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OVERALL PLANT DESIGN DESCRIPTION (OPDD)
LOW-BTU CO GAS
ELECTRIC POWER PLANT

TOPICAL REPORT

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TABLE OF CONTENTS

TABLE OF CONTENTS (CONT'D)

Section Page

4 PLANT DESIGN CRITERIA AND GUIDELINES (Cont'd)

TABLE OF CONTENTS (CONT'D)

TABLE OF CONTENTS (CONT'D)

LIST OF ILLUSTRATIONS

LIST OF ILLUSTRATIONS (CONT'D)

LIST OF TABLES

LIST OF TABLES (CONT'D)

Section 1

INTRODUCTION

1.1 PROGRAM AND TASK DESCRIPTIONS

1.1.1 Program Description

The objective of the ERDA-HTTT Program is to bring to Technology Readiness within six years a high-temperature turbine for use in a combined cycle using coal-derived fuel at a firing temperature of 2600 °F with growth capability to 3000 °F. The program is to be conducted in three phases:

- Phase I - Program and System Definition
- Phase II - Technology Testing and Test Support Studies
- Phase III - Technology Readiness Verification Test Program

The scope of the work for the entire program will encompass the design, development, manufacture, and test of a full-size turbine subsystem adapted to a General Electric MS-7001 gas turbine to be tested in a National Low-Btu Gasification Test Facility or, alternatively, in the General Electric load test facility in Greenville, South Carolina.

This Overall Plant Design Description (OPDD) for the integrated low-Btu Coal Gasification System - Combined Cycle system (CGS-CC) has been prepared as part of Phase I, Program and System Definition, in accordance with the following Statement of Work as proposed for the High-Temperature Turbine Technology Program.

1.1.2 Task 1 -- Prepare OPDD for (1) Coal Gas Combined Cycle Plant and (2) Coal Liquid Combined Cycle Plant

The contractor shall establish an Overall Plant Design Description (OPDD) for one gasification combined cycle powerplant and one coal-derived liquid fuel combined cycle plant, as outlined below.

The OPDD provides an overview and orientation of the various systems, structures, and facilities which comprise the plant, with an identification of the individual systems, their boundaries and interfaces, and the SDDs (System Design Descriptions as used by ERDA for design control and project management) that must be prepared to cover them. The OPDD should not include the extensive detail expected in the individual SDDs, but should provide concise descriptions of the overall functions, interfaces, and layout of plant systems, structures, and facilities.

The OPDD does not contain any technical information beyond that appearing in more detail in the specified individual SDDs, except for that information covering those plant services and facilities which are not otherwise to be covered by SDDs.

Content. The OPDD presents a concise summary of the design and principal parameters of the overall plant, a definition of individual systems, facilities, and services comprising the plant, the corresponding SDD assignment, and a brief description of ancillary services, facilities, and systems not otherwise covered by SDDs. Although no particular format is prescribed for the OPDD, the following information shall be included and organized as a minimum for effective presentation, considering the complexity of the particular plant design:

1. Brief description of the overall plant complex, including the site, gasifier (for the low-Btu plants) and support equipment, general support facilities, and the location and arrangement of principal gas turbine and steam cycle components and systems

2. Principal design guidelines, criteria, and overall plant requirements

3. Principal plant operating and design parameters

4. Overall plant cycle diagram and heat balance

5. Listing of all systems, services, and facilities comprising the plant and the identification of corresponding SDDs as well as those areas for which no SDDs are required

6. Descriptive paragraphs for each system and facility, concisely indicating its functions, principal requirements, and parameters; its boundaries and principal interfaces with other related systems and facilities, including simplified schematic diagrams where appropriate, are to be included for clarity or to reduce extensive narrative.

7. Brief description of overall plant operating modes, including identification of principal control station locations (This section is not intended to be the location for overall plant operating procedure outlines, which should be included elsewhere in the SDDs. However, it should denote specifically in which SDDs these procedure outlines are located.)

8. Brief description of plant maintenance requirements and capabilities, as well as the systems and facilities provided for maintenance

9. Appropriate diagrams and drawings, including:

   a) Site plan

   b) Composite (gasification) plant system diagram, including cleanup systems

c) Combustion turbine cycle diagram

d) Steam cycle diagram

e) Electrical power distribution diagram

f) Selected overall layout and arrangement drawings which show the orientation of principal plant components, systems, and facilities

10. Preparation of the plant layouts are to follow the Middletown, USA site conditions similar to those used in the ECAS Studies.

11. The heat balance is to be calculated on the basis of sea level and 59 °F, using fuel higher heating values. The steam turbine condenser will be operating at 2.5 Hg Abs., with circulating water cooled by wet mechanical draft cooling towers. The contractor is to provide, in the final report, performance data of their most efficient liquid-fueled gas turbine combined cycle powerplant, in operation or under construction. This data is to be used in sufficient detail to make a direct comparison with the performance of the plants covered by this contract.

12. The contractor will determine plant startup times under various conditions of readiness (cold, warm, hot, etc.).

In establishing the OPDD for the gasification combined cycle plant, evaluations will be made of fixed-bed and entrained-bed gasification plants. The OPDD for the gasification combined cycle powerplant will be generated using the type of gasification plant selected as a result of the evaluations. The gasification plants to be evaluated will utilize low-temperature gas cleanup systems and will have firing temperatures of 2600 °F.

The OPDDs will not include the coal liquefaction plant or the liquid fuel cleanup system. Performance levels for the cleanup system, the steam turbine, and the heat recovery steam generator will be based on commercially available equipment. Performance levels for the other equipment will be estimated.

1.1.2.1 Preliminary System Definition. The two OPDDs will be based on the cycle shown in Table 1-1 for either case A or B and case C. The firing temperature will be 2600 °F for all cases.

Table 1-1

PLANT PRELIMINARY DEFINITIONS FOR OPDD

Case A.	Fixed Bed	
	Gas Cleanup system	Low Temperature
	Steam conditions	2400 psig 1000 °F/1000 °F, 2-1/2 in. HgAbs
	Pressure ratio	16
Case B.	Entrained Bed	
	Gas cleanup system	Low Temperature
	Steam conditions	2400 psig, 1000 °F/1000 °F, 2-1/2 in. HgAbs
	Pressure ratio	16
Case C.	Coal-Derived Liquid Fuel	
	Steam conditions	2400 psig, 1000 °F/1000 °F, 2-1/2 in. HgAbs
	Pressure ratio	16

System studies and cycle analyses will be conducted for each case, shown in Table 1-1, in order to provide a basis for selecting the cycle arrangement to be used in the OPDD. A preliminary system definition will be made for the cycle arrangement selected for each case. The preliminary system definition will consist of a definition of the overall plant performance and a system schematic of the flow sheet showing the overall system arrangement of the gas turbine, the steam turbine, the gasifier, and, where applicable, the gas cleanup system. The primary cycles and arrangements shall be configured for baseload utility service, but consideration will be given to providing capability for midrange and peaking duties. In addition, a preliminary system definition will be made on the other plant arrangements and cycle configurations shown in Table 1-2. A performance comparison will also be provided comparing the performance results in Table 1-1 with the contractor's standard commercial liquid petroleum fuel combined cycle plant.

