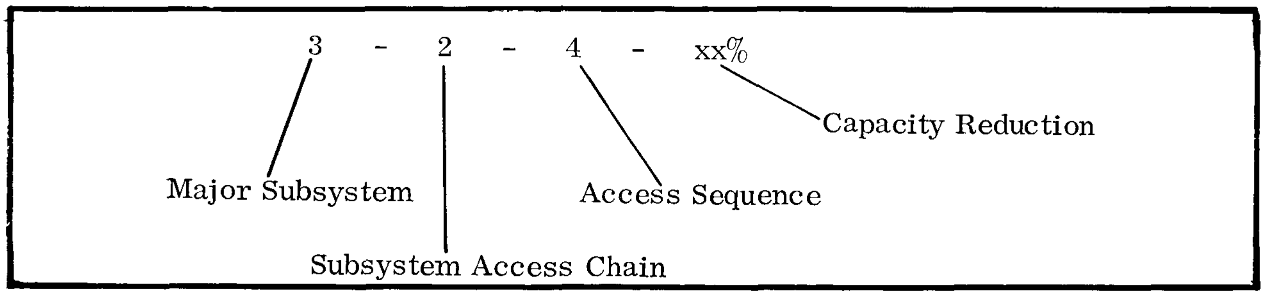
   - Gas Turbine Engine
   - Steam Supply System
   - Fuel Supply System.

2. A Subsystem Access number which places the component in its assigned disassembly chain in the subsystem.

3. An Access Sequence number which provides a physical location of the component in its disassembly chain. An access sequence number of 2 indicates that it is necessary to remove two other components in order to service the component.

4. A Plant Capacity Reduction number which shows the equivalent reduction, in percent, of plant generating capacity due to a failure of the component.

The following is an example of a maintenance code number.



9.5 MAINTAINABILITY EVALUATION MATRIX

In the construction of the matrix, the ordinate consists of a list of all of the major subsystems, with their components arranged in a sequence which is determined by their Access Sequence. Each grouping in a subsystem is called a Subsystem Access Chain. Each major subsystem may contain several Subsystem Access chains in order to identify the removal procedure for all components in the subsystem.

The matrix abscissa consists of the mean time between failure, for each component, shown as a function of plant operating time.

The format for the Maintainability Evaluation Matrix is shown on Figure 9.5-1. The sample matrix indicates that the maintenance cycle for major subsystem No. 5 (Turbine or Boiler or Generator or etc.) will probably be every 800 hours and will be fixed by the performance of component E. Once this information is available, the following actions should be initiated in order to improve the maintainability of the plant:

- Attempt to extend the life of Component E.
- Improve the accessability of Component E.
- Provide component redundancy or an alternate operating mode which would allow continued operation of the system with an acceptable performance penalty.

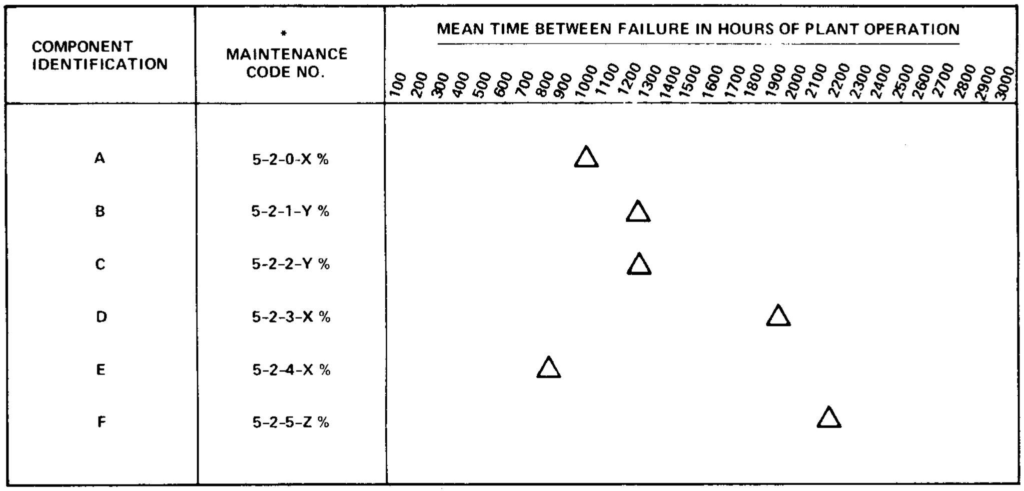
9.6 SUMMARY - MAINTAINABILITY

The maintainability of the plant will be evaluated during the design period by means of a Maintainability Evaluation Matrix. The matrix will identify:

- The maintenance cycle, based on MTBF estimates, for all major components.
- The scope of the maintenance work in terms of component accessability.
- The penalty, in terms of plant reduction in generating capacity, incurred during the maintenance period.

The sources of information for the matrix are:

- Mean-time-between-failure estimates from the Reliability Assessment Task.
- The functional interdependency of the plant systems, as defined in the FMECA's.
- The accessability of components determined from the Maintenance Instructions.



* MAINTENANCE CODE NUMBER STRUCTURE

(MAJOR SUBSYSTEM) - (SUBSYSTEM ACCESS CHAIN) - (ACCESS SEQUENCE) - (CAPACITY REDUCTION)

MAINTAINABILITY EVALUATION MATRIX
Figure 9.5-1

SECTION 10
RELIABILITY, MAINTAINABILITY AND AVAILABILITY

10.1 OBJECTIVE

Dependable operation of the plant in consonance with the design objectives cited for the reference design is the principle objective of designing for reliability. It encompasses an integration of the necessary technologies to attain a system which maximizes the return on the investment as well as meeting the necessary safety and environmental requirements.

To achieve the best return on investment the design for reliability must include the broader system goals of availability and plant capacity factor, so that the design approach is more logically described as a design for Reliability, Maintainability and Availability, or simply "design for RMA".

As discussed by many others, the incorporation of space systems technology into industrial/commercial applications has led to broader understanding and utilization of the technology. Applying this broader understanding has resulted in the use of the plant capacity factor term as a bridge between one shot or "how long" missions and those with the additional dimension of "how much".

Design for RMA must therefore have as its objective the optimization of a design from the viewpoint of reliability, maintainability and availability tempered by an objective to maximize the plant capacity factor.

10.2 APPROACH

To assure that the above noted objectives are achieved, the technologies available from aerospace and other reliability/safety sensitive applications have been used as part of the design process in order to impact concept selection.

Failure Mode Effects and Criticality Analyses (FMECA) are being performed at the system level to identify single failure points — those related to safety and/or complete shutdown — and to assess the impact of other failures on plant availability and capacity factor.

Fault tree analysis was performed to establish failure mode causes for selected failure modes. This was done to augment the FMECA in areas where more detailed definition of subtier components was available and to develop a manageable use of the technique for Phase II. Results are discussed in Subsection 10.3.2.

RMA modelling has been initiated to the extent possible during Phase I. This has been done to assess the reference design, the impact of failure mode effect removal, and to initiate effort in establishing availability criteria for the major units of the reference design.

10.3 FAILURE MODE EFFECTS AND CRITICALITY ANALYSES (FMECA)

Utilizing the heat balance diagrams developed for the system described in Section 1 of this report, a FMECA has been completed at the system level, implemented by well documented procedures. The FMECA detail work sheets and results are found in Table 10.3-1. The corresponding System Block Diagrams are shown on Figures 10.3-1 through 10.3-7.

In order to assess the importance of each failure effect, criticality factors were developed. The categories were derived on the basis of safety and effect on power output. Table 10.3-2 lists the chosen criticality categories.

Items in category A or S are generally considered single failure points for purposes of this study. Single failure points require well considered risk evaluations, usually mandating design alternatives and contingency plans for either eliminating the effect or reducing risk to an acceptable level. During Phase I of this program no attempt to study failure probabilities in detail has been made. As definition of components develops in ensuing phases, these data will permit tradeoffs in those areas identified as sensitive to component failure rate.

10.3.1 FMECA Results

The following single failure points have been identified as requiring special attention, particularly as the design hardens during Phase II.

A. Steam Turbine Condenser Inoperative

If the condenser is inoperative the plant will shutdown.

B. Control Development Criteria

Control development criteria will include requirements to eliminate common mode failures which might arise from selection of power source, its backup and physical placement of components, cabling, etc.

TABLE 10.3-1

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS • • • WORK SHEET

COMPONENT/SUBSYSTEM COAL GASIFICATION - TREATER
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
SHEET 1 OF 23
DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Treater Clogs 10-1-1	OPERATE	Coal flow to gasifier reduced/stopped Train output power reduced/stopped	Switch to back-up fuel for turbine Provide clean-out capability	Gas Flow, Pressure Hopper Coal Depth	D
Treater Hx Rupture 10-1-2	OPERATE	Loss of HP steam for turbine. Possible bleed down of other trains with corresponding power loss.	Isolate rupture. Shut down treater and repair. Operate G turbine on back-up fuel.		SFP
Treater Leakage 10-1-3	OPERATE	(Leakage to outside is a possible fire hazard). Cool transport capability reduced with possible clogging.	See 10-1-1. Also develop contingency plan for fire hazard leakage.	Pressure Δ Visual	
Booster Compressor Output Loss 10-1-4	OPERATE	Fluidizing and gasification retarded or stopped. Turbine power output reduced or stopped.	Shut down, repair affected train. Adjust power output per preplanned schedule. If no alternate fuel back. Otherwise use back-up fuel to maintain power during repair of compressor.	Low Gasifier Pressure	

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS • • • WORK SHEET

COMPONENT/SUBSYSTEM COAL GASIFICATION - GASIFIER
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
SHEET 2 OF 23
DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Gasifier Separator Output Dirty 10-2-1	OPERATE	Contaminates, corrodes, abraides downstream equipment with possible turbine damage.	Automatic shutdown via gas contaminant alarm. Repair and clean separators.	Sensor	D
Gasifier Separator Clogs 10-2-2	OPERATE	Possible output gas contamination with effects similar to 10-2-1 above.	Same as 10-2-1 above.	Sensor	D
Gasifier Lock Hopper Leakage 10-2-3	OPERATE	Loss of fluid, pressure, leading to reduced out of steam and turbine and gas turbine. Possible external physical damage if problem persists.	Isolate faulted gasifier. Switch to back-up to operate turbine power train. Steam turbine power output schedule is reduced.	Gasifier Pressure Sensor	D

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM COAL GASIFICATION - GAS CLEANUP
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
SHEET 3 OF 23
DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
Scrubber Output Dirty 10-3-1	OPERATE	Contamination and/or erosion of downstream systems. Possible fouling of the sulphur removal system. Possible fouling of the turbine combustor and other parts - resulting in reduced G.T. output or shutdown of train.	Shut down train. Switch to back-up fuel to operate gas turbine. Reschedule system output power at lower level. Assure monitor capability provides clean-up access. Provide filters.	Scrubber Fluid Flow Gas Sampling	E
Sulfinol Process Inoperative 10-3-2	OPERATE	Sulfide or other contaminated gas passes through to the GT with possible erosion/corrosion damage to valves, turbine parts. Effects on machinery useful life could be significant.	Shut down train based on contingency plan - i.e., subject to schedule and other considerations. Repair sulfinol system, while operating with back-up fuel. Clean lines. Inspect and clean GT according to contingency plan.	Gas Sensors	E

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM GAS TURBINE - FUEL SYSTEMS
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
SHEET 4 OF 23
DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
Fuel Heater Tube Leakage 20-1-1	OPERATE	Possible water injection into combustor with unknown damage through to turbine blades.	Isolate fuel heater. Shut down train and repair heater. Operation of gas turbine on back-up fuel may be possible subject to damage in heater.	Fuel lit	D
Fuel Heater Clogged 20-1-2	OPERATE	Reduced gas flow. GT power output limited. Flow impedance reflected back causing shutdown.	With CG train shut down to a "Hot Standby" operate GT on back-up fuel.	Gas flow	
Combustor Gas Input Reduced 20-1-3	OPERATE	Reduction of train output power. Reduced air flow to gasifier resulting in reduced gas output with turbine output settling at the gas flow condition.	Isolate gasification system. Switch to alternate fuel for repair duration. Reschedule system output power. Identify gas filtering requirements and consider back-up filter capabilities.	PWR gas flow	
Combustor Failure 20-1-4	OPERATE	Loss of turbine output and consequent reduction in system power.	Shut down train and repair as required. Reschedule system output power accordingly.	PWR RPM	D

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM GAS TURBINE - MACHINERY
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
GT Machinery Failure 20-2-1	OPERATE	Single generator output power is lost. Compressed air flow to booster compressor and gasifiers is reduced. Total heat to HRSG is reduced affecting steam turbine output. Reduction in gasifier output also affects HP steam generation.	Shut down train to a hot standby. Isolate GT for repair. Reschedule plant output power.	RPM PWR	D
Loss of Cooling Air 20-2-2	OPERATE	Turbine blade cooling loss. Possible turbine damage or useful life reduction.	Immediate turbine shutdown and transfer CG train to hot standby. Isolate and repair. Reschedule plant output power.	T, P	D, S
G.T. Generator Fault 20-3-1	OPERATE	Loss of 20 percent power from plant immediately. Further losses to 25 percent possible depending on cutback requirements for the train.	Isolate generator via disconnect. Cut back turbine to hot standby or shut down as required. Initiate repairs. Reschedule plant output power.	Power	D

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM TURBINE - MACHINERY
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
SHEET 6 OF 23
DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Steam Turbine Machinery Failure 30-1-1	OPERATE	a) Proportionate loss of S.T. generated power. b) Possible loss reflection back to G.T.'s because of excess waste heat.	a) Shutdown. Isolate turbine and repair. b) Consider steam bypass to condenser while maintaining G.T. outputs.	Power RPM	D

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM TURBINE - FLUID SYSTEM
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
HP Turbine Steam Output Pressure Low 30-2-1	OPERATE	Reduction of gasifier input steam pressure hence gasifier and GT output. Possible like effect to all trains, leading to complete plant shutdown. HT transfer effects in reheater due to gas velocity increase.	If pressure loss requires it, shut down. Isolate failure and repair. Consider providing means to use some bypass steam to maintain gasification systems operational, and to obtain GT power output for each train even though the steam turbine is down.	RPM, POWER Pressure	D-A SFP
LP Turbine Steam to Claus Unit Low 30-2-2	OPERATE	Reduced efficiency in the claus unit. Possible gss contamination to the point of train shutdown. If low output is due to leakage, all trains may be affected.	Isolate cause. If single train oriented, switch to back-up fuel and operate. If a common mechanism, shut down and repair. Consider means to either make the GT trains completely independent of the ST for process steam, water or provide diverse backup.	Dirty Gas Alarm	D-A SFP
LP Turbine Steam Output tp FW Heater Low 30-2-3	OPERATE	Reduction in FW temperatuer with some loss in efficiency.	Identify cause of problem and schedule maintenance accordingly.	FW Temp.	F
LP Turbine Steam Output to Deaerator Low 30-2-4	OPERATE	Effects as in 30-2-3 above.	Same as 30-2-3 above. Consider control means to steam turbine interceptor and stop valves in order to maintain pressure to C.G.'s.	FW Temp.	F

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM TURBINE - GENERATOR
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
ST Turbine Electric Generator Loss of Output 30-3-1	OPERATE	Electrical output power reduced a minimum	Disconnect generator output. Idle ST and bypass steam to condenser. Operate plant at a reduced power output schedule as repairs to generator are made. Evaluate optimum bypass capability.	PWR	D

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM SWITCHGEAR - MAIN BUS
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 12-1-76
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FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
GT Output Bus XFMR Fault 40-1-1	OPERATE	Loss of 20 percent power to auxiliary bus. Loss of auxiliaries for the affected train. Train shutdown may be required leading to 25 percent loss of power.	Isolate faulted transformer for repair/replacement Tie auxiliaries to available generator.	BKR Trip, PWR Output	E
GT Auxiliary XFMR Fault 40-1-2	OPERATE	Loss of power to train auxiliaries causing train shutdown and reduction of plant output by 25 percent.	Isolate faulted transformer for repair/replacement. Tie auxiliaries to available generator.	BKR Trip, PWR Output	D
Main XFMR Failure 40-1-3	OPERATE	Possible output power reduction to level of second transformer capabilities; i.e., down to 75 percent of system output rating.	Disconnect and isolate transformer. Arrange bus connections for single XFMR. Schedule power out accordingly. Repair/replace transformer. Verify adequacy of components – breakers, disconnects, remaining transformer – to handle higher power conditions during maintenance operations.	BKR Trip, PWR Output	C

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM SWITCHGEAR - PROCESS POWER
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Loss of GT Auxiliary Power 40-2-1	OPERATE	Booster air compressor, gasification power – i.e., loss of auxiliary power to the train in question. This results in train shutdown.	Isolate and repair.	Multiple Alarms and Shutdowns	D
Loss of ST Auxiliary Power 40-2-2	OPERATE	Loss of BOP process functions.	A redundant auxiliary bus transformer is provided and auxiliary power buses are cross coupled.		

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM SWITCHGEAR - AUXILIARY BUSES
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Bus A Faulted 40-3-1	OPERATE	Possible loss of 50 percent power due to loss of train output. System shutdown.	Isolate fault. Switch outputs to Bus B. Repair as required. Verify bus and breaker disconnect capacity for continuous duty under these conditions.	Fault Detector Breaker Status	C
Bus B Faulted 40-3-2	OPERATE	Effects similar to 40-3-1 above.	See 40-3-1 above substituting B for A.	Same as 40-3-1 Above.	C

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM GENERATION HRSG
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 12-1-76
DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
HRSG Super Heater Leaks 50-1-1	OPERATE	a) HP steam eented to HRSG internals. Output to ST reduced HRSG overall equilibrium jeopardized.	Isolate HRSG. Repair HRSG while operating the plant on a reduced power schedule, with the affected train down.	Pressure; ST Power Output	D
		b) Possible drawing down of other high pressure inputs to ST with significant reduction in ST output.	Isolate HRSG. Repair HRSG while operating the plant on a reduced power schedule, with the affected train down. Evaluate methods to assure functional independence at ST interfaces.	Pressure; ST Power Output	
HRSG Reheater Leaks 50-1-3	OPERATE	Effects similar to 20-3-1 above.	Same as 20-3-1 above.	Pressure; ST Power Output	D
HRSG Economiz Economizer Leaks 50-1-4	OPERATE	Effects similar to 20-3-1	See 20-3-1 above.	Pressure; ST Power Output	D
HRSG Fuel Heater Fluid Loss 50-1-5	OPERATE	Inability to preheat fuel. Possible gas combustion produces cleanliness problems.	Isolate and repair. To avoid train shutdown consider value of back-up heating.	Fuel Gas Temperature	F

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM GENERATOR - GASIFIER STEAM DRUM
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
HP Drum at Gasifier Leaks 50-2-1	OPERATE	Loss of HP steam for turbine. See 10-1-2	Isolate leak. Shut down affected portions of train and repair. Operate G turbine on back-up fuel and at reduced power.	Pressure Flow	E

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM GENERATION - DEAERATOR
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
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FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
Deaerator LP Evaporation Leak 50-3-1	OPERATE	Loss of fluid into HRSG. Interaction with turbine exhaust causing temp CTL problems and shutdown.	Shut down train and repair. Reschedule plant power output. Verify that design shows independence from other trains on the steam side.	Pressure, Flow	E
Deaerator Leaks 50-3-2	OPERATE	Loss of feedwater with effects similar to 50-3-1. Reduced hot water flow to claus unit with resultant reduced performance.	Shut down train if required and repair. Otherwise operate with make-up until scheduled maintenance period.	Pressure, Flow	E, F
Boiler Feed Pump Loss of Output 50-3-3	OPERATE	Flow to HP S. drum and C. Gas Cooler is lost with corresponding reduction of input to the steam turbine. This reduction reflects into the coal gas generation system leading to cutback.	Shut down train and repair/replace. Consider redundancy.	Pressure, Flow	D

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM GENERATOR - GAS COOLER
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
Gas Cooler Ruptures 50-4-1	OPERATE	Loss of HP steam for turbine. Gas, Steam, Water interactions at high temperature in GT. Possible high back pressure transient to the gasifier.	Shut down train. Isolate gas cooler. Operate G turbine with back-up fuel. Rnu system at reduced power output schedule during repair cycle. Evaluate over pressure protection for the gasifier side of the gas cooler.	P, Flow Gas Cooler, T	C, S

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM STEAM GENERATION - CONDENSER
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Condenser Condensate Pump Output Loss 50-5-1	OPERATE	Unable to move condensate. Possible excess water in condenser. Shutdown level is exceeded. Since steam condensing function is not possible, a complete plant shutdown is necessary.	Shut down and repair pump. Redundant pump configuration (3/2) is to be used. Loss of all is a very low probability.	Pump Flow	F
Condenser Circulating Water Pump Output Loss 50-5-2	OPERATE	Steam turbine state point changes. Reduced power output with possible shutdown of complete plant.	Repair while running at reduced power. Two 50-percent pumps are used.	Flow	SFP
Condenser Inoperative 50-5-3	OPERATE	Unable to operate S.T. or bypass steam causing plant shutdown.	Eliminate single failure points in fluid systems. Provide redundant cooling passages where feasible. This SFP appears unfeasible with current technology. Phase II should show a thorough evaluation of potential failure mechanisms in this area.	Flow, Temp. Power	A SFP

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM BALANCE OF PLANT - PROCESS WATER
REFERENCE SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY G.L. WAGNER
REVISION
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DATE 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Loss of Cooling Water 60-1-1	OPERATE	Lube oil cooling lost. Generator hydrogen cooling degraded/inoperative. Steam system condenser performance degraded (see 50-5-2).	Provide the necessary redundancy/margin to preclude single failure points, through back-ups and loop sharing under fault conditions.	Flow, P Indications Lube Temp. Brg. Temp.	D D D

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM: BALANCE OF PLANT - PROCESS AIR
REFERENCE: SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY: G.L. WAGNER
REVISION:
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DATE: 12-1-76
DATE: 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Loss of Instrument Air 60-3-1	OPERATE	Loss of pressure sensors for control causing trips and plant shutdown.	Instrument air is cross-coupled to plant service air and GT compressors for backup. The compressor for instrument air is maintainable while the system operates from one of the GT compressor outputs from plant service air.	Panel run light, Air pressure	B
Loss of Service Air 60-3-2	OPERATE	Loss of (1) instrument air back-up. Loss of air operated support functions.	Isolate and repair system backed up as described in 60-3-1 above.	Panel run light, Air pressure	F

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM: BALANCE OF PLANT - AUXILIARY POWER
REFERENCE: SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY: G.L. WAGNER
REVISION:
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DATE: 12-1-76
DATE: 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Loss of Auxiliary Power 60-5-1	OPERATE	Loss of coal preparation and grinding, auxiliary water booster pump, circulating water and gas clean-up for either half of the plant.	Isolate and clear fault. If failure is XFMR or breaker then cross couple and resume full power operation. If other, repair while operating at reduced plant power. Review detailed design for common mode faults to assure use of back-up if required.	Annunciator trip	B

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM: BALANCE OF PLANT - FUEL OIL
REFERENCE: SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY: G.L. WAGNER
REVISION:
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DATE: 12-1-76
DATE: 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
Loss of Liquid Fuel Delivery to Combustor 60-6-1	OPERATE/ START-UP	Unable to achieve a standby mode which would permit start or restart. Unable to provide back-up for gasifier.	Locate fault and repair. Consider access and repair capability under normal operation.	C/O for Start Sequence	D

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM: BALANCE OF PLANT - COAL HANDLING
REFERENCE: SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY: G.L. WAGNER
REVISION:
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DATE: 12-1-76
DATE: 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION: WITHOUT COMPENSATION	EFFECTS ON SYSTEM OPERATION: CORRECTIVE ACTION	DETECTION METHOD	CRIT. CATEGORY
Lock Hopper Leakage 60-7-1	OPERATE	Reduced treater pressure. Ultimate reduced gasifier pressure, flow, reduced gasification and power output from affected gas turbine.	Redudnant lock hoppers should prevent shutdown. Schedule repair for next maintenance/inspection interval.	Same pressure at hopper.	E
Lock Hopper Clogs 60-7-2	OPERATE	Coal transport to treater reduced, stopped. Gas output, hence power for affected train reduced, stopped.	a) Same as 60-7-1 above. b) Transport passages to be smooth with large radius turns. c) Coal input conditions to be monitored, controlled to enhance fluidizing.	Coal back-up gas flow, temp. changes	E

TABLE 10.3-1 (Continued)

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM: BALANCE OF PLANT - CHEMICAL FEED
REFERENCE: SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY: G.L. WAGNER
REVISION:
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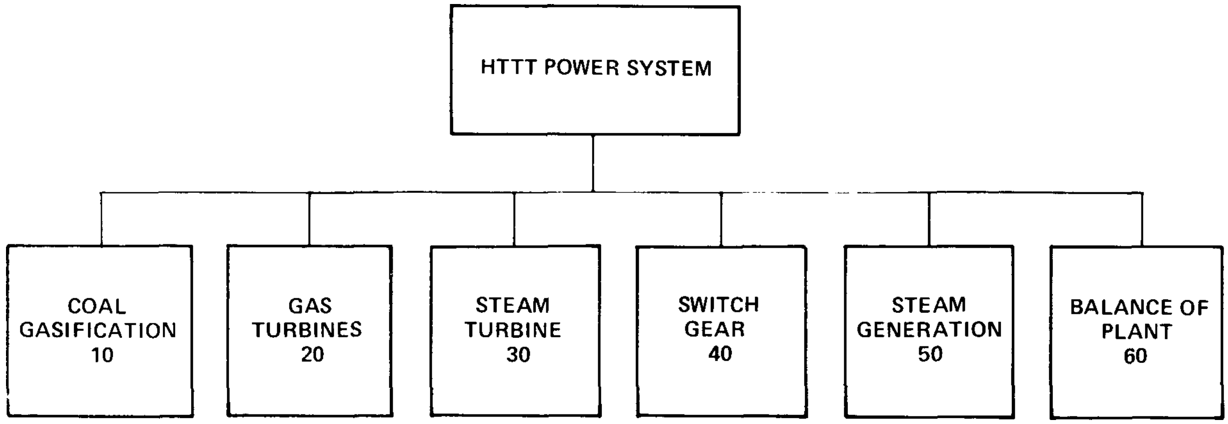
FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Amine Input Inoperative 60-8-1	OPERATE	Possible increase of corrosion in heat exchangers, other piping.	Redundant injection pumps to be provided in critical areas. Other repair/replacement is anticipated as short cycle, on line.	Panel run light fluid chemistry	F
Hydrazine Input Inoperative 60-8-2	OPERATE	Possible corrosion in steam and condensate lines, reducing useful life in these areas.	Same as 60-8-1 above.	Same as 60-8-1	F
Phosphate Input Inoperative 60-8-3	OPERATE	Reduced P.H. in steam drums increasing the difficulty of undesirable salts removal.	Same as 60-8-1 above.	Same as 60-8-1	F

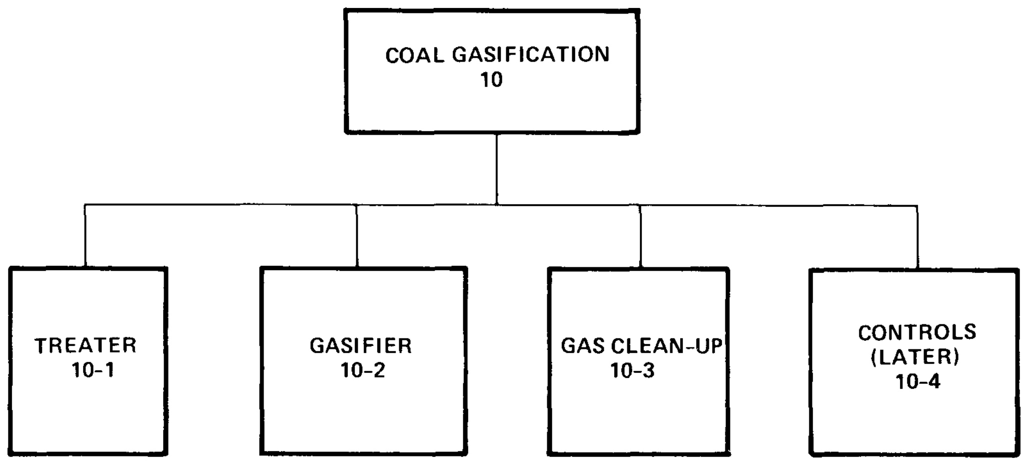
SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM: BALANCE OF PLANT - LUBE OIL
REFERENCE: SYSTEM FLOW DIAGRAM SCHEME IV
PREPARED BY: G.L. WAGNER
REVISION:
SHEET 23 OF 23
DATE: 12-1-76
DATE: 9-2-76

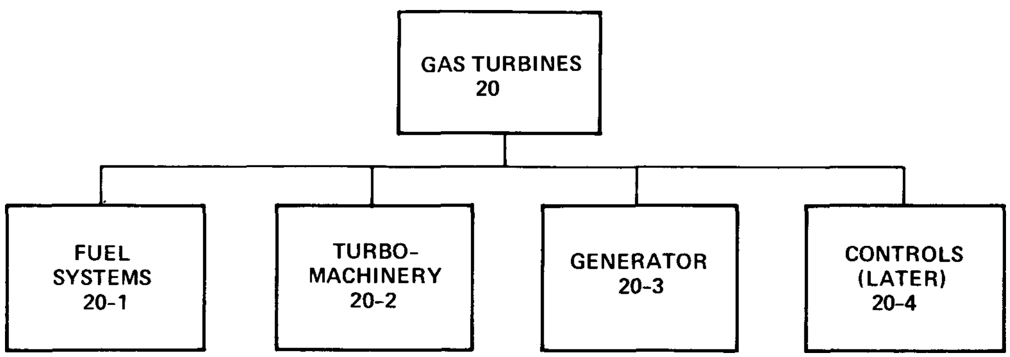
FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT. CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		
Loss of GT Lube Oil 60-9-1	OPERATE	Possible severe damage to GT bearings, shaft, generator bearings, shaft.	A redundant lube feed system is used which contains both AC and DC operated back-ups. This assures non-damaging shutdown. Provide periodic inspection and test of redundant components.	Auto trip electrically	D
Loss of S.T. Lube Oil 60-9-2	OPERATE	Possible severe damage to S.T. bearings, shaft and/or generator bearings, shaft.	Design of this lube system logically identical to that described in 60-9-1 above.	Same as 60-9-1 above	D



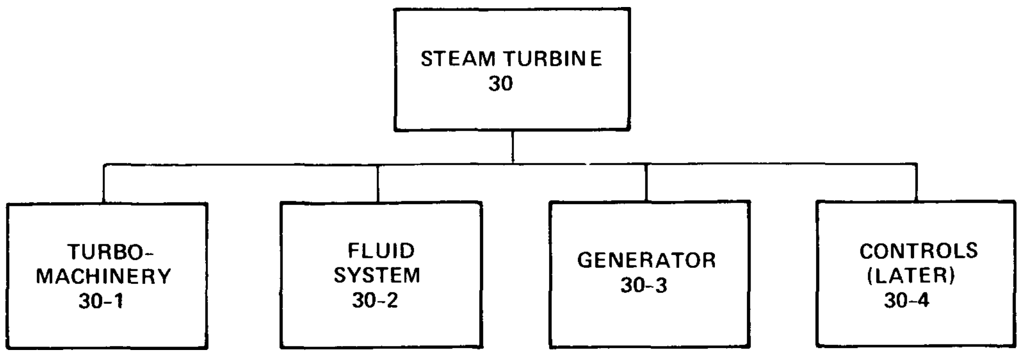
HTTT POWER SYSTEM FAILURE MODE CODE
Figure 10.3-1



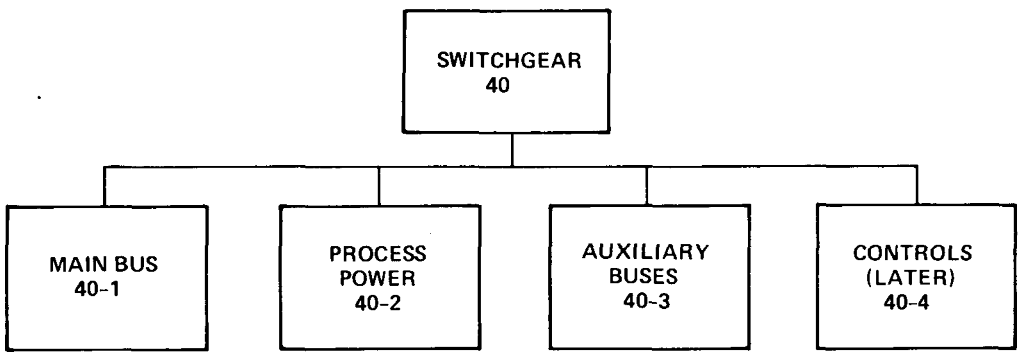
COAL GASIFICATION SYSTEM FAILURE MODE CODE
Figure 10.3-2



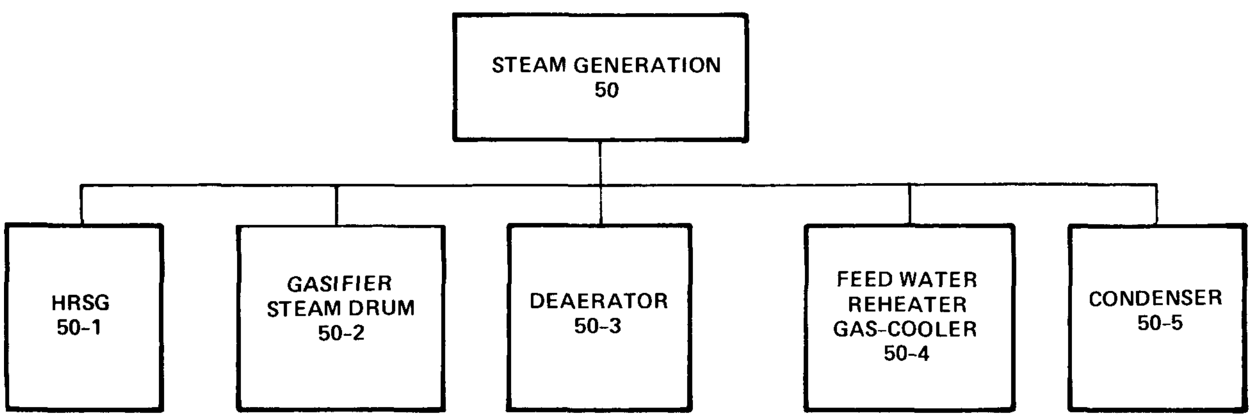
GAS TURBINE FAILURE MODE CODE
Figure 10.3-3



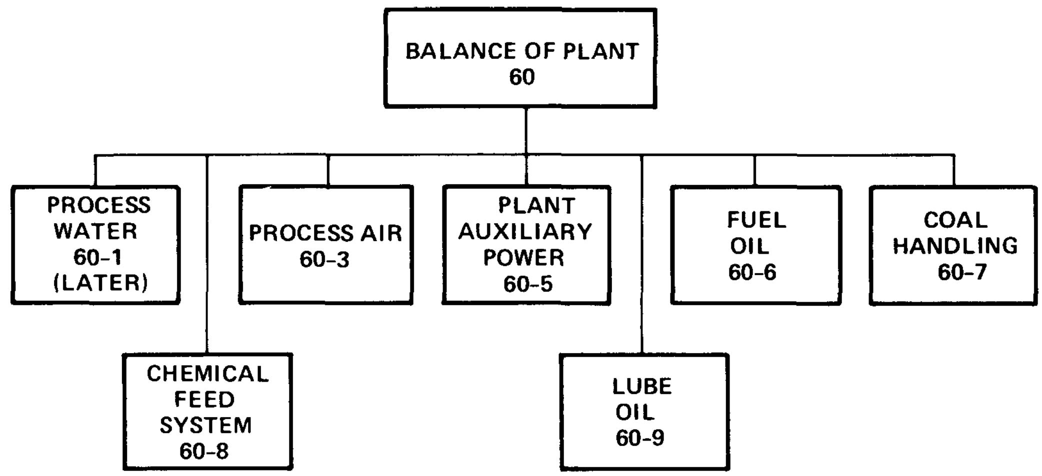
STEAM TURBINE FAILURE MODE CODE
Figure 10.3-4



SWITCHGEAR FAILURE MODE CODE
Figure 10.3-5



STEAM GENERATION FAILURE MODE CODE
Figure 10.3-6



BALANCE OF PLANT FAILURE MODE CODE
Figure 10.3-7

TABLE 10.3-2
CRITICALITY CATEGORIES FOR FMECA

Category	Criticality Factors
A	100 % Loss of Power Output
B	75 - 100% Loss of Power Output
C	50 - 75% Loss of Power Output
D	25 - 50% Loss of Power Output
E	10 - 25% Loss of Power Output
F	0 - 10% Loss of Power Output
S	Possible personnel safety effect

It should also consider optimization and standardization of shutdown limits and shutdown/alarm selections, since the cyclic behavior of a system has significant effect on its useful life.