Table 1-2

ADDITIONAL PLANT PRELIMINARY SYSTEM DEFINITIONS

Case A. Fixed Bed

	BASE DESIGN								BACKUP DESIGN			
Firing Temperature	2600 °F				3000 °F				2600 °F		3000 °F	
Gas cleanup system	Low Temp.			Int. Temp.	Low Temp.			Int. Temp.	Low Temp.	Int. Temp.	Low Temp.	Int. Temp.
Steam conditions	2100 psig, 1000 °F/1000 °F, 2-1/2 in. HgAbs 1800 psig, 1000 °F/1000 °F, 2-1/2 in. HgAbs											
Pressure ratio	12	16	20	16	12	16	20	16	16	16	16	16
System definition and performance	X	X	X	X		X	X	X	X	X	X	X
Gas turbine cost		X				X			X			
Plant cost		X										

Case B. Entrained Bed

	BASE DESIGN				BACKUP DESIGN			
Firing Temperature	2600 °F		3000 °F		2600 °F		3000 °F	
Gas cleanup system	Low Temp.	High Temp.	Low Temp.	High Temp.	Low Temp.	High Temp.	Low Temp.	High Temp.
Steam conditions	2400 psig, 1000 °F/1000 °F, 2-1/2 in. HgAbs							
Pressure ratio	16							
System definition and performance	X	X	X	X	X	X	X	X
Gas turbine cost	X		X					
Plant cost	X							

Case C. Coal-Derived Liquid Fuel

	BASE DESIGN				BACKUP DESIGN			
Firing Temperature	2600 °F		3000 °F		2600 °F		3000 °F	
Steam conditions	2400 psig. 1000 °F/1000 °F, 2-1/2 in. HgAbs							
Pressure ratio	16							
System definition and performance	X		X		X		X	
Gas turbine cost	X		X		X			
Plant cost	X							

1.1.2.2 Gas Cleanup System Appraisal. Candidate gas cleanup systems, low- and intermediate-temperature, will be appraised for use in Case A and low- and high-temperature for use in Case B. Consideration will be given to system selectivity, control requirements, operational characteristics, including service requirements and effects on overall plant performance and test. Based on these studies, low-temperature cleanup systems will be selected for further use in the OPDDs, and feasibility of hot gas cleanup will be assessed for possible further investigative work in Phase II of this program, or elsewhere.

1.1.2.3 Functional Specifications. Specifications will be developed setting out functional requirements for the gas turbine, the steam turbine, the Heat Recovery Steam Generator (HRSG), gasifier and cleanup system, (for Cases A and B) and the balance-of-plant equipment.

1.1.2.4 System Control Requirements. A general description of the control requirements will be made for the following components and systems of the overall power plant: the gas turbine, the heat recovery steam generator, the steam turbine, the combined cycle plant, the gasifier, the gas cleanup system, and the boost compressor.

1.1.2.5 Integrated Overall Plant Operating Mode. General descriptions will be made of the following modes of operation for the overall plant: standby, startup, normal load following, and contingency and failure.

1.2 TOPICAL REPORT DESCRIPTION

This Overall Power Plant Design description (OPDD) for the integrated, low-Btu fixed-bed Coal Gasification System-Combined Cycle (CGS-CC) plant is intended to establish the functional specifications and control requirements for General Electric Company's advanced water-cooled gas turbine operating at 2600 °F and for the other major components and subsystems associated with the baseline combined cycle design.

One of the major criteria of the Energy Research and Development Administration (ERDA) leading to the overall system definition is that technological readiness be demonstrated within six years of the June 1, 1976, contract startup date. An efficiency that is as high as is economically feasible is, of course, a major objective. Another major ERDA criterion was that the potential of high-temperature gas cleanup be investigated from the standpoints of technical and practical availability and effect on overall plant performance.

To implement an integrated baseline combined cycle that has a good potential for technological readiness within six years, General Electric Company selected the fixed-bed gasification system as one of two systems for evaluation. The second is Foster Wheeler Energy Corporation's low-Btu entrained-bed gasification system, which operates with a relatively high off-gas temperature of about 1700 °F and permits the full potential of high-temperature cleanup to be considered.

The performance and overall characteristics of General Electric Company's advanced fixed-bed gasifier are assumed, thereby permitting a direct comparison with the results obtained by the General Electric Company in the ECAS program.*

Five basic subtasks have been carried out in the development of the OPDD. In the first subtask, Preliminary System Definition, various overall plant arrangements were investigated initially on the basis of using low-temperature cleanup, with preliminary efficiency levels for the major components and the reference water-cooled gas turbine. The data from these initial system studies was used to initiate the appraisal of low-temperature, low-Btu gas cleanup systems as part of Subtask 2, Cleanup System Definition. The data was also used to initiate development work in the areas of the gas turbine subsystem and gas turbine systems (such as inlet and exhaust treatment, generator, etc.).

Three low-temperature gas cleanup systems have been evaluated: the Alkazid system; the Benfield hot potassium carbonate system; and the Selexol system. The total energy costs for the respective CGS-CC systems were developed, including installed costs, chemical

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*Contract No. NAS 3-19406

costs, efficiency, service requirements, and experience. As a result of these studies the Benfield and Alkazid cleanup systems were selected for use with the advanced fixed-bed and entrained-bed gasification systems, respectively.

Concurrent with the Subtask 2 effort to select a preferred low-temperature gas cleanup system, overall plant parametric studies with respect to gas turbine pressure ratio and steam conditions were carried out, utilizing updated performance data for the gas turbine, other major components, and the gas cleanup system. Consequently, the overall system definition at the time of selecting a preferred cleanup system was the basis of many of the functional specifications for the major plant components and subsystems that were developed and issued as part of Subtask 3. These studies led to the verification of a 16:1 compressor pressure ratio and steam conditions of 2400 psig/1000 °F/1000 °F/2.5" HgAbs.

Another major effort in the concurrent preliminary system work was the study of alternative gas turbine cooling systems, wherein the water-cooled concept was verified as the preferred (reference) design concept, and a backup design which utilizes water-cooled nozzles and steam-cooled buckets was identified.

In Subtask 4, Major Plant Component Operating Characteristics, the operating characteristics of the major plant components and subsystems have been considered as a basis for executing Subtask 5, Integrated Plant Operating Modes. To the greatest extent possible, the automated features of General Electric Company's STAG plants have been retained.

Research in the area of intermediate- and high-temperature cleanup, carried out in conjunction with C.F. Braun and Co. and General Electric Company's Corporate Research and Development Center, confirmed the selection of low-temperature gas cleanup for a plant wherein the objective is technology readiness in six years. Among the systems that have been considered, the iron oxide system is considered to have the potential for commercial development and offers an attractive improvement in overall plant performance. The General Electric Company has proposed an optional program for Phase II, wherein the potential of this intermediate temperature cleanup system would be investigated on an actual laboratory basis, taking advantage of the General Electric Company Research and Development Center's advanced fixed-bed gasifier pilot plant.