C. Balance of Plant (BOP) Failures

Failures which might occur in balance of plant equipment/processes can be just as important to attaining high availability as the running gear. Therefore, in Phase II as the BOP is more completely defined, all potential single failure points such as in the condenser cooling water loop (see A above) will be evaluated, taking into account not only their effect but the likelihood of occurrence as well.

Failure modes which affect single trains or which otherwise result in partial power output conditions are listed in the FMECA worksheets in Tables 10.3-1. These and the single failure point areas discussed above will be reviewed early in Phase II to establish whether to

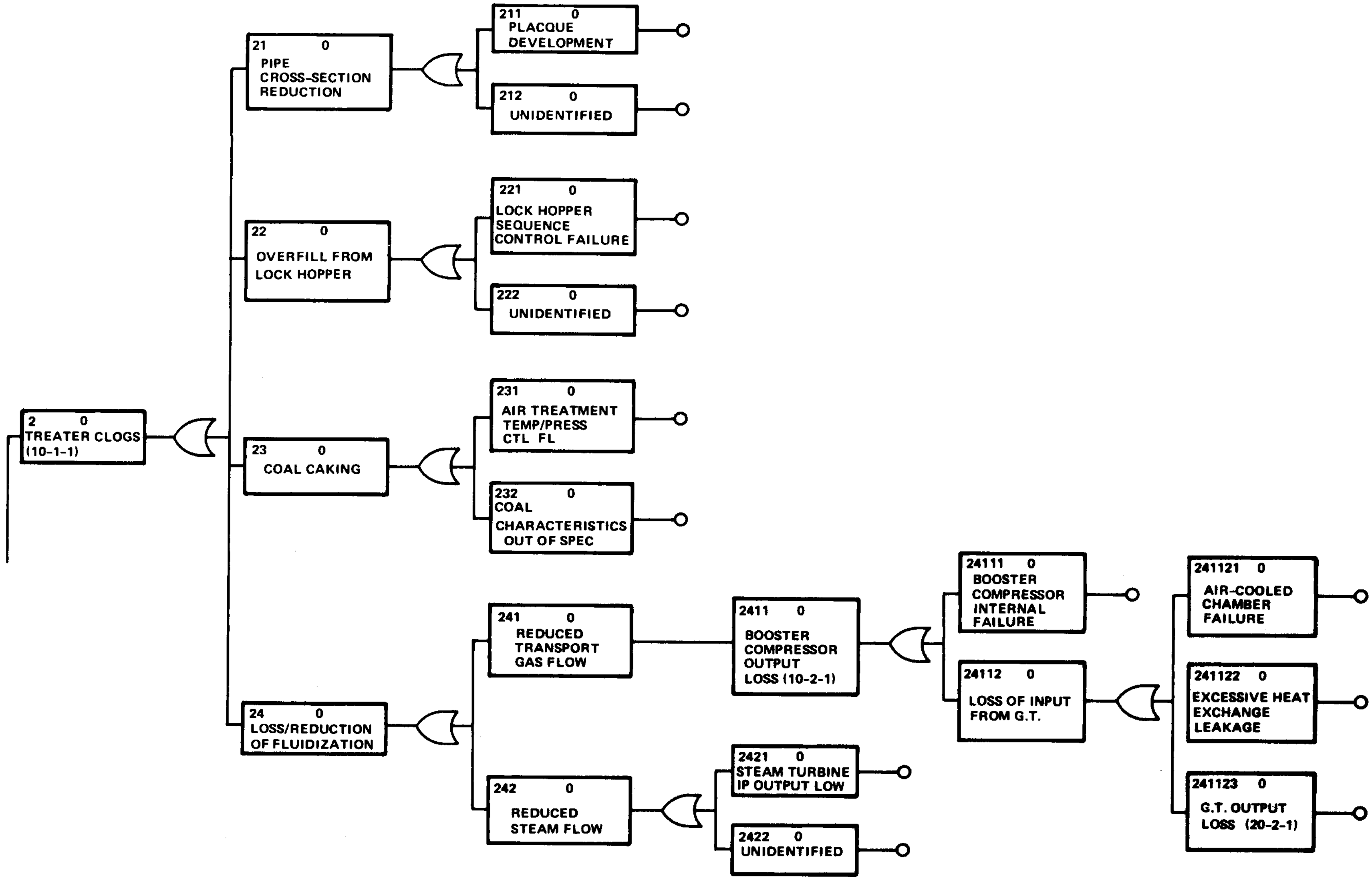
a) Alter the reference design to incorporate modifications which eliminate the failure mode or its effect.

b) Make no change.

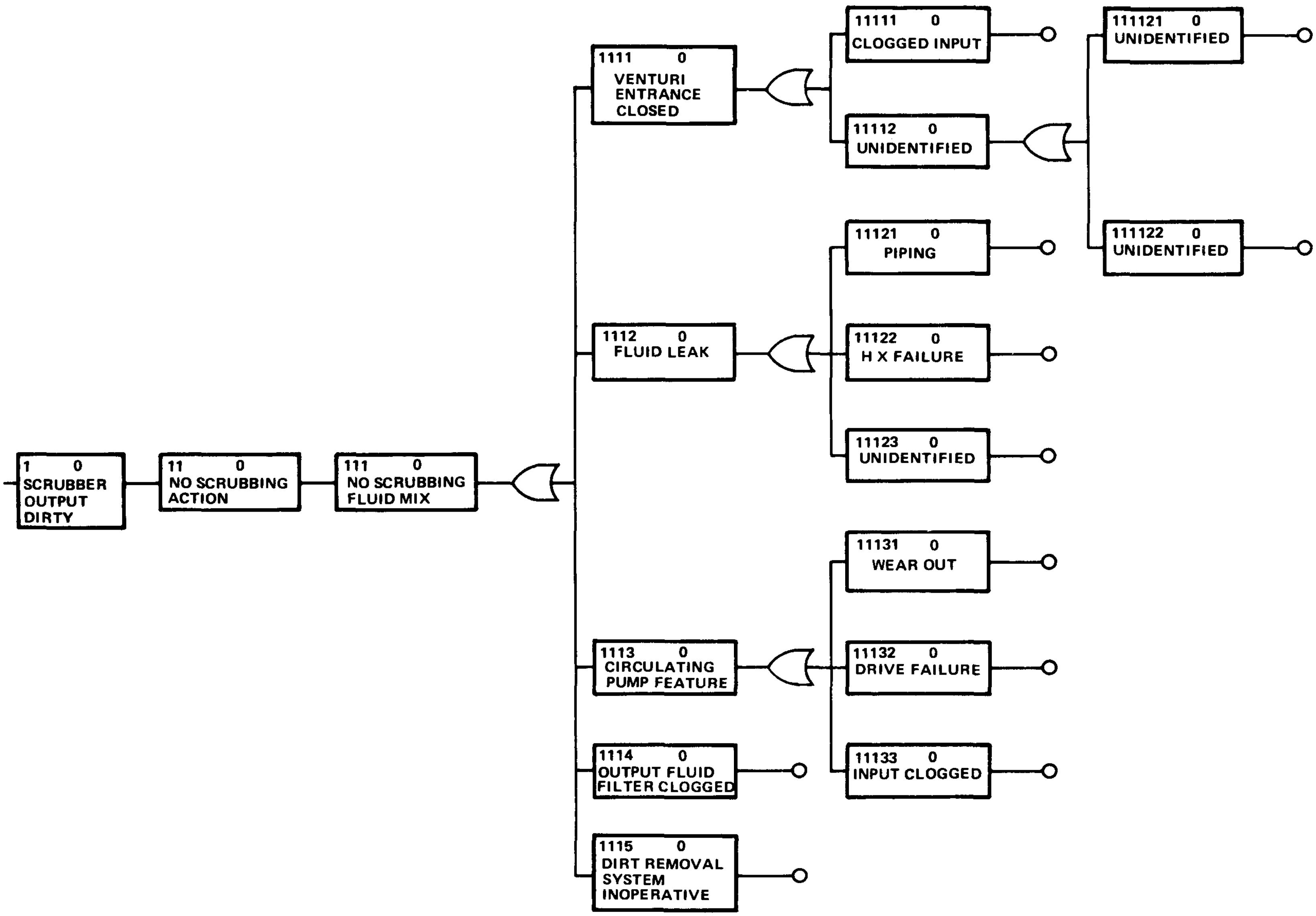
c) Identify more definitive analysis further in Phase II.

10.3.2 Fault Tree Analysis (FTA)

Fault Tree Analysis has been performed, using certain system failure modes as undesired events and proceeding downward to levels of detail consistent with the present study. This hybrid approach of using FTA to continue deductive analysis of important failure modes and their causes should prove quite beneficial in Phase II. Some examples of this use are shown in Figures 10.3-8 through 10.3-10. While not complete, the trees generated have demonstrated the techniques' usefulness in defining mechanisms of failure and underlining design criteria for lower-tiered components. For example, in Figure 10.3-8, the treater could become clogged ultimately, due to a lock hopper sequence control failure. Hence, a requirement develops to not only assure that coal. gets into the treater-the lock hoppers are redundant for that purpose - but also that sequence failures which permit overfilling are precluded. Finally, as fault trees are developed during Phase II, they will be used to augment the RMA modelling which is discussed in the following section.

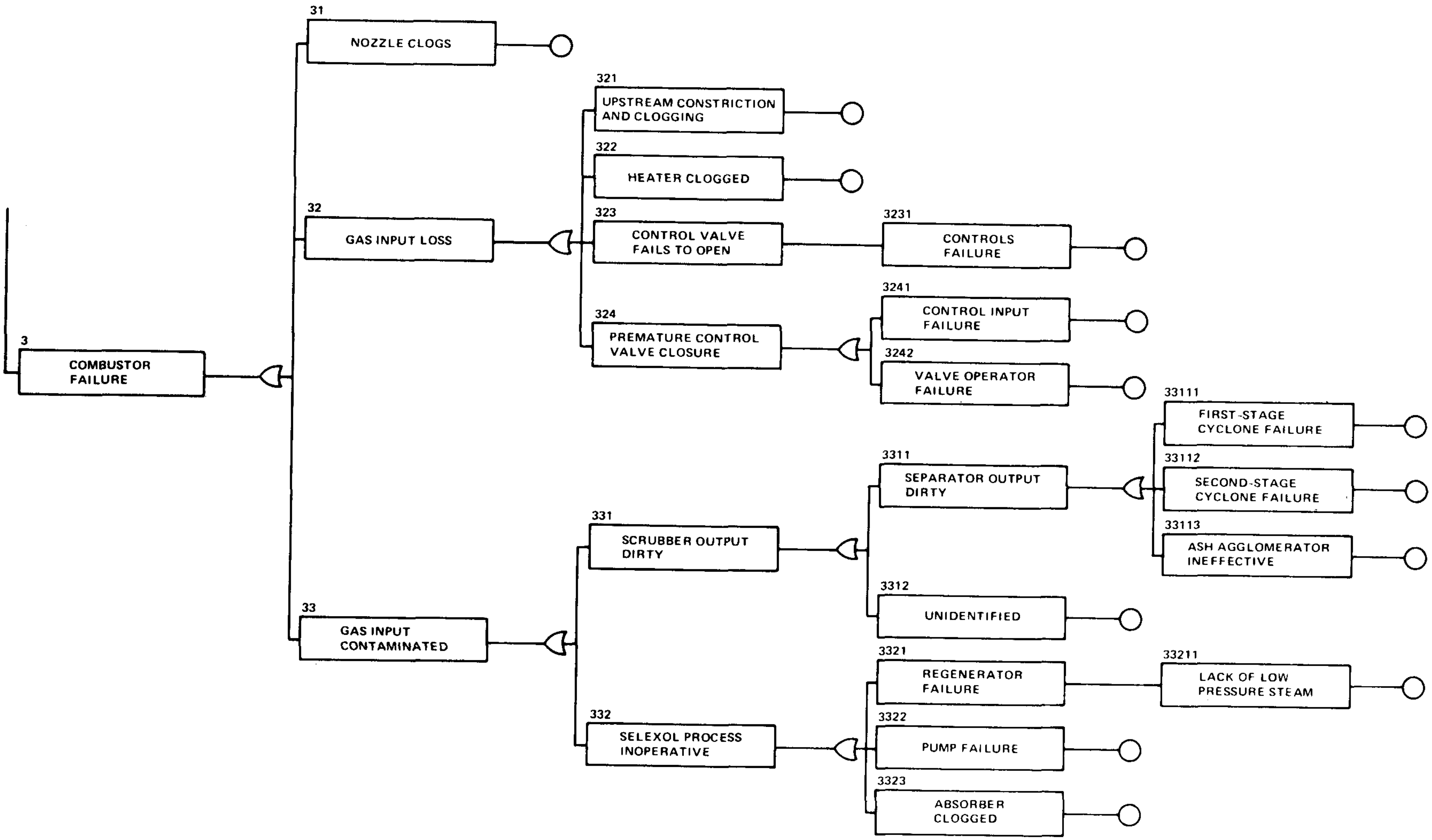


FAULT TREE SEGMENT FOR EMECA (10-1-4) USING WESTINGHOUSE SIMPLOT
Figure 10.3-8



FAULT TREE SEGEMENT FOR FMECA (10-3-1) USING WESTINGHOUSE SIMPLOT

Figure 10.3-9



FAULT TREE SEGEMENT FOR FMECA (20-1-4) USING WESTINGHOUSE SIMPLOT
Figure 10.3-10

10.4 RMA MODELING

The potential effect of component reliability and maintainability on system's availability and on life cycle costs cannot be ignored, particularly in the early design phase. In addition, the plant capacity factor as it is understood in the power generation community provides important criteria in designing for RMA.

In a base load plant such as the reference design, a principle objective is to have the plant available at rated output the highest possible fraction of the time. On the other hand it is drastic to have a base load plant susceptible to any significant number of single failure points such that plant reliability must be very high, even out of reach, in order to pay off in terms of capacity factor. The number of single failure points and the plant capacity factor can be improved by utilizing quasiredundant systems, such as in the combined cycle systems, wherein the increase in the number and cost of maintenance actions is offset by the improved capacity factor.

In the reference design, four coal gasification/gas turbine trains interact with a single steam turbine to comprise the system. Each train is essentially independent and at the time of this analysis, contributes approximately twenty-five percent to the power output, fourteen percent as direct output and eleven percent as output from the steam turbine. Final heat balance iterations may change these ratios, requring adjustments to the model in Phase II. In the event of an independent failure of a single train, then, power output is reduced by approximately twenty-five percent (exclusive of any control make-up). A model for plant availability in terms of various power ratings has been developed which underlines the inherent advantage of the reference design.

For the full plant rating, all gas turbines and the steam turbine must be available, so that a model, to represent the condition is,

$$A_{(100\%)} = SG^4$$

where S is the steam turbine subsystem availability and G is the gas turbine subsystem availability.

If it is assumed that the steam turbine is independent of the gas turbine train, then a binomial model could be used to show the advantage accrued in the reference design. However, there are certain constraints and interdependencies which preclude the use of a simple binomial model. When all the system states are defined in terms of on-off states for the major components and it is recognized that certain states are disallowed because of impracticality, then the model appears as below.

$$a_{100} = SG^4$$

$$a_{75} = 4S(1-G)G^3$$

$$a_{55} = (1-S)G^4$$

$$a_{50} = 6S(1-G)^2G^2$$

$$a_{40} = 4(1-S)(1-G)G^3$$

$$a_{30} = 6(1-S)(1-G)^2G^2$$

$$a_{25} = 4S(1-G)^3G$$

$$a_{15} = 4(1-S)(1-G)^3G$$

where a_i is the system state availability.

The availability of the system is defined as those acceptable system state availabilities, so that:

$$A_{100} = a_{100}$$

$$A_{75} = a_{100} + a_{75}$$

$$A_{50} = a_{100} + a_{75} + a_{55} + a_{50}$$

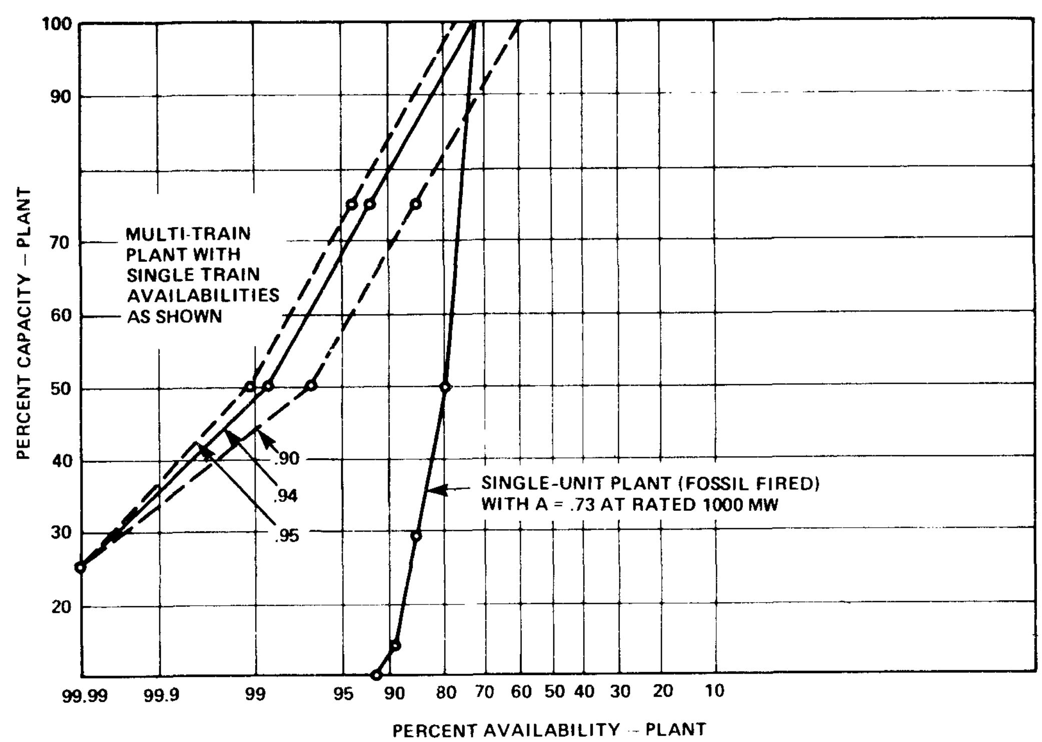
$$A_{25} = a_{100} + a_{75} + a_{55} + a_{50} + a_{40} + a_{30} + a_{25}$$

$$A_{15} = a_{100} + a_{75} + a_{55} + a_{50} + a_{40} + a_{30} + a_{25} + a_{15}$$

The partial sums in the model clearly demonstrate the advantage of the combined cycle systems in terms of accrued availability improvement.

Figure 10.4-1 shows curves which are a plot of plant availability versus output power for various major component availabilities. These example curves point out the possible advantages of the quasiredundant configuration used for the reference design. The curve for the single unit plant shows availability for power output below plant rating improving over rated load performance, but also establishing an availability that reflects all the areas of nonimprovement, such as average stress failures, procedural difficulties, maintenance, complexity, etc., which are not affected by plant output. The corresponding curve for the reference design permits comparison to a single unit plant of size equivalent to the reference design. Starting with an availability of approximately 73 percent for a plant of this size, it is seen that the single unit plant availability may go as high as 92 percent based on FEA data* for a plant of 1/10 size.

*See Figure 1, Page 18, of "A Report on Improving the Productivity of Electric Power Plants", dated March 1975. (Reference No. 1)



AVAILABILITY OF THE REFERENCE DESIGN PLANT
Figure 10.4-1

Comparing this with the curve of A = .94, it is seen that significant improvement in availability is obtained for partial power operation. With an initial reference design availability below the single unit plant availability such as for A = .90, the gains for partial power are so rapid they still show the reference design favorably. If indeed the assumed curve for the single unit plant is reasonable, potentially large gains in plant performance are realizable with the reference design.

CAPACITY FACTOR

Consider these effects on capacity factor. In a base load plant operation the demand tends to approach plant rating. Under these conditions, the plant capacity factor is more directly related to the plant availability and its output capability at that time. This is a decided advantage for the reference design. If one defines an expected value for capacity factor by

$$\widehat{CF} = \sum A_i C_i$$

where A_i is the availability for capacity C_i over the exclusive interval i; then computes for comparison the expected capacity factor for the reference plant and also for the single unit fossil plant, the results shown in Table 10.4-1 are obtained. These results indicate that, for the examples used, a significant gain in capacity factor can be

TABLE 10.4-1
EXPECTED CAPACITY FACTORS

Plant	Single Train Availability		Plant Availability (Rated Output)	Expected Capacity Factor CF
Fossil	---		.73	.81
Comb Cycle	A	.95	.77	.93
	B	.94	.73	.92
	C	.90	.59	.86

realized using the quasiredundant approach of the reference design. Put another way, forced outages and maintenance on the reference design will, for the most part, result in only partial power loss.

For example:

Assume that the single train availabilities are identical:

$$S = .94$$

$$G = .94$$

Plant Availability (Rated Output)

$$A = SG^4 = .94^5 = .73$$

Expected Capacity Factor

$$\hat{CF} = \sum C_i A_i$$

$$= 100a_{100} + 75a_{75} + 55a_{55} + 50a_{50} + 40a_{40} \pm 30a_{30} + 25a_{25} + 15a_{15}$$

$$= 100(.734) + 75(.188) + 55(.047) + 50(.018) + 40(.012) + 30(.001) + 25(.0008) + 15(0) = 91.5\%$$

The impact of this approach has not been assessed in detail, but its potential appears worthy of study. This benefit must be measured against the cost of increased maintenance actions required by the four (4) individual trains. Furthermore, the modelling described above requires in-depth analysis of data as well as model refinement more appropriately done in Phase II where explicit design and performance data will be obtained.

AVAILABILITY DESIGN CRITERIA

Availability goals can be established for the principal units of the reference design using techniques like those described above. In fact, the unit availability of .94 represents a goal, which, when achieved, will result in a system availability comparable to the single unit plant availability shown in Table 10.4-1. Availability goals for the steam turbine subsystem and the gas turbine trains can be apportioned according to their individual reliability/maintainability characteristics, using well known techniques, in conjunction with the FMECA. For example, knowing that:

$$A = A^1 = A^{X_1} . A^{X_2} . A^{X_3} \ldots A^{X_k}$$

where $\sum_k X_k = 1$,

The apportionment for the two (2) different trains becomes

$$A = A^{X_1} . A^{X_2} A^{X_3} A^{X_4} A^{X_5}$$

where the proportionality factors X_k represent the most logical mix based on R, M, A characteristics as seen analytically, and based on realistic appraisals of past performance. Finally, since $X_2 = X_3 = X_4 = X_5$, the availability goals for the reference design become

$$S = A^{X_1}$$

$$G = A^{X_2}$$

For example, if system availability, A, is chosen as .73 (the fossil plant availability shown in Figure 10.4-1), then the availability of each major unit is given by

$$S = .73^{X_1}$$

$$G = .73^{4X_2} \text{ and } X_1 + 4X_2 = 1$$

Assume that, based on complexity and performance history, steam turbine units exhibit higher availability than gas turbines. This results in a normalized steam turbine rating of say $1/2X_2$ so that

$$1/2X_2 + 4X_2 = 1$$

and

$$X_2 = .22$$

$$X_1 = .11$$

Finally the goals for the major units become:

$$S = .73^{.11} = .97, \text{ and}$$

$$G = .73^{.22} = .93$$

The selection of A in the first place will bear significantly on efforts to achieve the unit goals. Trades between unit and system goals using expected capacity factor as an ultimate evaluation are possible. Likewise the optimization of unit number (i.e., how many trains) in a combined cycle system, could be affected by choice of system availability goal, particularly if this goal is defined for the rated output of a base loaded plant.

A basic approach to establishing unit goals in Phase II will be to take full advantage of our experience in these systems and identifying the necessary R and M improvements to achieve an availability goal for rated plant output.

SECTION 11
CONTROLS

11.1 DESIGN CONCEPTS

11.1.1 Gasification Systems

The gasification control system is based upon automatic regulation, depending upon the demand for fuel gas. The feedback control system is sensitive to the demands of the gas turbine without upset of the gasifier because the total gas inventory in the system is relatively small, but the coal inventory in the gasifier is large. The basic control depends upon variations in the demand for fuel gas automatically changing the air flow to the gasifier. Coal inventory in the gasifier is held substantially constant by varying the coal makeup rate to the gasifier.

Equipment design plus instrumentation maintain constant temperature and levels in the gasification system while flow rates are adjusted automatically to meet fuel gas demand.

11.1.2 Power Block

Modular rack-mounted components will be utilized to the extent possible. Subsystem controls will be mounted in distinguishable or separate racks in order to establish system (or subsystem) independence, i.e., CT racks, ST racks and HRSG racks.

Proven hardware and control components will be used to the fullest extent. Analog hardware controllers or microprocessor units reflecting "State of the Art" equipment will be used for primary turbo-generator control. Solid state components, mainly in the form of quickly replaceable modular units, will be used for basic control functions in order to minimize any downtime and facilitate quick and easy maintenance.

Major safety protection systems will be provided as independent control loops separate from the basic control system, examples being HRSG level and over-pressure controls. The use of such protective systems will be in accord with standard power plant practice and codes. A manual trip will be provided for all energy inputs, for example, fuel and steam valve.

11.2 OPERATIONAL REQUIREMENTS

11.2.1 Gasification System

For adequate operation of the gasifier, it is necessary that temperature, pressure and levels be maintained in the gasifier regardless of gas flow. The temperature is maintained in the gasifier by adjusting the steam-air ratio. Too high a steam-air ratio will cause the temperature to drop which will stop ash agglomeration and will eventually adversely influence gasification rate. A low steam-air ratio will cause the temperature to increase causing the ash to slag and eventually plug the fluidized bed. The steam to the gasifier is controlled on the basis of gasifier temperature. The level in the gasifier controls the rate of coal feed to the pretreater. If the level starts to fall, coal is added at a faster rate and conversely a rising level forces the coal addition at a slower rate. The pressure in the system and in the gasifier is a function of the load of the gas fired turbo generator. At high loads, the system pressure will be higher than at low loads. It is anticipated that pressure changes will be relatively gradual.

Other systems such as scrubbing, process waste, heat boiler and gas purification are self-regulating requiring little adjustment for changes in flow. For example, in the Selexol System a change in gas flow rate will be followed by a change in solution circulation rate automatically controlled based upon sulfur leakage to the fuel gas. It may be noted that adequate operation can be obtained with both the scrubber and the Selexol units operating with manual control of circulating rates. The only defect in this method of operation is possible loss in efficiency due to keeping the circulation higher than needed for most of the plant operation.

The Claus unit and water treating unit are controlled on the basis of amount and composition of flow to these units which is the conventional manner of controlling these units.

11.2.2 Power Block

11.2.2.1 CONTROL LEVELS

The control levels will include both basic automatic control which minimizes operator actions and manual control of selected control loops to permit direct operator control to enhance plant availability.

11.2.2.1.1 Manual Control Level

DEFINITION

The manual control level will consist of all the manually controlled systems by either local or remote control devices. It will include all start and stop pushbuttons, local maintenance switches and auto-manual stations for the control of valves and other actuator positions.

Manual control functions which include a potential for equipment damage or system disturbances by improper or ill-timed operator input will be subject to overrides and limits beyond the operator's control.

APPLICATION

Sufficient field and control room devices will be provided for the sequencing of equipment through the various steady state modes by the operator or operators. This will include selected forced automatic sequencing of critical components.

It is assumed that all transitions from steady state modes will require, at least, operator initiation, with the practical exception of protective actions which can be generated within the overall control system structure. Certain transitions will require complete operator initiation, sequencing and monitoring such as the transition of the cold plant to a hot, ready-to-start condition.

The operator will be provided with the necessary indicating and recording devices to monitor selected functions in the manual level.

11.2.2.1.2 Automatic

DEFINITION

The automatic control will permit the operator to control the unit(s) from the central control room. Provision will be included to permit starting and loading of the turbo generators and their associated HRSGs with a minimum of operator input.

The automatic control level will include such automatic functions as startup acceleration control, load control, level control for the HRSGs, steam turbine valve control and a digital information and display system.

Experience has indicated that the level of automation proposed here is adequate for an attended, base loaded plant. Increased automation for intermediate load operation can be provided as an option.

APPLICATION

The operator will interface the system via the various automatic control level devices on the operator's consoles. Auto-manual stations will be used for those control loops to be used in both the automatic and manual control levels. These stations will be provided for such loops as load control, HRSG level control and selected steam valve control.

11.2.2.1.2.1 COMBUSTION TURBINE CONTROL - THE POWERLOGIC CONTROL SYSTEM

GENERAL

The combustion turbine control system is a solid state system which provides centralized automatic speed and temperature control for combustion turbine generators at all stages of operation from no load to maximum load capability. It continuously monitors selected analog values and contact status, and signals an alarm when safe operating limits are exceeded or when any serious plant disturbance occurs. When necessary or desirable, it also permits the operator to control conditions in the plant by changes made at the operator's console.

Control is based on a speed/load governor and a fuel limit which are computed from turbine speed, combustor shell pressure, generator load and temperature at various points in the system. Provisions are made for maintenance cycle temperature, turbine generator speed, load and loading rate; for controlling acceleration during starting and bringing the turbine to full speed within a fixed interval of time and for maintaining compressor surge margin.

OPERATION

To minimize startup time, devices will be started in parallel whenever possible. However, when one action is dependent on the completion of another, the control system will receive a completion signal which initiates the next action. Startup of the turbine will be accomplished within a specified time interval or shutdown will occur to protect the unit. Continuous time checks are made during the starting sequence to alert the operator to possible acceleration time overruns.

For maintenance operations, the operator may choose to halt the starting sequence at two hold points to permit manual adjustments. The two hold points occur (1) prior to ignition with starting device on and (2) at synchronous speed and no load. The operator may also select visual displays of information such as temperature, voltages or pressure levels. The system may be either manually or automatically synchronized depending upon the selection of the operator.

The Automatic Generator Synchronization System will automatically raise and lower the speed and adjust generator voltage to match the line frequency and voltage. When this is accomplished, the synchronizer will automatically close the system breaker as permitted by the Synchro-Acceptor. The Synchro-Acceptor recognizes only a particular zone of circuit closing as acceptable. This zone is broad enough to permit a choice of phase angle and rate of change of phase angle by the automatic synchronizer, yet it is narrow enough to prevent closing in situations that would constitute malperformance of the synchronizing system. The phase angle is displayed on the synchroscope on the operator's panel and is used to supply information to the operator who elects to accomplish synchronization under manual control. When the breaker is closed, the combustion turbine picks up an increment of load (minimum load). The operator can load the combustion turbine in several ways at his option. The most common for base load operation will be to select "Temperature Control" and the temperature control limit "Base" or "Peak." In this mode, the combustion turbine will automatically ramp to load using speed droop control up to the temperature limit which varies with a measured combustor shell pressure. The result is that the load will vary with the combustor shell pressure which, in turn, varies with the ambient temperature. If the operator desires part load output, the combustion turbine will be loaded using a droop speed governor. The required part load may be obtained several ways. A "Stop Load" pushbutton may be depressed as the combustion turbine is automatically loading up to the temperature limit and this will hold the load. To resume the "Go" button must be depressed. Also, the operator can select "Speed Control" instead of "Temperature Control" and use the "Load Raise" or "Load Lower" pushbuttons to obtain the desired load. During part load operations, the load will change with system frequency but is not allowed to exceed the temperature limit (Base or Peak) that has been selected.

The combustion turbine is also protected during loading by a "fuel limit" override control depending on the combustor shell pressure value. The combustion turbine system can be shut down in several ways by the operator. A "Normal Stop" pushbutton can be depressed, and the combustion turbine will unload at the same rate as the loading phase. When minimum load is reached the breaker will open and the combustion turbine will remain at synchronous speed for three minutes. At the end of three minutes, the fuel valves will be closed, the combustion turbine will coast down to the turning gear, ready to restart. The operator can take the load off of the combustion turbine by depressing the "Trip" pushbutton. The breaker will be opened and the fuel valves will be closed.

Protection functions are an integral part of the control system. Depending on the type of problem and the "level" or value of the parameter indicating the problem, the control system will automatically take one of the following actions:

(a) "Alarm"

- warn the operator of an impending problem or a problem that requires his attention

(b) "Auto Unload"

- the control system will unload the combustion turbine at the normal rate until the problem is corrected. If it is not corrected by the time the combustion turbine reaches minimum load, the turbine will shut down in a normal manner.

(c) "Generator Breaker Open"

- this action is mostly caused by a protective relay device and only recognized by the control system. The control system will hold the unit at synchronous speed ready to resynchronize upon operator action.

(d) "Fast Shutdown"

- this action is to open the generator breaker and proceed with a normal shutdown, i.e., operate at synchronous speed for three minutes and then close the fuel valves.

(e) "Load Dump"

- the control system will open the generator breaker and if the fault does not clear within a short period of time, the turbine will be tripped.

(f) "Trip"

- the control system will open the generator breaker and close the fuel valves at the same time.

11.2.2.1.2.2 STEAM TURBINE CONTROL - DIGITAL ELECTRO-HYDRAULIC SYSTEM

DEFINITION

A Digital Electro-Hydraulic control system, with several years of operating experience, has demonstrated the advantages of combining a programmable digital controller with an analog control system. The control system uses the digital controller's ability to monitor, memorize, calculate, and make decisions instantly to provide faster more accurate steam turbine control than was previously possible with manually controlled mechanical hydraulic systems. The manual analog backup system is physically separated from the automatic digital system. This enables on-line maintenance.

In the event of a system failure, the manual backup system is activated automatically. The operator controls the turbine and receives his information from the operator's panels located on the main control board. A cathode ray tube (CRT) and a typewriter are provided for a greater display of information and messages to the operator. Preassembled cables connect the panels, CRT and the typewriter to the digital controller.

OPERATION

The steam enters the high pressure cylinder via throttle and governing valves. From the high pressure cylinder exhaust end the steam flows into the reheater section of the boiler and re-enters the turbine via reheat stop and interceptor valves. The spring loaded valves are positioned by hydraulic actuators which receive their motive fluid from a high pressure fluid supply system. In the event of an overspeed condition, loss of pressure in the overspeed trip header is reflected in the autostop trip header by means of a diaphragm valve.

The digital controller positions the throttle and governing valves by means of electro-hydraulic servo loops. In the event of a partial load drop, the interceptor valves are closed by energizing a solenoid valve on the appropriate valve actuators. The digital controller receives three feedbacks from the turbine: speed, generator megawatt output and first-stage pressure, which is proportional to turbine load.

To start the turbine, the operator must ensure that the turbine has been operating on turning gear and that minimum vacuum is established. Then he must latch the turbine via the Latch pushbutton on the control panel. The governing, reheat stop, and interceptor valves move into full open position. The throttle valves stay closed. The turbine generator is brought up to 3300 rpm by opening a small internal bypass valve (pilot valve) of the throttle valve. At 2200 rpm, speed control is transferred from throttle valve to governing valve control. The transfer is initiated by the operator but accomplished automatically. The turbine generator is accelerated to synchronous speed by opening the governor valves. The generator is synchronized to the bus either manually or by an automatic synchronizer which is provided as a standard part of the system.

When the main generator breaker is closed, the control system initiates 5 percent load automatically. This avoids motoring of the turbine by the generator. After Latching the turbine, the "Automatic Turbine Control" (ATC) program will perform the above acceleration and loading automatically if it is put into service by the operator.

11.2.2.1.2.3 DATA DISPLAY

Data display (in addition to that available to the operator on the main control panels) will include digital display of speed, megawatt and other vital control parameters on an operator's information panel. Information in the form of alarm and trip reviews, block trending data, periodic and demand data logs will be displayed (and can be output for a permanent record as an option) at the operator's command. A CRT will be used for this primary digital display. Proven Pace-type control hardware, along with field equipment such as microprocessor data acquisition subsystems, will be used to implement this control level.

11.2.2.2 REDUNDANCY

11.2.2.2.1 General

Redundancy, in general, is achieved in that the control system has an automatic and a manual control level. Using hardwired manual control in selected control loops will give an operator (or operators) direct control of selected variables such as turbine loading and HRSG level controls. More specifically, such control elements as power supplies, speed pickups and combustor shell pressure sensors are redundant. There are sixteen (16) each of blade path and exhaust thermocouples such that no one thermocouple failure will cause a turbine trip. The control loops in themselves are also somewhat redundant, in that the temperature control loops back up the speed and load loops. Discretion will be used in selection of elements which service both automatic and manual systems without redundancy. The decision to employ such unredundant services will depend on engineering judgment and trade-offs of cost, reliability, failure effects and time to isolate and repair failures. Obviously, any such device may, if appropriate, be redundant within itself in order to achieve required reliability, even though it is used unredundantly at a system level. Such items as duplex thermocouples would be examples of this latter case.