The selection of the advanced fixed-bed gasification system, in addition to reflecting its recognized edge in experience, has been based on a consideration of the relative performance and operational characteristics. The specific relative rankings of the two gasification systems in ten areas which were considered are detailed and presented in a following section of this report. It should be emphasized that the fixed-bed system has been selected to provide a basis for proceeding into and through the following Phase II and in no way implies any advocacy on the part of General Electric Company's Gas Turbine Division.

NOTE: FIRING TEMPERATURE IS DEFINED BY GE AS THE AVERAGE TOTAL TEMPERATURE AT THE ENTRANCE TO THE FIRST STAGE BUCKETS AFTER ALL NOZZLE COOLING FLOWS AND SEAL LEAKAGES HAVE BEEN MIXED WITH THE COMBUSTOR DISCHARGE FLOW.

Section 2

SUMMARY - DESCRIPTION OF THE OVERALL PLANT COMPLEX

This section provides a brief description of the overall plant which incorporates the Fixed-bed - Coal Gasification System - Combined Cycle (FB-CGS-CC) to provide a net power output of 504 megawatts with a thermal efficiency of 41.42 percent, based on a higher heating value coal pile to bus-bar. The site plan for the plant is shown on Figure 2-1. More detailed descriptive information on the FB-CGS-CC is presented later in this report and in the Reference Design. It should be noted that the Entrained-Bed - Coal Gasification - Combined Cycle (EB-CGS-CC) has been studied as an alternative plant in parallel with FB-CGS-CC. Study results of EB-CGS-CC are reported in this document and in the Appendix of the Reference Design. Major systems for both FB and EB coal gas plants include the following categories: fuel system, prime cycle, bottoming cycle, balance of plant, integrated plant control, and electrical. Each of these major system categories is described below.

The fuel system accepts run-of-mine coal delivered by 100-car-unit trains every other day, unloads,weighs, and stores coal in an active pile (8-day supply) and a dead storage pile (30-day supply). Coal from the active pile is handled through crushing, screening, and conveying equipment in two streams: a one-quarter-flow fine stream, which is dried from 13 to 3 percent moisture, and a three-quarter-flow stream, which is not dried. The two coal streams are fed to bunkers located in the fixed-bed gasifier house. Low-btu coal gas is generated from the coal in a bank of 14 gasifiers and fed through a low-temperature gas cleanup system. Ash and other wastes are rejected from the gasifier house. The gas cleanup system removes sulfur and other undesirable constituents from the gas before it is supplied to the combustors in the gas turbines.

The prime cycle system accepts the low-Btu gas and burns it in two gas turbine-generators, each rated at 180 MW output. The gas turbines are water-cooled to permit a firing temperature of 2600 $^{\circ}$F with minimum corrosion and deposition problems. Extraction air from the gas turbine compressor provides air blast to the gasifiers. Boost compressors driven by steam turbine drivers increase the pressure of the air blast. Exhaust gas from the gas turbine passes into a Heat Recovery Steam Generator (HRSG), where steam is produced for the bottoming cycle.

The bottoming cycle system includes the two HRSGs, the single 155 MW steam-turbine generator, the condenser, and all steam cycle associated equipment and subsystems such as the steam bypass, deaerator, boiler feed pumps, etc.

The balance-of-plant system includes the water supply and preparation equipment, heat rejection equipment including cooling towers and stacks, other mechanical and electrical support systems, and remaining plant services.

The integrated plant control includes a central control room, which houses control of all plant functions including coal supply, gasification, and prime cycle and bottoming cycle operation to meet electrical load demand and operate within environmental standards.

The electrical power system includes equipment provided for internal plant electrical power supply to the major plant systems and equipment required to connect gas and steam turbine generators to the output electrical power high line.

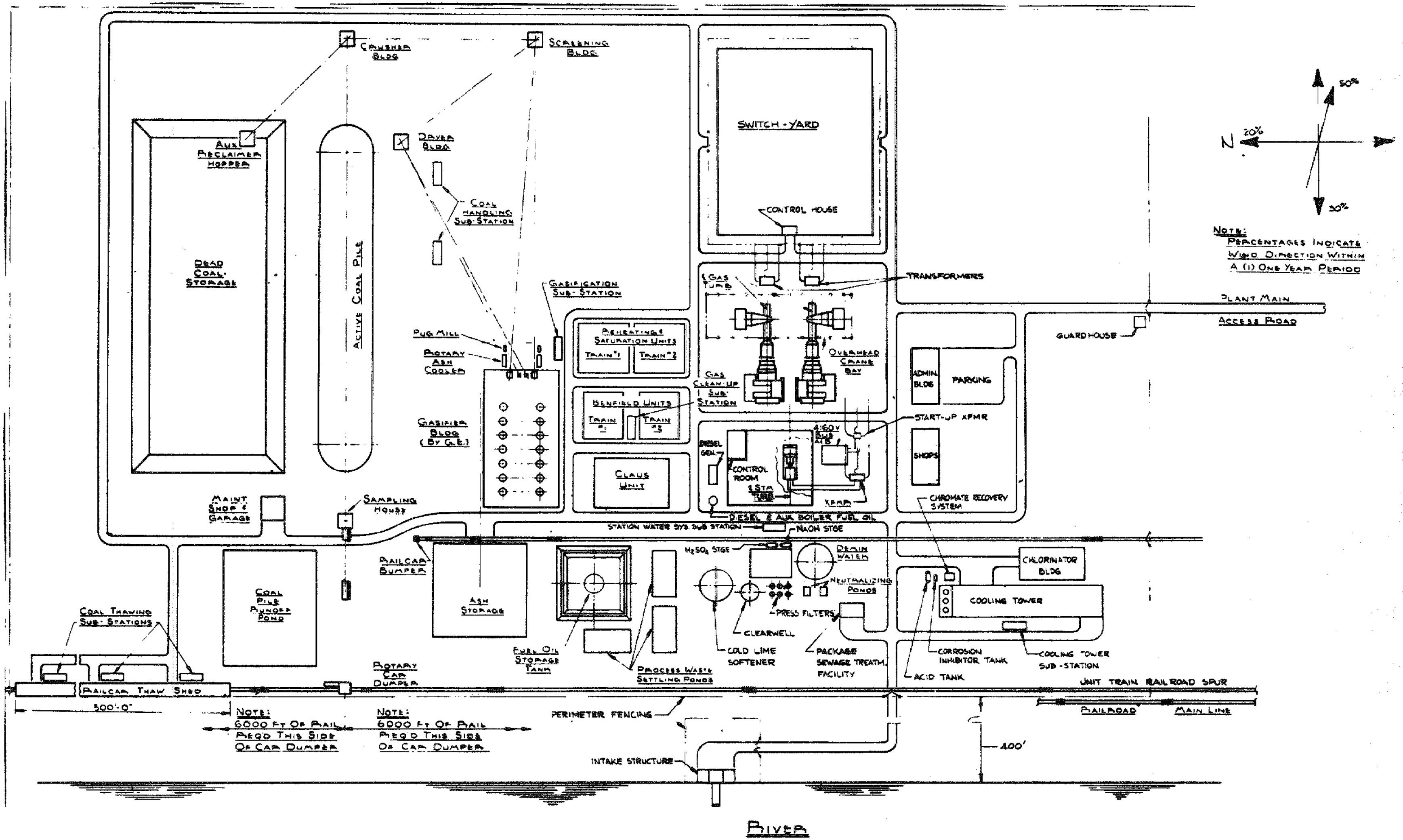

Figure 2-1. Overall Site Plan for the Fixed-Bed Coal Gasification Combined Cycle Power Plant