11.2.2.3 APPLICATION

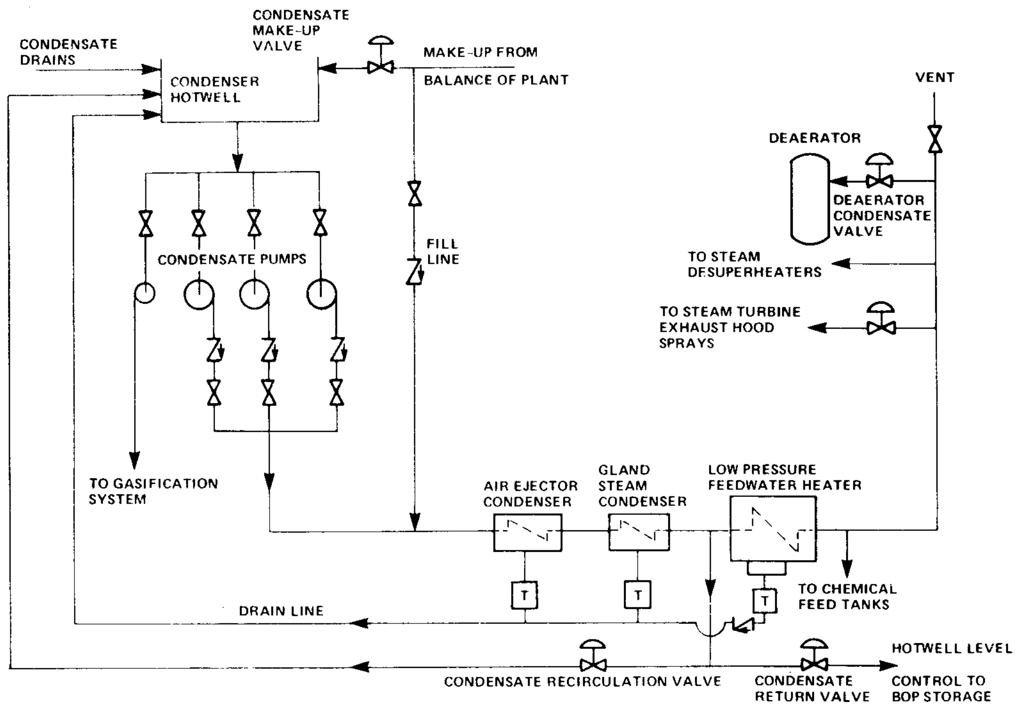
This section describes the main functions of the control system as applied to the operation of startup and operation of the power block.

11.2.2.3.1 HRSG Condensate Control

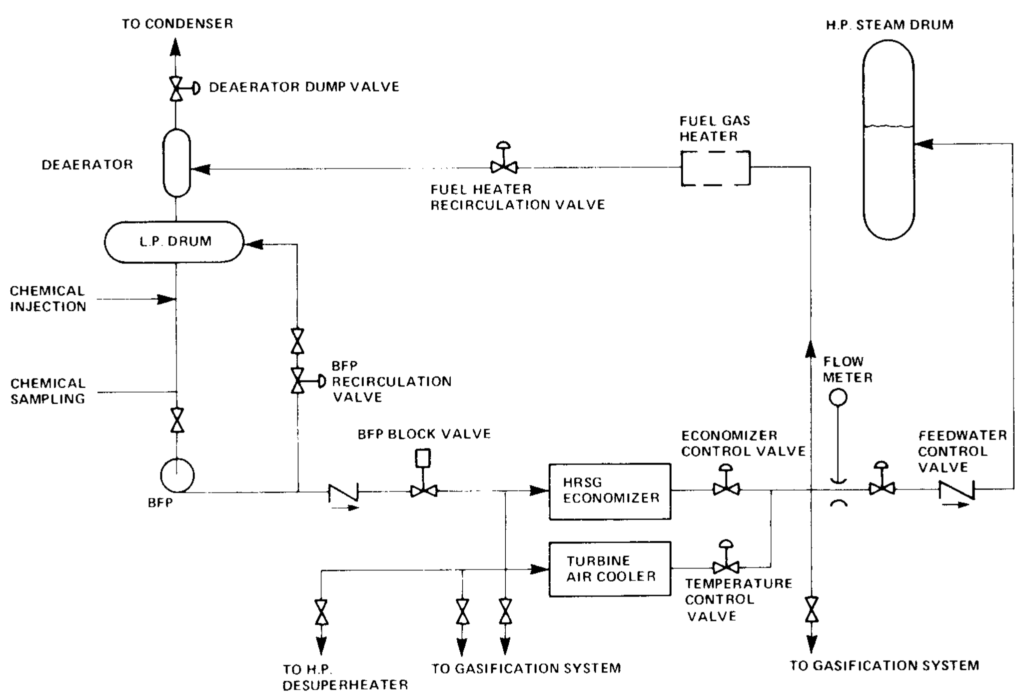
Referring to Figure 11.2-1, the condensate recirculation valve ensures that sufficient cooling flow is always passing through the air ejector and gland steam condensers. The condensate makeup valve opens as required to maintain constant "normal" hotwell level. However, "normal" level setpoint is biased downward by the summation of LP drum level errors indicating that the total water stored in the LP drums is greater than normal. The condensate return valve opens only when hotwell level rises to a preset amount above the biased level setpoint. The various desuperheater and exhaust hood spray condensate valves will have the normal temperature control, condensate spray pressure control, and/or On-Off logical control. Each of the HRSG deaerator condensate valves will be under independent three element control using the variables of total HRSG and WHB superheater outlet steam flow, deaerator condensate flow and LP drum level.

11.2.2.3.2 HRSG Feedwater Control

Referring to Figure 11.2-2, the BFP recirculation valve ensures that sufficient cooling flow is always passing through the boiler feed pump, BFP. It can also serve to limit



CONDENSATE SYSTEM
Figure 11.2-1



HRSG FEED SYSTEM
Figure 11.2-2

feedwater pressure at low flows. The discharge check valve prevents backflow from the economizers, etc., in the event of BFP shutdown.

In addition to service as a positive shutoff valve in the pump discharge, the BFP motorized block valve is used during pump startup to limit total pump flow into empty economizers, etc., and thereby prevent pump cavitation. The turbine air cooler requires feedwater flow whenever the gas turbine is running. The required cooling air temperature will be maintained by the turbine air cooler temperature control valve sensing cooler air discharge temperature. Either a variable or fixed setpoint can be provided depending on the requirements of the combustion turbine's hot parts. When neither the HRSG nor the gasification system is using feedwater, the discharge flow from the turbine air cooler temperature control valve will return to the deaerator via the gas fuel heater and its downstream fuel heater recirculation valve. This valve will be a cavitation resistant high pressure drop valve and will be operated as a feedwater pressure control valve set about 50 psi below normal full load feedwater pressure. This pressure control valve will automatically open to maintain a sufficiently low back pressure for the air cooler temperature control valve as it opens to control cooling air temperature. Then as the HRSG and gasifier WHB economizers begin passing sufficient total flow to raise the feedwater pressure above the setpoint of the fuel heater recirculation valve, it will finally open fully so as to pass the design flow for fuel gas heating.

Both the HRSG economizer and the gasification WHB economizers will have low-pressure drop control valves located downstream or possibly upstream. The upstream location could be used if it were desirable to limit economizer pressure below the shutoff head of the BFP. These two economizer control valves will provide the capability of ratio control of the flows to the economizers for startup and for optimizing the cycle efficiency. This might be done using feedwater discharge temperatures from the two economizers. The two economizer valves can also be used during startup to limit deaerator energy input by reducing the flow through the economizers when steam and condensate flows are low and economizer gas side temperatures are high. This is a normal condition for startup of the second, third, and fourth HRSG as each is brought up to match the steam pressures of the high pressure steam header. Any such reduction of economizer flows can be accomplished automatically by use of an override controller sensing deaerator pressure above a setpoint.

Feedwater control for each of the HP drums will utilize the three elements: superheater outlet steam flow, feedwater flow, and HP drum level. The feedwater valves will have equal percentage trim with very low shutoff leakage to provide automatic control from startup to full load.

11.2.2.3.3 Steam Control

STARTUP OF FIRST UNIT

The steam plant startup is initiated by starting one combustion turbine-HRSG-gasifier unit and bypassing its total steam flow until proper steam conditions for steam turbine startup are achieved. For such an initial unit startup, the various steam valves shown on Figure 11.2-3 will be controlled as follows:

1. The following valves are fully opened prior to combustion turbine startup:

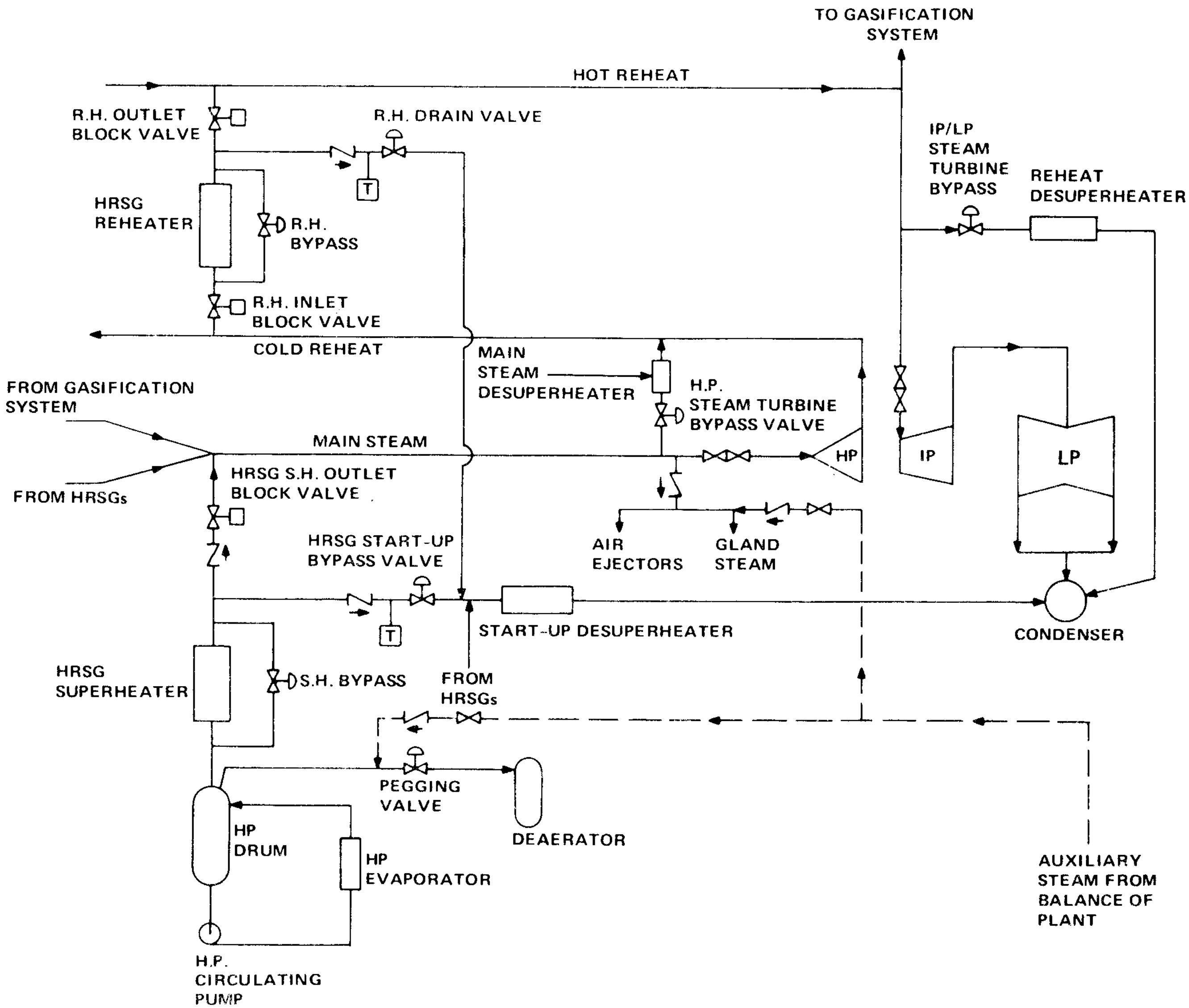
   - HRSG superheater outlet block valve
   - HRSG reheater inlet block valve
   - HRSG reheater outlet block valve

2. The HRSG startup bypass valve will open fully as soon as steam pressure is sufficiently high to ensure that the HP drum is vented of air. Opening of this valve drains any water condensed in the superheater by the combustion turbine spin to ignition speed. The valve remains open until a set minimum steam flow is passing into the main steam header.

3. The HRSG reheater drain valve will open and close synchronously with the HRSG startup bypass valve.

4. The HP steam turbine bypass valve will be a throttle pressure control valve. Its setpoint will be variable from a low value up to a value somewhat above rated throttle pressure. The setpoint ramping would probably be as a function of plant total superheater outlet steam flow so as to maintain temperature margins as the HRSG superheater and main steam piping are heated. Its setpoint may also be adjusted during steam turbine startup and loading to assist in the control of throttle steam temperature to match the requirements of steam turbine metal.

5. The IP/LP steam turbine bypass valve will be operated as a pressure control valve with its full open size approximating the flow versus steam pressure characteristics of the steam turbine IP/LP units. Pressure setpoint will be a variable function of plant total superheater outlet steam flow. This will cause reheater pressure to vary almost as if it were connected to the steam turbine and will thereby maintain normal reheater and piping flow velocities as the steam turbine flow is varied from zero to 100% of available steam.



POWER BLOCK STEAM SYSTEM
Figure 11.2-3

6. Both the HRSG superheater and reheater will have temperature controlled bypass valves. These will remain closed until their associated steam temperatures reach their setpoints as the combustion turbine is loaded. Each valve's temperature controller will have independently variable setpoints to provide throttle and reheat steam at proper temperatures for startup and loading of the steam turbine.

7. With each steam turbine bypass valve (HP and IP/LP) is an associated automatic temperature controlled desuperheater. Temperature setpoints would be selected or variable as required by the desuperheater downstream saturation pressures.

STARTUP OF SUBSEQUENT UNITS

After the first combustion turbine-HRSG-gasifier unit has been started, the startup of the remaining units proceeds sequentially. The period of time between subsequent unit starts is determined by the operator and dispatcher on the basis of required plant loading rate. If the required plant loading rate is low enough so that the steam turbine will not exceed its allowed rates of temperature increase and loading, the combustion turbines can be started and loaded at a rate such that the main steam and reheat steam bypass valves will remain closed. Otherwise, the subsequent units can be started and loaded at rates subject only to their own limitations and the operator's ability to coordinate them. Whenever steam production increase exceeds the loading rate of the steam turbine, the excess will be passed by the HP and IP/LP steam turbine bypass valves, both operating as pressure control valves.

For each such subsequent unit startup, the steam valves will be controlled as follows:

1. The HRSG superheater outlet block valve can be opened at combustion turbine startup.

2. The HRSG reheater outlet block valve opens fully if the inlet block valve is cracked open and the combustion turbine exhaust temperature is above the saturation temperature corresponding to cold reheat pressure.

3. The HRSG startup bypass valve functions as discussed above for the initial unit startup. The valve is sized to allow sufficient steam flow so that the throttle temperature is not excessively depressed when the superheater outlet steam begins to flow into the main header.

4. The HRSG reheat drain valve functions as discussed above for the initial unit startup.

5. The HRSG reheater inlet block valve will be motorized with the abilities to be ramped in either direction at a slow rate and to be held at any intermediate position. Logical protective control could be as follows:

   - Valve ramped closed when combustion turbine load less than MIN LOAD.

   - Valve permitted to open when HRSG superheater outlet steam flow exceeds a setpoint.

   - Valve permitted to close when HRSG superheater outlet steam flow is less than a setpoint.

   - Valve ramped open when cold reheat pressure exceeds a variable setpoint which will be related to steam turbine impulse pressure. This will prevent excessive flow through any other reheaters that are already in service.

   The operator would use the valve to control reheater steam flow so as to minimize steam turbine hot reheat (inlet) steam temperature rates of change.

6. The HP steam turbine bypass, functioning as a pressure control valve, will remain closed unless the throttle steam pressure exceeds the existing setpoint. Then it will open and control throttle pressure at the desired setpoint.

7. The IP/LP steam turbine bypass, functioning as a pressure control valve, will remain closed unless the cold reheat pressure exceeds the existing setpoint.

8. Both HRSG superheater and reheater temperature control bypass valves will function as discussed above for the initial unit startup.

SHUTDOWN OF A UNIT

Shutdown of a combustion turbine-HRSG-gasifier unit is done in such a way as to maintain combustion turbine exhaust temperature as high as possible. This is done by reducing combustion turbine load with the inlet guide vanes automatically controlling blade path temperature at the exhaust temperature reference. Until the inlet guide vanes are fully closed and exhaust temperature begins to fall, superheater and reheater outlet temperatures can probably be maintained constant by the operation of the superheater and reheater bypass valve controlling to their 1000°F setpoints. Once the inlet guide vanes and the superheater and reheater bypass valves are fully closed, the superheater outlet and reheater outlet steam temperatures will begin to drop. Depending on the number of units in operation and the amount of steam being produced by the unit being shutdown, the main and reheat mixed steam temperatures to the steam turbine will begin to drop. The effect of the reheater temperature drop can be offset by proportional closing of the reheater inlet block valve as the HRSG superheater steam flow drops. Excessive throttle temperature decrease can be prevented by closing the superheater outlet motorized block valve. At the same time, the HRSG startup bypass valve would automatically open as steam flow dropped to the set minimum. Closing of the reheater outlet block valve would take place as soon as the inlet block valve reached full closure but not later than the point at which the combustion turbine exhaust temperature approaches saturation temperature corresponding to cold reheat pressure. Thus for the case of a combustion turbine trip from load, the reheater output block valve would be closed immediately to prevent passage of water condensed by the cooling action of the combustion turbine exhaust as it decelerates.

UNSCHEDULED SHUTDOWN OF STEAM TURBINE

For any shutdown of the steam turbine, the HP and IP/LP steam turbine bypass valves will both open as their respective pressure controllers sense main and reheat steam pressures rising to their setpoints. With setpoints only a little higher than operating pressures, these valves will prevent excessive disturbances of the HRSG and will permit continued operation of combustion turbines at up to their rated loads.

Each HRSG deaerator will have a pegging valve to supply steam from the HP drum when necessary. Its primary purpose is maintaining deaerator pressure just above atmospheric pressure over the plant load range where insufficient energy is available from all other sources. It will also be controlled to perform the important secondary function of preventing boiler feed pump cavitation during periods of decaying deaerator pressure. This will be especially important when tripping of the steam turbine causes immediate reduction of the two extraction steam flows which provide energy to the deaerator. The pegging valve pressure controller setpoint will be variable. For the primary function, its setpoint will drop to its minimum just above atmospheric pressure. Whenever deaerator pressure rises above the set minimum, the setpoint will track to be just slightly below the actual deaerator pressure. The tracking rate, up and down, will be set such that when the deaerator pressure drops to the setpoint, the pegging valve will control at the setpoint and the setpoint will continue to decay at a rate compatible with the needs of the boiler feed pump.

11.2.2.3.4 Combustion Turbine/Gasifier Coordination

INDEPENDENT STARTUPS

The combustion turbine will be started and loaded to a selected load using the standard automatic control system and burning No. 2 distillate fuel. Unless there is an emergency need for power, this will not be done until after the coal gasifier has been started and is producing a set minimum flow of clean coal gas. This gas will be flared through a pressure controlled dump valve capable of passing one-third of the full load gas flow at a gas pressure of about 120 the full load gas flow at a gas pressure of about 120 psia. Until the combustion turbine is started, this gas pressure will be less than 30 psia and the dump valve pressure setting will be set to cause the valve to open fully. During the gasifier startup, the gasifier booster compressor suction pipe will receive its air through a check valve connected to atmosphere or to a starting blower. The combustion turbine's bleed air connection to this same suction piping will be initially closed off by a flow control valve.

FUEL TRANSFER

After the combustion turbine has been accelerated, synchronized and loaded as required to initiate transfer from distillate to coal gas, the flow setpoint of the bleed air control valve will be ramped up at a rate compatible with the characteristics of the gasifier. This will cause the pressure levels throughout the gasifier to rise until the bleed valve is full open and the gasifier output pressure is 20 to 40 psi above the combustor shell pressure. Ramping of the bleed valve's flow setting will be terminated at a setpoint chosen to protect the combustion turbine against excess air extraction. During the period of rising pressure levels in the gasifier, the flare dump valve will remain wide open, but its pressure setpoint will be caused to track thegasifier pressure so that it will be ready to hold constant gasifier discharge pressure during the fuel transfer.

The combustion turbine's transfer from distillate to gas fuel can be best done under megawatt control so that the combustor shell pressure will remain essentially constant. The transfer would be complete in less than a minute with the distillate flow reduced to zero, the gas throttle valve opened enough to hold the set load, and the flare dump valve closed enough to hold the set gasifier discharge pressure.

After the transfer, the pressure setpoint of the flare dump valve would be ramped up to a maximum just above the normal operating pressure at full plant load. This will cause the dump valve to finish closing and the gasifier's various zone pressures to rise to new equilibrium values. If the megawatt setpoint is unchanged, the combustion turbine's gas throttle valve will close some and this will be a factor contributing to the final equilibrium pressure of the coal gas.

LOADING

The combustion turbine/gasifier combination is loaded by controlled opening of the gas throttle valve responding to the speed controller or megawatt load controller. Regardless of the operator's mode selection, there are inherent limits on the load step size and load ramp rate. For example, any increase in throttle valve opening causes two immediate effects relating to the gasifier. It increases the gas flow and the combustor shell pressure. The combustor shell pressure rise reduces the throttle valve available pressure drop so that at any given gasifier pressure there is only a limited step increase in combustor shell pressure possible. Further increase in throttle valve opening will simply cause no further "instantaneous" increase in load.

The combustor shell pressure rise also causes an increase in the bleed air flow, but because of the gasifier's gas storage volumes there will be a period of time between the shell pressure rise and the subsequent rise of the gasifier's discharge pressure to its new, steady-stage value. Thus the gasifier's volume time constant will limit the load ramp rate. These inherent limits on step size and ramp rate may be more restrictive than the similar limits provided to protect the combustion turbine against excessive thermal stress.

UNLOADING AND TRIPPING

The effect of any reduction in opening of the combustion turbine's throttle valve is to cause an immediate reduction in throttle gas and bleed air flows. Because of the gasifier's storage volumes, it is possible that bleed air flow could experience a transient reduction to near zero flow (check valve closed) unless the booster compressor's pressure ratio versus flow characteristics are selected to compensate for the combustor shell reduction during the period of decline of gasifier pressure to its final equilibrium value. If necessary, the gasifier flare dump valve can be used to accelerate the reduction in gasifier pressure as an aid to sustaining bleed air flow into the gasifier during extreme load reductions.

In case of a gasifier failure tending to increase bleed air flow, the bleed air flow controller will act to control the flow at the upper limit setting. Also, additional logical control can be provided to ramp down the flow setting for gasifier hot standby or shutdown in conjunction with operation of the flare valve to reduce pressure in the gasifier and maintain minimum flows in the gasifier system.

11.3 CONTROL PANELS

11.3.1 Gasification System

The control panels will indicate the position of process variables for each transmitter and local controller. Transmission of process variables to the control panel shall be by pneumatic, electric or thermocouple type instruments and no process fluid except air shall be piped to the control panel.

In addition to instrumentation indicating or controlling process variables, the control system will include:

1) A data logging mechanism.

2) An alarm annunciator system.

3) An automatic sequencer for coal lock hopper system.

4) An emergency power supply in case of power failure.

5) An indicating system showing which motor drives are actuated.

6) Two-way communication with all sections and services of the plant.

11.3.2 Power Block

11.3.2.1 TYPICAL CONSTRUCTION

11.3.2.1.1 General

The following description of the control consoles is typical for all subsystem panels. The combustion turbine's Powerlogic remote operator's panel and the steam turbine's standard system panels, including the steam turbine control display and CRT panels, will be incorporated into these existing consoles. To complete the operator interface panels, an operator information panel will provide digital display (including a CRT) of combustion turbine, HRSG, and other power block variables.

DESCRIPTION

Boiler-Turbine-Generator Control Consoles or BTG Boards are the main operator-to-plant interface. From these control consoles, the operator can control the whole plant, or various subsystems of the plant, in either of the control operating levels. There is a separate BTG control console for each combustion turbine/generator/ HRSG combination, one for the steam turbine/generator/hotwell combination, one for the steam turbine digital electrohydraulic system, and a console for the plant electrics and auxiliary systems.

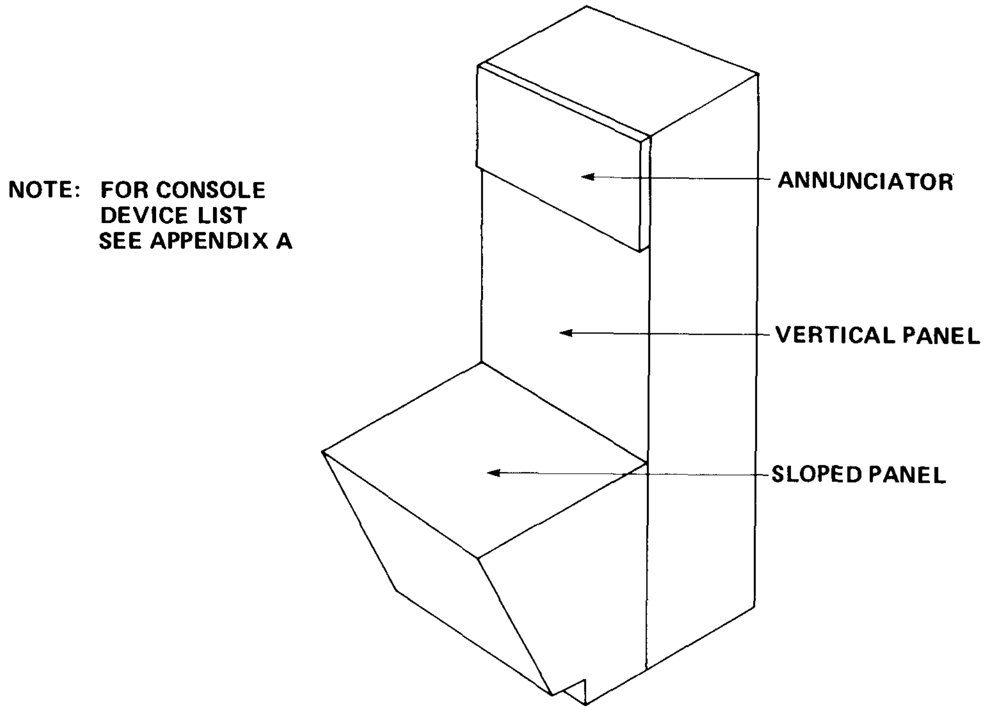
The control consoles are centrally located in the Control Room. They are arranged side by side in order to keep them in the closest proximity.

The BTG control consoles are cabinets which house the pushbuttons, selector switches, meters and recorders that provide the operator with plant control and information. The BTG consoles are divided into three major areas—the sloped, vertical and annunciator panel sections.

Figure 11.3-1 shows the basic outline and profile of the BTG control consoles.

DESIGN PHILOSOPHY

The BTG control consoles will be designed so that the operators can accomplish the entire plant startup from hot, ready-to-start to power generation, or the plant shutdown from power generation to hot, ready-to-start during normal plant conditions.



TYPICAL BTG OPERATOR CONSOLE
Figure 11.3-1

Sufficient operator interface concerning direct motor and valve control will be provided in order to increase plant availability. Hardwired indicators, recorders and fault annunciators have been incorporated into the control consoles to give the operator sufficient visibility of the plant condition while in the manual control level.

11.4 POWER SUPPLIES

11.4.1 Power Supplies - Gasification System

Instruments and fractional horsepower motors used to drive controllers and recorders require a reliable source of power. A power failure at the control room may cause a plant upset as well as some damage. To compensate for possible power interruption, an emergency source of power is provided. A reliable power source for the control center will allow the orderly shutdown of the gasification plant in cases of power failure. The emergency source may take the form of a deisel generator set with automatic start in case of power failure.

11.4.2 Power Block

The basic power source will be 125 VDC station battery for C. T. turning gear and emergency lube oil pump. DC-to-DC power supplies will provide the analog system power which will be ±15 VDC. The digital logic associated with the analog control system will be CMOS type using the same ±15 volt supplies as the analog system.

Contact inputs to the analog/digital system will be powered by 25 volts DC or greater. Field transmitters will be powered by 24 VDC.

Power supplies will be switching types utilizing 125 volt input. No inverters will be required to power control equipment.

Redundancy will be provided by dual power supplies and diode crossover networks. See Figure 11.4-1.

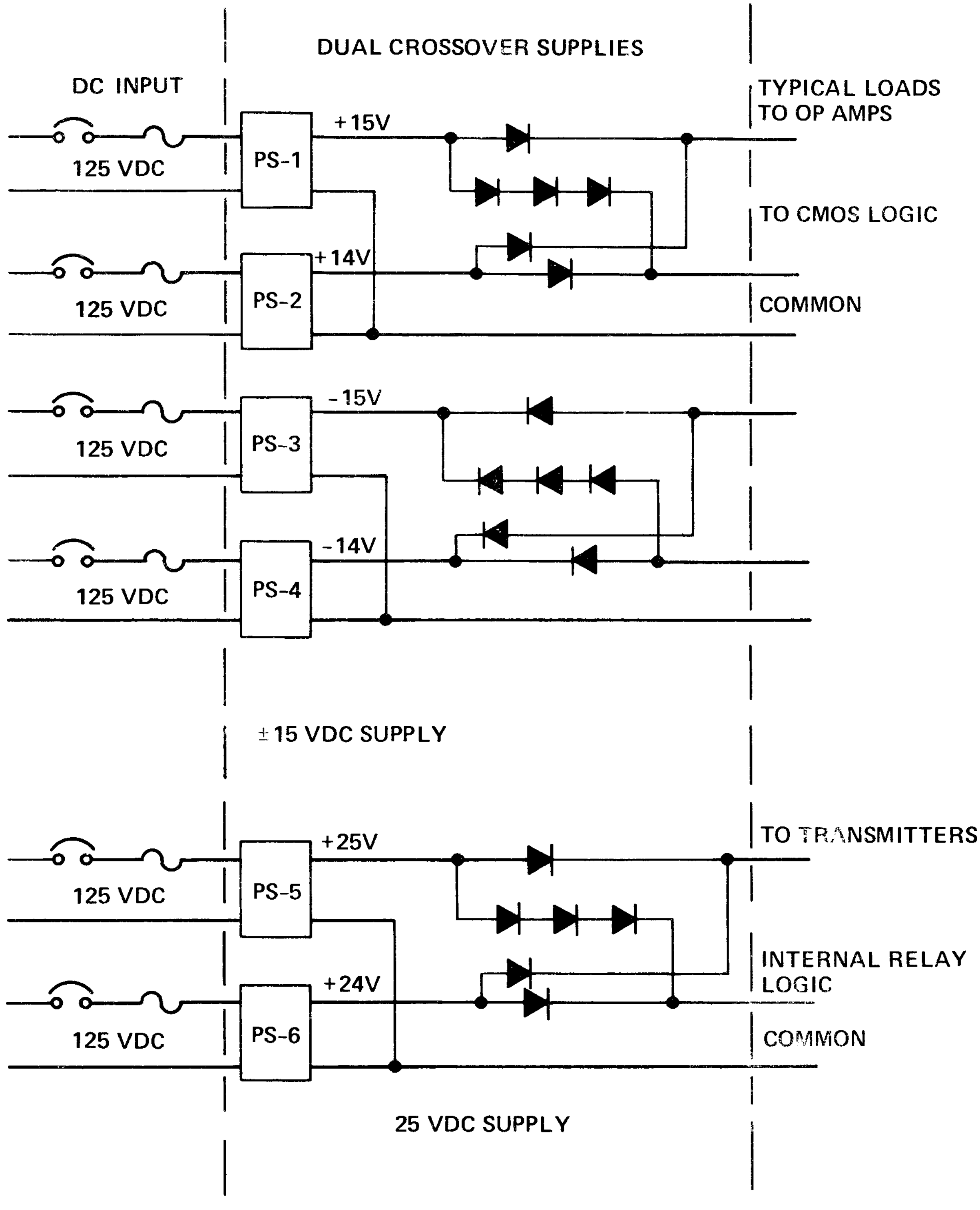
Control equipment requiring 60 Hz AC will be avoided to eliminate requirement for inverters.

11.5 ALARMS AND TRIPS

11.5.1 Gasification System

The following conditions will be annunciated:

Alarm Condition	Type
1. High pressure in gasifier	Alarm
2. High temperature in gasifier	Alarm, trip
3. Low temperature in gasifier	Alarm
4. Power supply failure	Alarm, trip
5. Loss of boiler feed water	Alarm, trip
6. High level in gasifier	Alarm, trip
7. High level in pre-treater	Alarm, trip
8. Low level in gasifier	Alarm, trip
9. Low level in pre-treater	Alarm, trip
10. Loss of steam to gasifier	Alarm, trip
11. Loss of steam to Selexol unit	Alarm
12. High contaminant in the fuel gas	Alarm
13. Loss of cooling water	Alarm, trip
14. Low heating value of the gas	Alarm
15. Loss of air to gasifier	Alarm
16. Loss of air to pre-treater	Alarm
17. Low temperature of fuel gas	Alarm
18. High temperature in pre-treater	Alarm, trip



TYPICAL REDUNDANT POWER SUPPLY ARRANGEMENT
Figure 11.4-1

11.5.2 Power Block

11.5.2.1 LEVELS DEFINITION

The plant trip system will be designed to minimize the effect of an undesirable event on the entire plant. Each subsystem will have its own internal trip system which will enable the operator or the protective system to trip it independent of the rest of the plant. For example, the combustion turbine #1 trip logic can trip combustion turbine #1, but the other combustion turbines and the steam turbine will continue to produce power.

However, due to the nature of combined systems, the effect of one subsystem upon the other is very significant. Therefore, the plant trip system will place restrictions on the independence of the various subsystem trip schemes. Individual subsystem protective systems will be designed and implemented to maximize the power generating capability of the plant, while at the same time being commensurate with required machinery protection. Since the plant is an attended station, certain tripping functions will be left to the discretion of the operator. However, much hardware annunciation of fault conditions is provided for operator information. Two level alarms are provided on many functions to inform the operator of impending trips where it is felt that proper operator action can prevent a trip from actually occurring. Following a trip, the operator shall be required to manually reset the trip circuits. Faults or previous trip conditions that are not cleared or reset will be brought to the attention of the operator through the annunciator, the BTG status and PB lights or the CRT on the Information System.

11.5.2.2 ANNUNCIATORS

The annunciators are provided to give operating personnel visual and audible fault indication. The annunciators are located in the upper section of each BTG Board, at other locations inside the control room and at local control panels in other plant areas. Fault indications that are contained on the local panels are grouped and associated with an alarm on the BTG board annunciators. This gives operating personnel in the control room knowledge of the local fault indication. All known trip conditions will be alarmed.

Two level alarms (high and high trip) will be provided on selected functions and equipment to warn the operator of imminent or possible trips so that appropriate corrective action may be taken to help keep the plant at load and/or on-line.

The BTG board annunciators provided will be solid-state annunciators. The overall dimensions of the annunciator will depend upon the final number of alarms required. Space on the BTG operator's consoles will be provided for 120 alarms arranged in eight (8) columns of 15 windows each. The columns will be divided into rows with

3 windows to a group. Currently, it appears that only four (4) groups of three (3) windows will be needed (a total of 96 windows). This can be expanded to the maximum of 120 if the need arises. Each window is approximately 7/8" high by 3-1/4" wide. Each window is backlighted with two (2) 3-watt lamps which are rated for 50,000 hours of operation. The annunciator is powered by 125 VDC. The annunciators accept a 125-volt DC signal from field contacts for fault indication. The annunciator can accept fault indication from either normally open or normally closed field contacts. A slide switch at the back of each alarm module permits easy changeover from normally open to normally closed. The current plant design philosophy dictates that all field contacts be of the normally closed, open to alarm type, except where conflicts with existing control would necessitate extensive changes (as would be the case in generator breaker control, for example).

The operating sequence of the alarm panel is designated TFS, which signifies a special sequence with coded flashing to indicate the initial or "first out" alarm.

The initial alarm will trigger an audible alarm and will appear on the panel as an intermittent fast flash. Upon acknowledgement of the alarm, the audible signal is silenced and the panel light assumes a regular slow flash. Subsequent alarms will again trigger the audible alarm and will appear on the panel as a steady, fast flash. After resetting the "first out" system, the panel light goes to a "steady on" condition in which it remains until the fault is corrected. For typical alarm and trip list see Appendix B.

11.6 INSTRUMENTATION AND CONTROLS

11.6.1 Gasification System

The gasification system will require the following controls:

1) Coal lock-hopper automatic sequencer rate actuated by the level in the treater.

2) Air flow to the gasifier is controlled.

3) Steam control to the gasifier to maintain a constant ratio with the air flow reset by gasifier temperature.

4) Level control in the gasifier adjusts the rate of coal injection from treater.

5) Steam attemperation in the process waste heat boiler to limit superheat temperature.

6) Circulation control of Selexol solvent adjusted by sulfur content in the fuel gas.

7) Flow control of the steam to the Selexol reboiler.

8) Temperature control of the fuel gas reheater.

9) Surge prevention of the booster compressor by control of the bypass of the compressor.

10) Instrumentation on the Claus unit and the waste water treatment are standard for those plants.