Section 3

OVERALL CYCLE DEFINITION, HEAT BALANCE, AND OPERATING AND DESIGN PARAMETERS

3.1 INTRODUCTION

An integrated Coal Gasification System-Combined Cycle (CGS-CC) has been developed to assist in establishing the functional specifications required for designing a high-temperature gas turbine utilizing low-Btu gas fuel. Improvement in overall plant efficiency and the attainment of technology readiness within six years have been the basic criteria for selecting the gasification system and establishing gas turbine pressure ratio, steam conditions, and the combined cycle configuration. Studies have resulted in the selection of the advanced fixed-bed gasification system with a Benfield cleanup system, a gas turbine compressor pressure ratio of 16 to 1, and steam conditions of 2400 psig/ 1000 ^{o}F/1000 ^{o}F/2.5" HgAbs. In this baseline CGS-CC system at 2600 ^{o}F, a water-cooled gas turbine, which offers the most attractive overall plant efficiency, was selected as the reference design after comparative studies of gas turbines with alternative cooling schemes, including all-steam, all-air, and combined water-steam systems. The overall plant efficiency is 41.42% on a coal pile to bus-bar basis.

Although relatively small changes in this efficiency are to be expected as the designs for specific components and subsystems mature, it is General Electric Company's opinion that major improvements resulting from the use of high-temperature gas cleanup and/or advanced gasification systems can only be realized well after the time required for demonstrating technology readiness. However, these improvements are potentially attractive. For example, if high-temperature gas cleanup is used with fixed-bed gasification technology, the overall net plant efficiency can be about 42.8%. If an advanced entrained-bed system is used with low-temperature gas cleanup, an overall efficiency of about 42.2% can be attained; this can improve to 42.8% with very-high-temperature cleanup.

Details of the definition, analysis, operation, and specifications for CGS-CC systems with both fixed-bed and entrained bed gasification systems will be presented in this report.

Fortuitously, the low metal temperatures inherent in the water-cooled type of design result in excellent fuel flexibility, which is uniquely suitable for applications with coal-derived liquid fuels; this is another factor in the selection of water-cooled technology for the reference gas turbine.

3.2 COMBINED CYCLE CONFIGURATION

The basic thermodynamic configuration that is used for the integrated CGS-CC plant with the fixed-bed gasification system is one wherein all of the fuel to the power systems is burned in the gas turbine combustors, and each gas turbine is arranged with its own unfired HRSG to generate high-pressure throttle steam and to reheat steam at a lower pressure for use in the steam turbine's reheat section. Since all of the fuel to the power system is burned in the gas turbine combustors, the plant is characterized by a high ratio of gas-to-steam turbine power. Relatively low cost per installed kilowatt is realized because of the relatively low cost of gas turbine power.

It should be noted that this basic configuration, utilizing 1900 to 2000 °F* gas turbines that are commercially available at this time and firing No. 2 distillate and/or natural gas, is widely accepted by the utility industry as a source of low-cost electrical energy with an overall plant efficiency that is significantly better than large reheat steam plants which burn either oil or coal. At this current commercial level of firing temperature, 1900 to 2000 °F,* more exotic system arrangements, although offering attractive improvements in overall plant efficiency, have not proven economically and/or operationally attractive to the power industry; such exotic arrangements include the supercharged boiler concept, the exhaust-fired boiler concept, and dual-pressure boilers.

For the HTTT program the continued use of the unfired, atmospheric HRSG is supported by additional factors. With the gas turbine design parameters of 16 to 1 pressure ratio and 2600 °F,* supplementary firing is not a viable option because of the low level of oxygen in the gas turbine exhaust. The use of a dual pressure boiler, wherein the low pressure loop generates steam to be reheated for use in the steam turbine, results in only a marginal improvement in overall plant efficiency of about 0.13 points, or 0.25%, while introducing extra costs and an impairment of operating flexibility. The supercharged boiler, while introducing a significant improvement in overall plant efficiency, must be considered developmental, based on the program's technology readiness schedule.

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*Firing Temperature

3.3 THE INTEGRATED, FIXED-BED LOW-BTU COAL GASIFICATION SYSTEM--COMBINED CYCLE SYSTEM (CGS-CC)

3.3.1 Cycle Configuration

The system schematic for the integrated low-Btu CGS-CC system with the advanced fixed-bed gasification system and using the reference water-cooled gas turbine design concept is shown on Figure 3-1. The net overall plant heat rate is 8240 Btu/kW-hr, 41.42% (HHV), on a coal pile to bus-bar basis and with auxiliary power requirements as delineated in Table 3-1. In this plant the gas turbine, operating at 16 to 1 and 2600 °F firing temperature exhausts to an unfired HRGS, where steam is provided for steam turbine at 2400 psig/1000 °F/2.5" HgAbs. Process air is extracted from the compressor exhaust, precooled in an air-to-condensate heat exchanger, and then boosted to a pressure level adequate for the following fuels system.

Table 3-1

SUMMARY OF INTEGRATED FIXED-BED
ENTRAINED-BED COMBINED CYCLE SYSTEMS

Gasifier	Fixed-Bed	Entrained-Bed	
		Case B1	Case B2
Gas C.U. System	Benfield	Alkazid	
Gas Tb. MW (2)	361.0	300.4	299.0
Steam Tb. MW (1)	155.1	184.3	177.8
Aux. MW	11.9	21.0	22.5
Net Plant MW	504.2	463.7	454.3
Net Plant Hr (HHV)	8240.0	8312.0	8093.0
Net Plant (HHV)	41.42	41.06	42.17

High-pressure/temperature water from the gas turbine nozzle cooling system provides the first stage of heating for the incoming saturated low-Btu coal gas, and is then introduced into the multiple-flash system as a source of low-pressure steam that is inducted into the steam turbine. The second stage of low-Btu gas heating is provided by hot condensate from the booster precooler. Two-thirds of the bucket cooling water is vaporized in the gas