11.6.2 Power Block

11.6.2.1 PLANT INFORMATION AND DISPLAY SYSTEM

11.6.2.1.1 Purpose

The purpose of the plant information and display system will be to provide timely operator data for dynamic decision making and ready access to historical data for diagnostic analysis relative to plant availability, reliability and efficiency of operation. This system is proposed as a distributed network. Independent data collection which utilizes microprocessors for data acquisition will be employed for each combustion turbine and heat recovery boiler. The steam turbine will have an independent digital system as an integral portion of its control system which will provide information and display as well as startup and load control. In addition to the independent data collection, two overall plant display systems are proposed. The first would be a total plant data recording and display system. The second would be a plant calculation, operator guide and load supervisory control dispatch center.

11.6.2.2 SUPERVISORY CONTROL

11.6.2.2.1 Plant Supervisory

Plant-wide open loop operator guides for plant operation will be calculated. The results would be displayed to the plant engineering/operation personnel. Linear programming would be employed to parametrically determine the optimum mix of equipment and fuel mixture to satisfy the given conditions. Availability of equipment, load demand, present fuel availability and cost of fuels would be input parameters. Calculation would include consideration of load swing, capacity and speed governor response of steam and combustion turbines with parameters defined by plant engineering personnel. Combustion turbine efficiency and steam turbine efficiency would be evaluated. The calculations would involve projected steam flow split between coal gasifier waste heat boiler production and combustion turbine heat recovery steam generator production and the efficiency of each type of steam production. Interaction between gasifier and combustion turbine cycles would require iteration to solve the mathematical expression for the optimum operating points for the total plant including both steam and combustion turbines. Results would be displayed including number and choice of equipment to be placed in operation, coal usage rates, oil usage rates, combustion turbine fuel mix and projected efficiency for the given conditions. Neither direct digital nor supervisory control would directly use these results; but, the results would be available as operator guides.

11.6.2.2.2 Load Supervisory Control

A remote dispatch interface capability would be provided. This would include the capability for the operator to enter a total plant demand in lieu of a telemetered load demand signal. The Load Demand will be compared with total current generation. A supervisory control set point will be determined for each operating combustion turbine. The calculated setpoint will be compared with the current setpoint and raise-lower pulses will be generated at an appropriate ramp rate to each combustion turbine in order to move total generation to the desired demand.

11.6.2.2.3 Startup And Shutdown Operator Guides

Due to the complexity of proposed combined cycle, an Early Warning System will be developed particular to unit startup and shutdown. The system will provide the operator with dynamic guides in sequencing the total plant.

Included will be monitoring of:

- Combustion turbine condition prior to and during initiation of coal gasifier operation.
- Main steam header condition at the initiation of admittance of coal gasifier steam into the header.
- Condensate feedwater sequencing to the combustion turbine air cooler, the waste heat boiler, and the gasifier.
- Normal shutdown sequencing of the total plant.

No direct digital or setpoint supervisory control will be employed. Appropriate CRT displays will be generated for operator ready reference as a unit of the plant proceeds through its startup or normal stop transients.

11.6.2.3 RECORDING AND DISPLAY SYSTEM

The plant recording and display system will provide three basic features—one, data recording on magnetic tape of data for all unit startups and aborts; two, a CRT display for operator information; three, hardcopy output from the historical or current files for data as may be required.

A modular, distributed network approach will be utilized. Failure of any one component will not cause the loss of all data. Each combustion turbine and HRSG will have its own microprocessor and data collection input hardware. Each of these processors will contain its own printer. These printers may normally be turned off, but will be available as supplementary and/or backup devices to the central station magnetic tape, CRT, hardcopy output system. Dedicated microprocessors will not require any other information and display devices to be active for their proper operation, but will supply the analog and digital input front end for the central station recording and display system as well as the central station supervisory control processor. Likewise, the steam turbine control computer will front end the recording and display system as well as the supervisory control processor. ASCII interfaces will be provided with each front end processor device for communication to the other components of the total Information System.

11.6.2.3.1 Magnetic Tape System

Magnetic tape will be used as a long-term storage medium for data. These data will be available for display at the CRT for analysis or optionally for hardcopy output. File search routines will allow the operator of the system to selectively retrieve data via various keys such as: date, equipment identification (Combustion Turbine 1, or 2, or 3, or 4, etc.), startup data only, shutdown data only, vibration data, or temperature data.

Startup data recording will be initiated with initiation of the unit start sequence. For the combustion and steam turbines, data recording will terminate after turbine critical speeds have been exceeded.

Shutdown data will be taken from data dynamic buffers that will maintain a current history for each unit. Thus, data prior to and leading up to a shutdown, as well as data after the shutdown initiating event, will be recorded. Daily operation logs will also be written onto magnetic tape.

11.6.2.3.2 CRT Display

The CRT display will be a general-purpose unit for the total plant. This will be in addition to the CRT which is an integral portion of steam turbine control system.

The plant CRT will be used to:

- Display points currently in alarm with setpoint and current value of point in alarm.

- Trend variables as selected by the operator.

- Display startup and shutdown operator guide messages for the total plant.
- Display historical data from the magnetic tapes.
- Provide Sequence-of-Events display after a plant trip.
- Plant supervisory displays.
- Plant operating daily log.

Editing features will be available to add, delete, or change displays as may be required, such as entering operator comments into the daily log.

11.6.2.3.3 Hardcopy Output

A hardcopy output device will be provided which will have the capability of copying the current CRT display. In general, it will be the philosophy of the system to minimize the use of the hardcopy output unit. Excess output that is not of long-term interest, and which obscures the visibility of critical data will be avoided.

APPENDIX A
BTG CONSOLE DEVICE LIST

C-T — HRSG PANEL

Vertical Panel List

Device Number	Device Description	Type
1	Generator Kilovolts	Meter
2	Generator Amperes	Meter
3a	Synchroscope	Meter
3b	Synchroscope Lights	Light
4	Speed Indicator	Meter
5	Megawatts	Meter
6	Megavars	Meter
7a	Condensate Flow	Recorder Pen 1
7b	Deaerator Level	Recorder Pen 2
7c	Deaerator Pressure	Recorder Pen 3
8a	Feedwater Flow	Recorder Pen 1
8b	H. P. Drum Level	Recorder Pen 2
8c	Steam Flow	Recorder Pen 3
9a	Superheater Outlet Pressure	Recorder Pen 1
9b	Superheater Outlet Temperature	Recorder Pen 2
9c	Reheater Outlet Temperature	Recorder Pen 3
10a	Frequency	Indicator Pointer L
10b	Generator Null Meter	Indicator Pointer R
11a	Plant Voltage	Indicator Pointer L
11b	System Voltage	Indicator Pointer R
12a	Aux Bus Amps	Indicator Pointer L
12b	Aux Bus Volts	Indicator Pointer R
13a	Generator H_2 Pressure	Indicator Pointer L
13b	Generator H_2 Temperature	Indicator Pointer R
14a	Liquid Fuel Flow	Indicator Pointer L
14b	Gas Fuel Flow	Indicator Pointer R
15a	Blade Path Temperature	Indicator Pointer L
15b	Exhaust Temperature	Indicator Pointer R
16a	Spare	Indicator Pointer L
16b	Spare	Indicator Pointer R

Vertical Panel List (Continued)

Device Number	Device Description	Type
17a	Feedwater Pressure	Indicator Pointer L
17b	Economizer Recirculation Flow	Indicator Pointer R
18a	Air Cooler Flow	Indicator Pointer L
18b	Air Cooler Outlet Temperature	Indicator Pointer R
19a	Gas Fuel Heater Outlet Temperature	Indicator Pointer L
19b	Spare	Indicator Pointer R
20a	Spare	Indicator Pointer L
20b	H.P. Drum Conductivity	Indicator Pointer R
21a	WHB Economizer Inlet Flow	Indicator Pointer L
21b	WHB H.P. Drum Flow	Indicator Pointer R
22a	Spare	Indicator Pointer L
22b	Spare	Indicator Pointer R
23	Combustion Turbine Master Control On	Status Light
24	Combustion Turbine Turning Gear On	Status Light
25	Combustion Turbine Starting Device On	Status Light
26	Combustion Turbine Ignition On	Status Light
27	Combustion Turbine Fuel On	Status Light
28	Combustion Turbine Flame 14 On	Status Light
29	Combustion Turbine Flame 15 On	Status Light
30	Combustion Turbine Sync Speed	Status Light
31	Generator Breaker Closed	Status Light
32	Combustion Turbine Auto Unload	Status Light
33	Combustion Turbine Fast Shutdown	Status Light
34	Combustion Turbine Load Dump	Status Light
35	Combustion Turbine Aux Reset	Status Light
36	Combustion Turbine Trip Reset	Status Light
37	Combustion Turbine Ready-to-Start	Status Light
38	Voltage Regulator Auto	Pushbutton
39	Voltage Regulator Manual	Pushbutton
40	Synchronizer Auto	Pushbutton
41	Synchronizer Manual	Pushbutton
42	Field Breaker Close	Pushbutton
43	Field Breaker Trip	Pushbutton
44	Regulator Base Raise	Pushbutton
45	Regulator Base Lower	Pushbutton
46	Regulator Voltage Raise	Pushbutton
47	Regulator Voltage Lower	Pushbutton

Vertical Panel List (Continued)

Device Number	Device Description	Type
48	Speed/Load Raise	Pushbutton
49	Speed/Load Lower	Pushbutton
50	Generator Breaker Close	Pushbutton
51	Generator Breaker Trip	Pushbutton
52	Local Control Panel (CT)	Pushbutton
53	Remote Control Panel (CT)	Pushbutton
54	Attended Operation	Pushbutton
55	Unattended Operation	Pushbutton
56	Normal Start Load Rate	Pushbutton
57	Spin Start Device Hold	Pushbutton
58	Sync Speed Hold	Pushbutton
59	Stop Load	Pushbutton
60	Go	Pushbutton
61	Temperature Control Select	Pushbutton
62	Speed Control Select	Pushbutton
63	Megawatt Control Select	Pushbutton
64	Minimum Load Select	Pushbutton
65	Base Temperature Limit Select	Pushbutton
66	Peak Temperature Limit Select	Pushbutton
67	Auto Transfer Enable	Pushbutton
68	Auto Transfer Disable	Pushbutton
69	Gas Fuel	Pushbutton
70	Distillate Oil	Pushbutton
71	Trip Reset Select	Pushbutton
72	Start	Pushbutton
73	Normal Stop	Pushbutton
74	Trip	Pushbutton
75	Alarm Acknowledge	Pushbutton
76	First Out Reset	Pushbutton
77	Annunciator List	Pushbutton

Sloped Panel List

Device Number	Device Description	Type
1	Generator Volts Phase Select	Selector Switch
2	Generator Aux Phase Select	Selector Switch
3	Aux Bus Volts Phase Select	Selector Switch
4	Aux Bus Amps Phase Select	Selector Switch
5	HRSG Freed Protection Heater Switch	Selector Switch

Sloped Panel List (Continued)

Device Number	Device Description	Type
6	Fuel Ratio Setpoint Station	A/M Station
7	Inlet Guide Vane Position	A/M Station
8	Turbine Air Cooler Control	A/M Station
9	Deaerator Feed Control	A/M Station
10	Feedwater Valve Control	A/M Station
11	Economizer Recirc. Flow Control	A/M Station
12	Economizer Flow Control	A/M Station
13	Pegging Valve Control	A/M Station
14	Superheater Bypass Valve Control	A/M Station
15	Reheater Bypass Valve Control	A/M Station
16	Startup Bypass Valve Control	A/M Station
17	Blowdown Valve Control	A/M Station

STEAM TURBINE PANEL

Vertical Panel

Device Number	Device Description	Type
1	Generator Kilovolts	Meter
2	Generator Amperes	Meter
3	Synchroscope	Meter
4	Speed Indicator	Meter
5	Megawatts	Meter
6	Megavars	Meter
7	Synchronizing Lights	Light
8a	H.P. Throttle Chamber Pressure	Recorder Pen 1
8b	H.P. Impulse Chamber Pressure	Recorder Pen 2
8c	I.P. Inlet Pressure	Recorder Pen 3
9a	H.P. Throttle Temperature	Recorder Pen 1
9b	I.P. Inlet Temperature	Recorder Pen 2
9c	Condenser Vacuum	Recorder Pen 3
10a	H.P. Temperature Rate of Change	Recorder Pen 1
10b	I.P. Temperature Rate of Change	Recorder Pen 2
10c	Hotwell Level	Recorder Pen 3
11a	Frequency	Indicator Pointer L
11b	Generator Null Meter	Indicator Pointer R
12a	Plant Voltage	Indicator Pointer L
12b	System Voltage	Indicator Pointer R

Vertical Panel List (Continued)

Device Number	Device Description	Type
13a	Aux Bus Amps	Indicator Pointer L
13b	Aux Bus Volts	Indicator Pointer R
14a	Generator H_2 Pressure	Indicator Pointer L
14b	Generator H_2 Temperature	Indicator Pointer R
15a	H.P. Throttle Pressure	Indicator Pointer L
15b	H.P. Impulse Chamber Pressure	Indicator Pointer R
16a	I.P. Inlet Pressure	Indicator Pointer L
16b	H.P. Throttle Temperature	Indicator Pointer R
17a	I.P. Inlet Temperature	Indicator Pointer L
17b	Spare	Indicator Pointer R
18a	H.P. Temperature Rate of Change	Indicator Pointer L
18b	I.P. Temperature Rate of Change	Indicator Pointer R
19a	Extraction Pressure to DA	Indicator Pointer L
19b	Extraction Press to Gasifier	Indicator Pointer R
20a	Condenser Vacuum	Indicator Pointer L
20b	Hotwell Level	Indicator Pointer R
21a	Conductivity	Indicator Pointer L
21b	Condensate Pressure	Indicator Pointer R
22	S.T. Turning Gear On	Pushbutton
23	S.T. Turning Gear Off	Pushbutton
24	Closed Cooling Water Pump On	Pushbutton
25	Closed Cooling Water Pump Off	Pushbutton
26	Closed Cooling Water Pump Valve Open	Pushbutton
27	Closed Cooling Water Pump Valve Closed	Pushbutton
28	Circ. Water Pump On	Pushbutton
29	Circ. Water Pump Off	Pushbutton
30	Circ. Water Pump Valve Open	Pushbutton
31	Circ. Water Pump Valve Closed	Pushbutton
32	Extraction Valve #1 Open	Pushbutton
33	Extraction Valve #1 Closed	Pushbutton
34	Extraction Valve #2 Open	Pushbutton
35	Extraction Valve #2 Closed	Pushbutton
36	Extraction Valve #3 Open	Pushbutton
37	Extraction Valve #3 Closed	Pushbutton
38	Makeup Block Valve Open	Pushbutton
39	Makeup Block Valve Closed	Pushbutton
40	Makeup Pump On	Pushbutton
41	Makeup Pump Off	Pushbutton

Vertical Panel List (Continued)

Device Number	Device Description	Type
42	Condensate Pump #1 On	Pushbutton
43	Condensate Pump #1 Off	Pushbutton
44	Condensate Pump #2 On	Pushbutton
45	Condensate Pump #2 Off	Pushbutton
46	Condensate Pump #3 On	Pushbutton
47	Condensate Pump #3 Off	Pushbutton
48	Voltage Regulator Auto	Pushbutton
49	Voltage Regulator Manual	Pushbutton
50	Synchronizer Auto	Pushbutton
51	Synchronizer Manual	Pushbutton
52	Field Breaker Close	Pushbutton
53	Field Breaker Trip	Pushbutton
54	Regulator Base Raise	Pushbutton
55	Regulator Base Lower	Pushbutton
56	Regulator Voltage Raise	Pushbutton
57	Regulator Voltage Lower	Pushbutton
58	Generator Breaker Close	Pushbutton
59	Generator Breaker Trip	Pushbutton
60	Turbine Drains	Selector Switch
61	Exhaust Sprays	Selector Switch
62	Extraction Drains Set #1	Status Lights
63	Extraction Drains Set #2	Status Lights
64	Extraction Drains Set #3	Status Lights
65	Turbine Drains H. P.	Status Lights
66	Turbine Drains I. P.	Status Lights
67	Turbine Drains L. P.	Status Lights
68		
69	Alarm Acknowledge	Pushbutton
70	First Out Reset	Pushbutton
71	Annun. Test	Pushbutton

Sloped Panel

Device Number	Device Description	Type
1	Generator Volts Phase Select	Selector Switch
2	Generator Amps Phase Select	Selector Switch
3	Aux Bus Volts Phase Select	Selector Switch
4	Aux Bus Amps Phase Select	Selector Switch
5	H. P. Turbine Bypass Vlv Control	A/M Station
6	I. P. Turbine Bypass Vlv Control	A/M Station
7	Makeup Valve Control	A/M Station
8	Return Valve Control	A/M Station

DIGITAL ELECTRO-HYDRAULIC (DEH) PANEL

Vertical Panel

Device Number	Device Description	Type
1	CRT	- - -
2	Turbine Speed RPM	Digital Display
3	Generator Output MW	Digital Display
4	Reference	Digital Display
5	Reference Demand	Digital Display
6	Display	Digital Display
7	Display Demand	Digital Display
8	TV Additive Position	Indicator
9	GV Additive Position	Indicator
10	Digital Displays Control Push-button Set	Pushbutton
11	Valve Status	Pushbutton
12	TV	Pushbutton
13	Close	Pushbutton
14	Open	Pushbutton
15	GV	Pushbutton
16	Valve Test	Pushbutton
17	Valve Position Limit Display	Pushbutton
18	Valve Position Limit Lower	Pushbutton
19	Valve Position Limit Raise	Pushbutton
20	Single Valve/Sequence Valve	Pushbutton
21	Operator Auto (Select)	Pushbutton
22	ADS (Select)	Pushbutton
23	Auto Sync (Select)	Pushbutton
24	Plant Computer Control (Select)	Pushbutton
25	Auto Turbine Control	Pushbutton
26	Turbine Supervision Only	Pushbutton
27	Turbine Supervision Off	Pushbutton
28	Override Alarm	Pushbutton
29	Override Sensor Hold	Pushbutton
30	Return Sensor to Scan	Pushbutton
31	High Ld Rate/Norm Ld Rate	Pushbutton
32	Reference	Pushbutton
33	Hold	Pushbutton
34	Go	Pushbutton
35	Accel RPM/MIN	Pushbutton
36	Load Rate MW/MIN	Pushbutton
37	Low Limit	Pushbutton

Vertical Panel List (Continued)