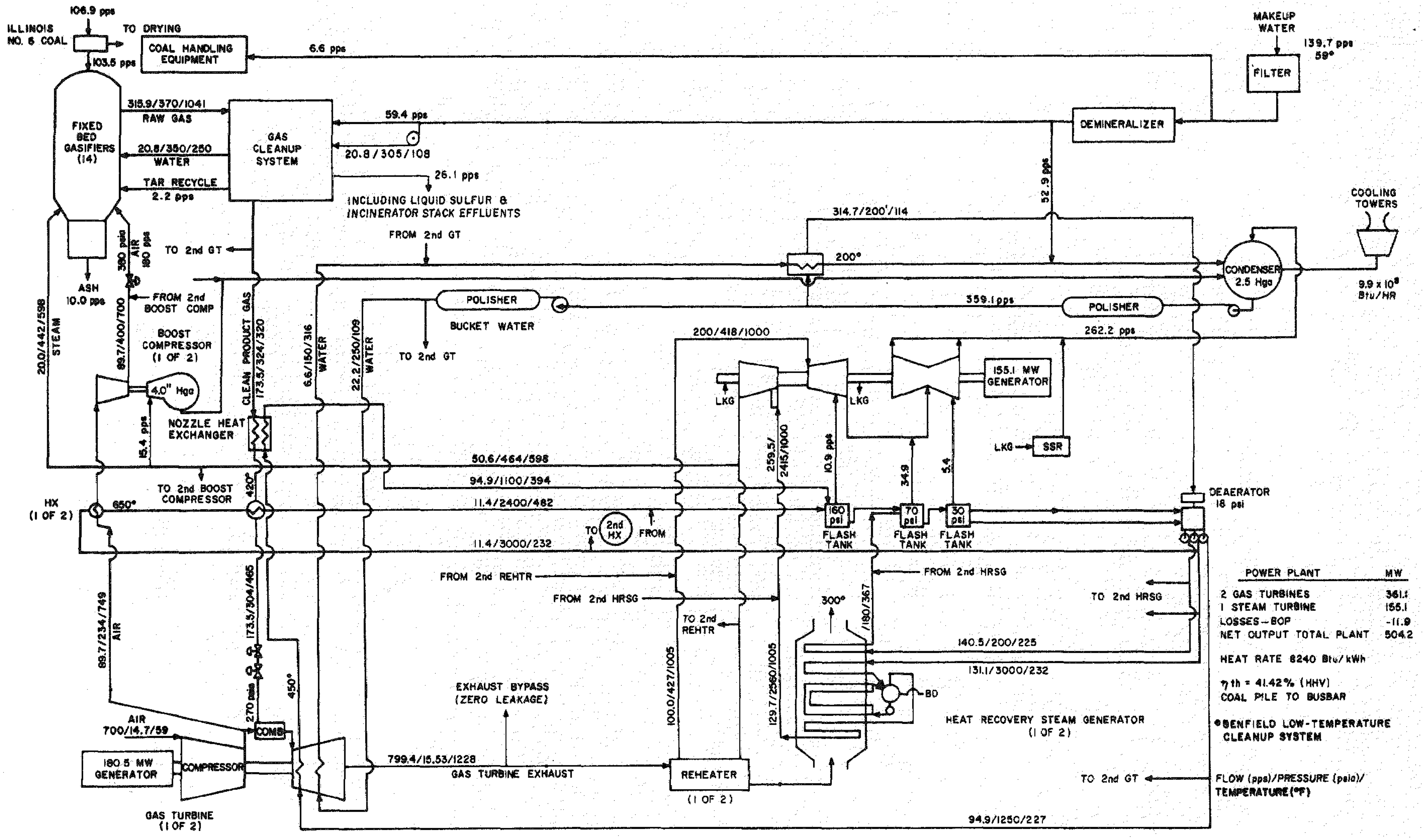


Figure 3-1. Schematic for the Integrated Low-Btu CGS-CC System with the Advanced Fixed-Bed Gasification System and Using the Reference Water-Cooled Gas Turbine Design Concept

turbine bucket cooling circuits and entrained in the gas turbine flow. The remaining third is recovered at the gas turbine and cooled in a closed heater before returning to the condenser hot well.

The booster compressor is driven by steam from the steam turbine's cold reheat point. The 700 pps compressor flow represents a realistic basis for both the gas turbine and overall system designs. The compressor aerodynamic design is based on a General Electric MS-7001 machine with a zero stage added at the inlet, two additional stages at the outlet, and a scale factor of 1.05.

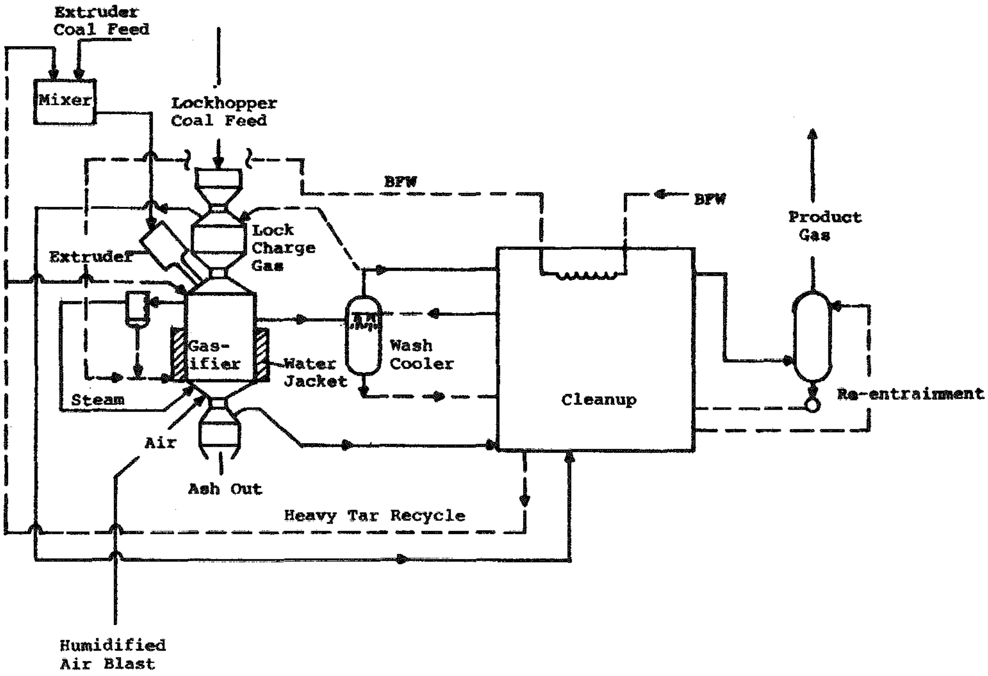


Figure 3-2. Advanced Fixed-Bed Fuel System

The advanced fixed-bed gasifier, Figure 3-2, is characterized by a low steam-to-air ratio, which not only reduces the overall cycle degradation resulting from extracting process steam but also maximizes the gasification efficiency in terms of gas heating value to coal pile energy. In addition, the generation of ammonia is at a level which precludes the need for a separate ammonia removal step in the gas cleanup process. Approximately half of the gasifier's process steam requirements are provided by the gasifier jacket steam; the balance is furnished from the steam turbine cold reheat point. Particulates and heavy tars in the raw gases from the gasifier at 1091 °F are removed by water-scrubbing in the raw gas quench. The heavy tar, blended with the dried coal from the coal crushing and classifying system, is recycled to the gasifier, thereby enabling full use of the as-received coal. The tars are cracked to lighter oils and phenols. The saturated raw quench gas at about 320 °F is further cooled to

185 °F before going to the Benfield hot potassium carbonate process for H_2S removal (Figure 3-3). During this cooling, water and some of the entrained light oils and phenols are condensed. The heat available from cooling the raw gas is used to regeneratively heat and saturate the cleaned gas with water, condensed light tars, and phenols. About 25% of the heat to the saturator is supplied by supplemental heating of the circulating water with condensing 150 psig steam, which is furnished by the Claus plant boiler.

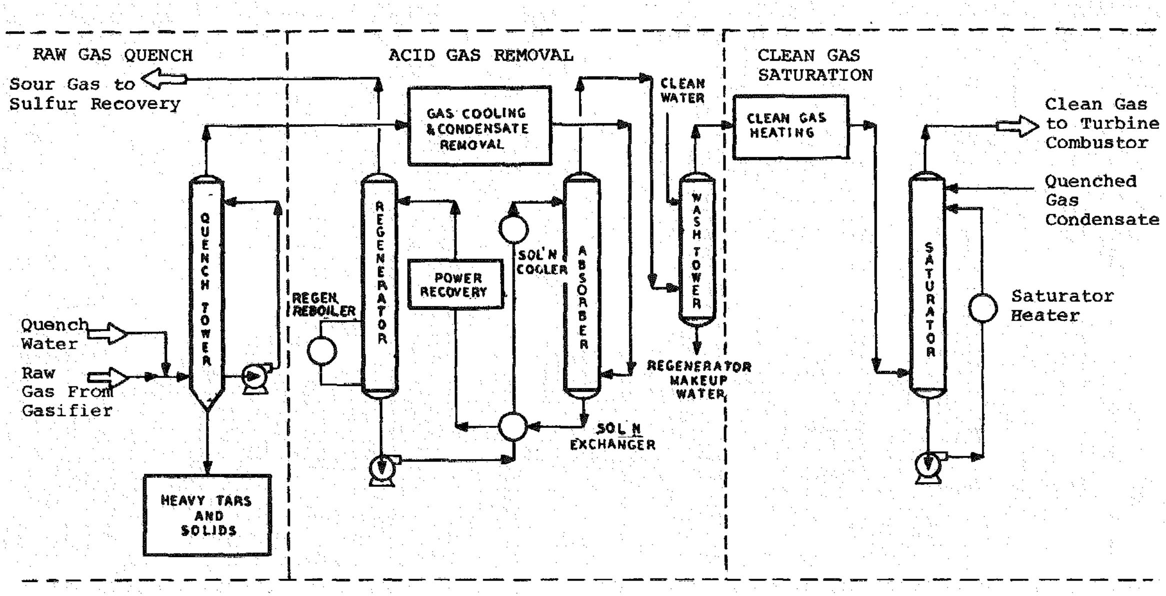


Figure 3-3. Low-Temperature Gas Cleanup Systems - GE/ERDA High-Temperature Turbine Technology Program

3.3.2 Selection of Steam Conditions

Parametric studies during Phase I confirmed the selection of a 16 to 1 compressor pressure ratio at 2600 °F and the use of the steam conditions of 2400 psig/1000 °F/1000 °F/2.5" HgAbs; the results of these studies are shown on Figure 3-4 for low-temperature cleanup. Note that a pressure of 16 to 1 is about optimum at 2600 °F with steam conditions of 2400 psig/1000 °F/1000 °F/2.5" HgAbs. It is also seen to result in a substantial improvement in overall plant performance at 3000 °F. A selection of 2400 psig throttle pressure, rather than either 1800 psig or 3500 psig, was made on the following basis:

A. 2400 psig/1000 °F/1000 °F/2-1/2" HgAbs steam conditions at 2600 °F and 16 to 1 pressure ratio offers about 0.7% improvement in overall plant heat rate relative to 1800 psig, and is only 0.35% poorer than with 3500 psig/1000 °F/1000 °F/2-1/2" HgAbs.