Device Number	Device Description	Type
38	High Limit	Pushbutton
39	Transfer TV/GV	Pushbutton
40	Imp In/Imp Out	Pushbutton
41	MW In/MW Out	Pushbutton
42	Speed In/Speed Out	Pushbutton
43	TPC In/TPC Out	Pushbutton
44	TPC Set Point Display	Pushbutton
45	Auto Controller Reset	Pushbutton
46	Maint Test	Status Lights
47	Invalid Request	Status Lights
48	Point Out of Service	Status Lights
49	Turning Gear in Operation	Status Lights
50	Heat Soak in Progress	Status Lights
51	Speed in Sync Range	Status Lights
52	Turbine Decel/Turbine Accel	Status Lights
53	Speed Hold/Load Hold	Status Lights
54	Generator On Line	Status Lights
55	ATC Requests Turbine Trip	Status Lights
56	Turbine Tripped	Status Lights
57	Runback Oper.	Status Lights
58	CCI Monitor	Status Lights
59	Control Speed Channel Monitor	Status Lights
60	Control Speed Channel Out	Status Lights
61	OPC Speed Channel Monitor	Status Lights
62	OPC Press. Transd. Monitor	Status Lights
63	OPC Monitor	Status Lights
64	MW Transd. Monitor	Status Lights
65	Imp Press Transd. Monitor	Status Lights
66	Power Supply Monitor	Status Lights
67	Auto Controller Off	Status Lights
68	Throttle Press Transd. Monitor	Status Lights
69	Optimum Valve Position	Status Lights
70	Manual Not Tracking Auto	Status Lights

Sloped Panel

Device Number	Device Description	Type
1a	OPC Test	3 Position
1b	OPC In Service	Key Switch
1c	Overspeed Test Permissive	
2a	Maintenance Test	2 Position
2b	Off	Key Switch
3	Phone Jack	- - -

Sloped Panel List (Continued)

Device Number	Device Description	Type
4	Turbine Manual	Pushbutton
5	TV Lower	Pushbutton
6	TV Raise	Pushbutton
7	Fast Action	Pushbutton
8	GV Lower	Pushbutton
9	GV Raise	Pushbutton
10	CRT Control Pushbutton Set	Pushbuttons
11	Alarm Reset	Pushbutton
12	CRT Monitor and Reset	Pushbutton
13	Invalid Request	Pushbutton
14	Clear Messages	Pushbutton
15	Select Display Page	Pushbutton
16	Select Trend Frequency	Pushbutton
17	Digital Trend	Pushbutton
18	Analog Trend	Pushbutton
19	Select Trend Point	Pushbutton
20	Display Point	Pushbutton
21	Cancel	Pushbutton
22	Enter	Pushbutton
23	Left Side TV and GV Open/Close Set	Pushbutton/Status Light
24	Right Side TV and GV Open/Close Set	Pushbutton/Status Light
25	Left Side 1 RV and 1 IV Open/Close Set	Pushbutton/Status Light
26	Right Side 1 RV and 1 IV Open/Close Set	Pushbutton/Status Light
27	Left Side 2 RV and 2 IV Open/Close Set	Pushbutton/Status Light
28	Right Side 2 RV and 2 IV Open/Close Set	Pushbutton/Status Light
29	Left Side 3 RV and 3 IV Open/Close Set	Pushbutton/Status Light
30	Right Side 3 RV and 3 IV Open/Close Set	Pushbutton/Status Light
31	Latch	Pushbutton

PLANT AND AUXILIARY POWER PANEL

Auxiliary Power Vertical Panel

Device Number	Device Description	Type
1	Main Aux Power AC Amps	Meter (Circular Scale)
2	Main Aux Power AC Volts	Meter (Circular Scale)
3	Main Aux Power Megavars	Meter (Circular Scale)
4	Main Aux Power Megawatts	Meter (Circular Scale)
5	Reserve Aux Power AC Amps	Meter (Circular Scale)
6	Reserve Aux Power AC Volts	Meter (Circular Scale)
7	Reserve Aux Power Megavars	Meter (Circular Scale)
8	Reserve Aux Power Megawatts	Meter (Circular Scale)
9	Station AC Amps	Meter (Circular Scale)
10	Steam Turbine AC Amps	Meter (Circular Scale)
11	Comb. Turbine-HRSG 1 AC Amps	Meter (Circular Scale)
12	Comb. Turbine-HRSG 2 AC Amps	Meter (Circular Scale)
13	Comb. Turbine-HRSG 3 AC Amps	Meter (Circular Scale)
14	Comb. Turbine-HRSG 4 AC Amps	Meter (Circular Scale)

NOTE: This panel has ample space reserved for four (4) Trending Recorders and/or approximately 12-15 dual indicating meters (vertical scale type) for recording other durable plant variables.

Auxiliary Power Sloped Panel

Device Number	Device Description	Type
1	Main Auxiliary Power	Breaker Control Type Selector Switch
2	Reserve Auxiliary Power	Breaker Control Type Selector Switch
3	Auto/Manual Transfer	Selector Switch
4	Sync Check	Selector Switch
5	Station Circuit Breaker Control	Selector Switch
6	Steam Turbine Circuit Breaker Control	Selector Switch
7	CT-HRSG 1 Circuit Breaker Control	Selector Switch
8	CT-HRSG 2 Circuit Breaker Control	Selector Switch
9	CT-HRSG 3 Circuit Breaker Control	Selector Switch

Auxiliary Power Sloped Panel List (Continued)

Device Number	Device Description	Type
10	CT-HRSG 4 Circuit Breaker Control	Selector Switch
11	Main Aux Power Amp Meter Phase Selector	Thumbwheel Switch
12	Main Aux Power Volt Meter Phase Selector	Thumbwheel Switch
13	Reserve Aux Power Amp Meter Phase Selector	Thumbwheel Switch
14	Reserve Aux Power Volt Meter Phase Selector	Thumbwheel Switch
15	Station Amp Meter Phase Selector	Thumbwheel Switch
16	Steam Turbine Amp Meter Phase Selector	Thumbwheel Switch
17	CT-HRSG 1 Amp Meter Phase Selector	Thumbwheel Switch
18	CT-HRSG 2 Amp Meter Phase Selector	Thumbwheel Switch
19	CT-HRSG 3 Amp Meter Phase Selector	Thumbwheel Switch
20	CT-HRSG 4 Amp Meter Phase Selector	Thumbwheel Switch
21	Annunciator Test	Pushbutton
22	Alarm Acknowledge	Pushbutton
23	First Out Reset	Pushbutton

APPENDIX B
TYPICAL ALARM AND TRIP LIST

Combustion Turbine/HRSG Panel Annunciator List

No.	Alarm Description	Type
1	Turbine/Generator Vibration High	Alarm
2	Turbine/Generator Vibration Extra High	Trip
3	Rotor Cooling Air Temp High/Low	Alarm
4	Second-Stage Cooling Air Temp High/Low	Alarm
5	Instrument Air Pressure Low	Alarm
6	Control System Problem	Alarm
7	Control System Voltage High/Low	Alarm
8	Low Gas Pressure Auto Transfer to Oil	Alarm
9	Liquid Fuel Temperature Low	Alarm
10	Distillate Forward Pump Not Operating	Alarm
11	Lube Oil Pressure Low	Trip
12	Lube Oil Temperature High/Low	Alarm
13	Lube Level Low	Alarm
14	Lube Pump DC Voltage Low	Alarm
15	Lube System Trouble	Alarm
16	Generator Exciter Bearing Temperature High	Alarm
17	Turbine Enclosure Temperature High	Alarm
18	Battery Charger Trouble	Alarm
19	Power Supply Failure	Trip
20	Fuel Pump Low Suction/High Discharge Pressure	Trip
21	Ignition Oil Flow High	Trip
22	Fuel Filter Diff. Pressure High	Alarm
23	Fuel Distributor Failure	Alarm
24	Flame Detector Failure	Alarm
25	Turbine Flame Out	Trip
26	Blade Path Temperature Spread High	Alarm
27	Turbine Exhaust Temperature High	Alarm
28	Turbine Exhaust Temperature Extra High	Alarm
29	Turning Gear Not On	Alarm
30	Bleed Valves Not Open	Trip
31	Spin Sequence Check	Trip

Combustion Turbine/HRSG Panel Annunciator List (Continued)

No.	Alarm Description	Type
32	Starting Device Failure	Trip
33	Turbine Acceleration Low	Trip
34	Analog Controller Subsystem Failure	Trip
35	Bleed Valves Not Closed	Load Dump
36	Turbine Speed Low	Unload
37	Turbine Speed Extra Low	Trip
38	Turbine Overspeed	Trip
39	Combustion Turbine Compr. Inlet Press. Low	Alarm
40	Fire	Trip
41	Compressor Bleed to Process Failure	Alarm
42	Generator 86G Lockout Relay	Gast Stop
43	Generator 86-1 Lockout Relay	Breaker Opens
44	Transformer 86T Lockout Relay	Breaker Opens
45	Voltage Balance Relay	Alarm
46	Bus Underfrequency/Under Voltage	Alarm
47	Generator Underfrequency Under Voltage	Breaker Opens
48	Generator Hydrogen Trouble	Trip or Alarm
49	Voltage Regulator Trip	Alarm
50	Voltage Regulator Loss of Firing Circuit Pulse	Alarm
51	Voltage Regulator Over Excitation	Fast Stop
52	Voltage Regulator Volts per Hertz	Fast Stop
53	Voltage Regulator Ground/Brush Failure	Alarm
54	HRSG MCC Maint. Switch Wrong Position	Alarm
55	Exhaust Duct Pressure High	Alarm
56	Exhaust Duct Pressure Extra High	Trip
57	Stack Cover Not Open	Trip
58	HRSG Power Trouble	Alarm
59	Superheater Bypass Valve Wrong Position	Alarm
60	HRSG Startup Bypass Failure	Alarm
61	HRSG Transmitter Failure	Alarm
62	H_2 Vent Fan Trouble	Alarm
63	Chemical Feed System Failure	Alarm
64	Boiler Feed Pump Failure	Trip
65	Main BFP Delta P Low	Alarm
66	HP Feedwater Pressure Low	Alarm
67	HP Drum Level Low	Alarm
68	HP Drum Level High	Alarm
69	Main BFP Bypass Valve Wrong Position	Alarm

Comb. Turbine/HRSG Panel Annunciator List (Continued)

No.	Alarm Description	Type
70	D.A. Level Hi/Low	Alarm
71	Superheater Steam Pressure High	Trip
72	Superheater Steam Temperature High Runback	Alarm Load Runback
73	Standby BFP Delta P Low	Alarm
74	HP Circ. Pump Seal Temp. High	Alarm
75	HP Circ. Pump Delta P Low	Trip
76	HP Circ. Pump Trouble	Alarm
77	LP Circ. Pump Delta P Low	Alarm
78	Main BFP Trouble	Alarm
79	Reheater Bypass Valve Wrong Position	Alarm
80	Reheater Steam Pressure High	Alarm
81	Reheater Steam Temperature High Runback	Alarm
82	Analog Controller Subsystem Trouble	Alarm

Steam Turbine Panel Annunciator List

No.	Alarm Description	Type
1	Steam Turbine Trip	Trip
2	Thrust Bearing Trip	Trip
3	Vibration Trip	Trip
4	Vibration High	Alarm
5	Eccentricity High	Alarm
6	Thrust Bearing	Alarm
7	Bearing Temperature High	Alarm
8	Rotor Position	Alarm
9	Differential Expansion High	Alarm
10	DEH Fluid Pressure Low Trip	Trip
11	DEH Fluid Level Low Lockout	Alarm
12	DEH Fluid Pressure Low	Alarm
13	DEH Fluid Pressure High	Alarm
14	DEH Fluid Level Low	Alarm
15	DEH Fluid Level High	Alarm
16	DEH Fluid Return Pressure High	Alarm
17	DEH Fluid PU 1 Filter Pressure Drop High	Alarm
18	DEH Fluid PU 2 Filter Pressure Drop High	Alarm
19	Fire	Trip
20	TPC Operating	Alarm
21	Steam Turbine Control Power Failure	Alarm

Steam Turbine Panel Annunciator List (Continued)

No.	Alarm Description	Type
22	DEH Backup Pump Running	Alarm
23	DEH Transducer Failure	Alarm
24	DEH Fluid Temperature High	Alarm
25	DEH Reject to Manual	Alarm
26	DEH System Alarm Message	Alarm
27	Overspeed Trip	Trip
28	Lube Oil Pressure Low Trip	Trip
29	OPC Operating	Alarm
30	Lube Oil Pressure Low	Alarm
31	Main Lube Oil Pump Off	Alarm
32	Lube Oil Level Low	Alarm
33	Lube Oil Temperature High/Low	Alarm
34	DC Lube Pump Power Loss	Alarm
35	Speed Transducer Failure	Alarm
36	Generator 86G Lockout Relay	Fast Stop
37	Generator 86-1 Lockout Relay	Breaker Opens
38	Transformer 86T Lockout Relay	Breaker Opens
39	Voltage Balance Relay	Alarm
40	Bus Under Frequency Under Voltage	Alarm
41	Generator Under Frequency Under Voltage	Breaker Opens
42	Generator Hydrogen Trouble	Trip or Alarm
43	Voltage Regulator Trip	Alarm
44	Voltage Regulator Loss of Firing Circuit Pulse	Alarm
45	Voltage Regulator Over Excitation	Fast Stop
46	Voltage Regulator Volts per Hertz	Fast Stop
47	Voltage Regulator Ground/Brush Failure	Alarm
48	Gland Steam Pressure High/Low	Alarm
49	Gland Steam Temperature High/Low	Alarm
50	Gland Condenser Pressure High	Alarm
51	Turbine Motoring Trip	Trip
52	Vacuum Low Trip	Trip
53	ST PS and GC Maintenance Switch Wrong Position	Alarm
54	Vacuum Low	Alarm
55	Latch Not Reset	Alarm
56	Vacuum Trip Locked Out	Alarm
57	HP Steam Temperature Rate of Change High	Alarm
58	Blanket/Casing Temperature High	Alarm
59	Instrument Air Pressure Low	Alarm
60	ST Bypass Valve Tripped	Alarm
61	Condensate Bypass Valve Wrong Position	Alarm

Steam Turbine Panel Annunciator List (Continued)

No.	Alarm Description	Type
62	ST Turbine Extraction Failure	Alarm
63	Main Steam Desuperheater Outlet Temperature High	Alarm
64	Reheat Steam Desuperheater Outlet Temperature High	Alarm
65	Reheat Bypass Valve Failure	Alarm
66	I. P. Steam Temperature Rate of Change High	Alarm
67	Exhaust Temperature 250°F	Alarm
68	ST Enclosure Temperature High	Alarm
69	Condenser Trip	Trip
70	Condenser Unavailable	Trip
71	Condensate Pressure Low	Alarm
72	Hotwell Level High	Alarm
73	Hotwell Level Low	Alarm
74	Hotwell Transducer Failure	Alarm
75	Condensate Pump 1 Delta P Failure	Alarm
76	Condensate Pump 2 Delta P Failure	Alarm
77	Condensate Pump 3 Delta P Failure	Alarm
78	ATC Message	Alarm
79	ST MCC Maint. Switch Wrong Position	Alarm
80	Hotwell Control Power Failure	Alarm
81	Gland Steam Condenser Level High	Alarm
82	Extraction Drain Level High	Alarm
83	Gland Steam Pressure Low	Alarm
84	Air Ejector Steam Pressure Low	Alarm

Plant and Auxiliary Power Panel Annunciator List

No.	Alarm Description	Type
1	Information Computer Failure	Alarm
2	Computer DC Failure	Alarm
3	26 VDC BTG Power Failure	Alarm
4	Control Room Fire	Alarm
5	Air Compressor Skid Fire	Alarm
6	Air Compressor Skid Trouble	Alarm
7	Control Room Conditioner Failure	Alarm
8	Control Room Air Circ. Fan Failure	Alarm
9	1 Charger Failure	Alarm
10	2 Charger Failure	Alarm

Plant and Auxiliary Power Panel Annunciator List (Continued)

No.	Alarm Description	Type
11	ST Charger Failure	Alarm
12	3 Charger Failure	Alarm
13	4 Charger Failure	Alarm
14	Main Plant Battery Reserve	Alarm
15	Closed Cooling Water System Pump Failure	Alarm
16	Closed Cooling Water Temperature High	Alarm
17	Closed Cooling Water Head Tank High/Low	Alarm
18	Circulating Water Pump 1 Fail	Alarm
19	Circulating Water Pump 2 Fail	Alarm
20	Demineralizer Trouble	Alarm
21	Makeup Storage Level High/Low	Alarm
22	Makeup Trouble	Alarm
23	Oil Fuel Tank Level High/Low	Alarm
24	Backup Fuel Forwarding Pump Running	Alarm
25	Auxiliary Power Main Breaker Trip	Alarm
26	Auxiliary Power Feeder Trip	Alarm
27	Main Auxiliary Transformer Differential	Alarm
28	Main Auxiliary Transformer Trouble	Alarm
29	Alternate Auxiliary Transformer Differential	Alarm
30	Alternate Auxiliary Transformer Trouble	Alarm
31	CT 1 Generator Breaker 52-1 Low Pressure	Alarm
32	CT 1 Transformer Differential	Alarm
33	CT 1 Transformer Trouble	Alarm
34	CT 1 Bus Breaker 52-5 Trip	Alarm
35	CT 1 Bus Breaker 52-5 Low Pressure	Alarm
36	CT 2 Generator Breaker 52-2 Low Pressure	Alarm
37	CT 2 Transformer Differential	Alarm
38	CT 2 Transformer Trouble	Alarm
39	CT 2 Bus Breaker 52-6 Trip	Alarm
40	CT 2 Bus Breaker 52-6 Low Pressure	Alarm
41	CT 3 Generator Breaker 52-3 Low Pressure	Alarm
42	CT 3 Transformer Differential	Alarm
43	CT 3 Transformer Trouble	Alarm
44	CT 3 Bus Breaker 52-7 Trip	Alarm
45	CT 3 Bus Breaker 52-7 Low Pressure	Alarm
46	CT 4 Generator Breaker 52-4 Low Pressure	Alarm
47	CT 4 Transformer Differential	Alarm
48	CT 4 Transformer Trouble	Alarm
49	CT 4 Bus Breaker 52-8 Trip	Alarm
50	CT 4 Bus Breaker 52-8 Low Pressure	Alarm

Plant and Auxiliary Power Panel Annunciator List (Continued)

No.	Alarm Description	Type
51	ST Bus Breaker 52-ST Low Pressure	Alarm
52	ST Transformer Differential	Alarm
53	Steam Turbine Transformer Trouble	Alarm
54	Bus Differential 86B Trip	Alarm

REFERENCES

Reference
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1. "A Report On Improving the Productivity of Electric Power Plants," prepared by FEA Inter-Agency Task Group On Power Plant Reliability, March, 1975.

2. Contract No. EX-76-C-01-2290, Topical Report No. FE-2290-18, Overall Plant Description — Low-Btu Combined Cycle Electric Power Plant.