B. A higher pressure ratio of about 20:1 would be required to achieve the marginally higher efficiency at 3500 psig.

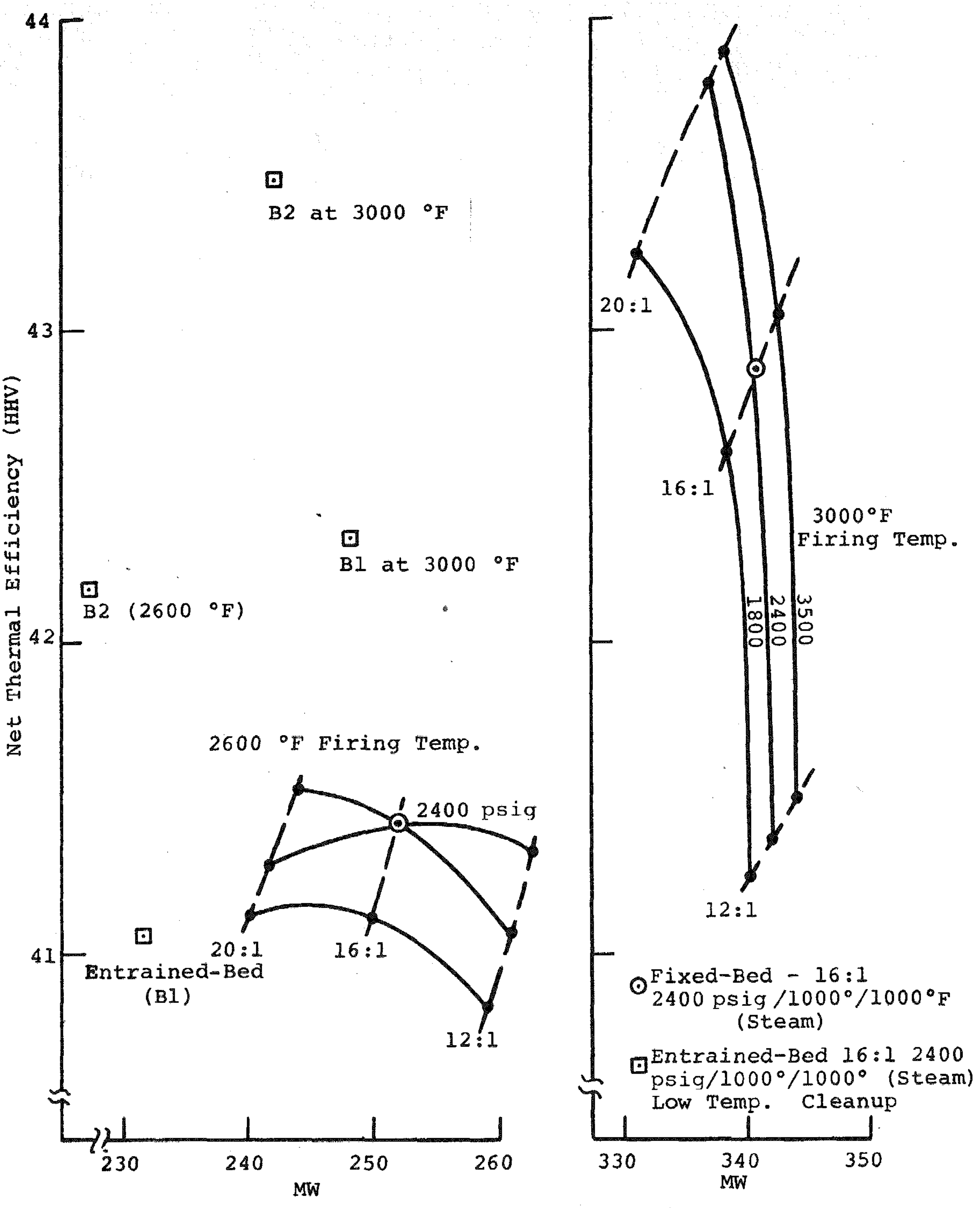


Figure 3-4. Trends in Combined Cycle Characteristics with Pressure Ratio, Firing Temperature, and Steam Conditions

C. A throttle pressure of 3500 psig introduces the design and operating problems associated with "once-through" technology and more demanding water cleanup for questionable gains.

D. A throttle pressure of 2400 psig is uniquely suitable for the larger capacity machines that will be most favorable for baseload operation.

E. At 3000 °F firing temperature, 2400 psig/1000 °F/1000 °F/ 2-1/2" HgAbs steam conditions, and 16 to 1 pressure ratio offer about 0.6% improvement relative to 1800 psig/1000 °F/ 1000 °F/2-1/2" HgAbs, which is only about 0.5% poorer than with 3500 psig/1000 °F/1000 °F/2-1/2" HgAbs.

3.3.3 Effects of Low-Temperature and High-Temperature Gas Cleanup

The use of high-temperature cleanup eliminates the irreversible losses associated with water-scrubbing and cooling the raw gases ahead of the low-temperature cleanup system, and the loss of high-pressure carbon dioxide in the absorption process. The recovery of these and other losses in the low-temperature cleanup system, minus the losses associated with the regeneration of the absorbant and the recovery of the detrained sulfur can result in a significant improvement in overall plant efficiency, as indicated on Figure 3-5.

Note that the overall plant efficiency with high-temperature scrubbing at 2600 °F and 16 to 1 pressure ratio is from 41.42% to 42.81%, but is accompanied by a reduction in specific work from 360. kW/pps to 320. kW/pps, which will tend to increase the cost per kW of plant output.

Note that designing for a 200 °F increase in turbine stationary and rotor hardware metal surface temperature not only improves the performance from 41.42 percent to 42.18 percent; it also increases the plant specific work from 360.1 kW/pps to 364.3 kW/pps. Both of these tend to reduce generation costs. This point is made to indicate the magnitude of the influence coefficient. Going to the higher surface temperature is not recommended because there would be a resulting penalty in hot parts life.

3.3.4 The Integrated Entrained-Bed CGS-CC System

The fixed-bed CGS-CC system is, of course, the basis of this OPDD and was selected as a result of a comparative appraisal relative to the entrained-bed CGS-CC system, which will be discussed in Section 4.3.4. Consequently, data for the latter systems are reported in this section in order to indicate the basis for the comparative appraisal and system selection.

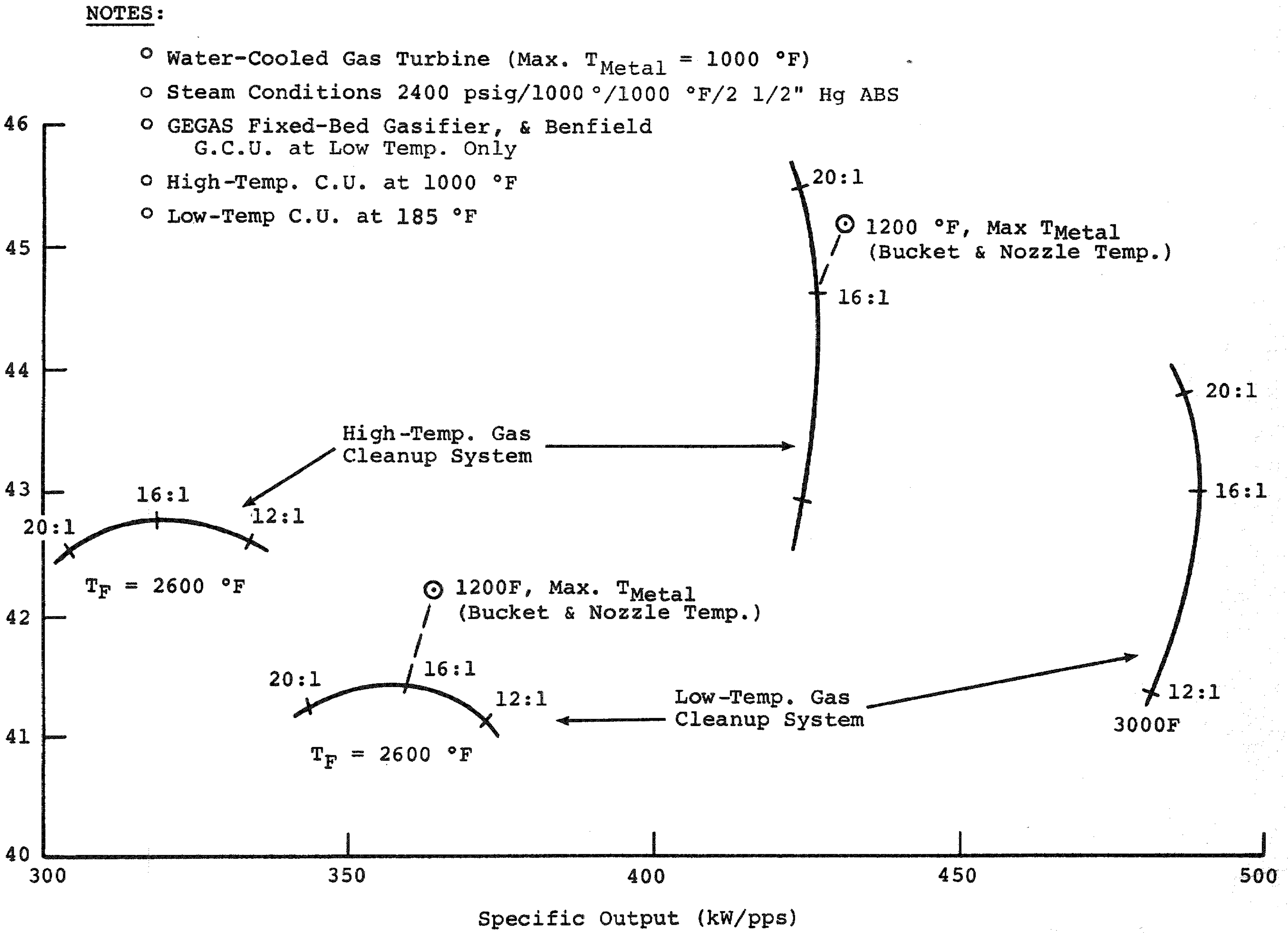


Figure 3-5. Trends In Combined Cycle Performance With Type of Gas Cleanup System, At Various Pressure Ratios

The entrained-bed gasification system, Figure 3-6, is characterized by a high raw gas temperature exiting the gasifier, about 1700 °F. To utilize low-temperature gas cleanup, the raw gas temperature must be reduced through the use of a waste heat boiler (WHB), a regenerative raw gas to clean gas heater, or a combination of these heat exchangers. The regenerative heat exchanger enables the heat to be utilized at the highest efficiency, i.e., in the gas turbine combustor, but is considered to be developmental from the standpoint of technological readiness within six years. Consequently, two entrained-bed system configurations have been studied: Case B1, Figure 3-6, utilizing only the waste heat boiler for the nearer term application of the entrained-bed CGS-CC system; and Case B2, Figure 3-7, utilizing the more efficient arrangement of waste heat boiler and regenerative gas heater for the best overall plant performance.

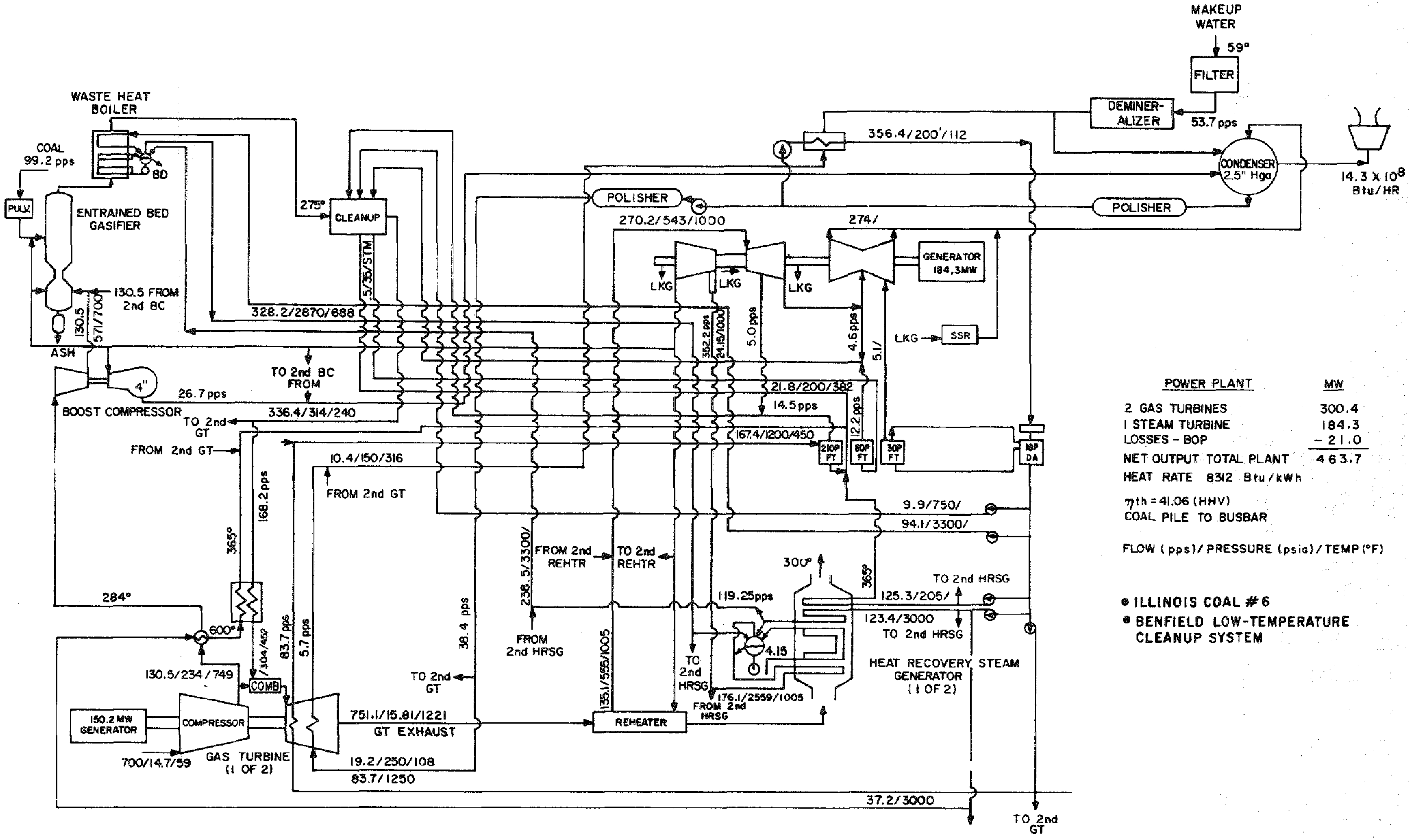
In the entrained-bed gasification system, Figure 3-8, the pulverized coal is lock-hoppered to injection pressure and then blown into the gasifier by clean recirculated product gas. Upon injection into the upper section of the gasifier, the coal is devolatilized: the char, after leaving the gasifier, is removed from the gas stream by inertial separators, cooled, and then reinjected into the lower (gasification) section of the gasifier, which operates well above the slagging temperature. The slag exits the gasifier at the bottom, and the hot gases flow upward, entraining and devolatilizing the incoming pulverized coal. Ammonia is produced at a level requiring a removal system in order to meet NO_x requirements.

For Case B1 (Figure 3-6), in order to optimize the system, evaporation in the WHB is maximized by setting the minimum gas - water/steam temperature differential (the pinch point) at the gas exiting the evaporator section: the remaining heat in the raw gas after the evaporator provides only about 28.% of the economizing duty required for the steam generation in the WHB. The balance of the economizing duty for the WHB is provided by the HRSG's; they also furnish all of the superheating and reheating duty, plus a small amount of evaporative duty.

For Case B2 (Figure 3-7) the raw gas exits the WHB at a temperature high enough to permit regenerative heating of the clean product gas to 800 °F, thereby considerably reducing the generation of high pressure steam in the WHB. The HRSG's must now provide all of the economizing, superheating, and reheating duty, in addition to a somewhat larger quantity of steam generation than in Case B1.

3.3.5 Comparative Combined Cycle Performance

Performance of the fixed-bed CGS-CC system and the two entrained-bed CGS-CC systems described in Sections 3.3.3 and 3.3.4 is summarized in Table 3-1. The fixed-bed system (Figure 3-2) has an overall plant efficiency about 0.9% better than that



POWER PLANT	MW
2 GAS TURBINES	300.4
1 STEAM TURBINE	184.3
LOSSES - BOP	- 21.0
NET OUTPUT TOTAL PLANT	463.7

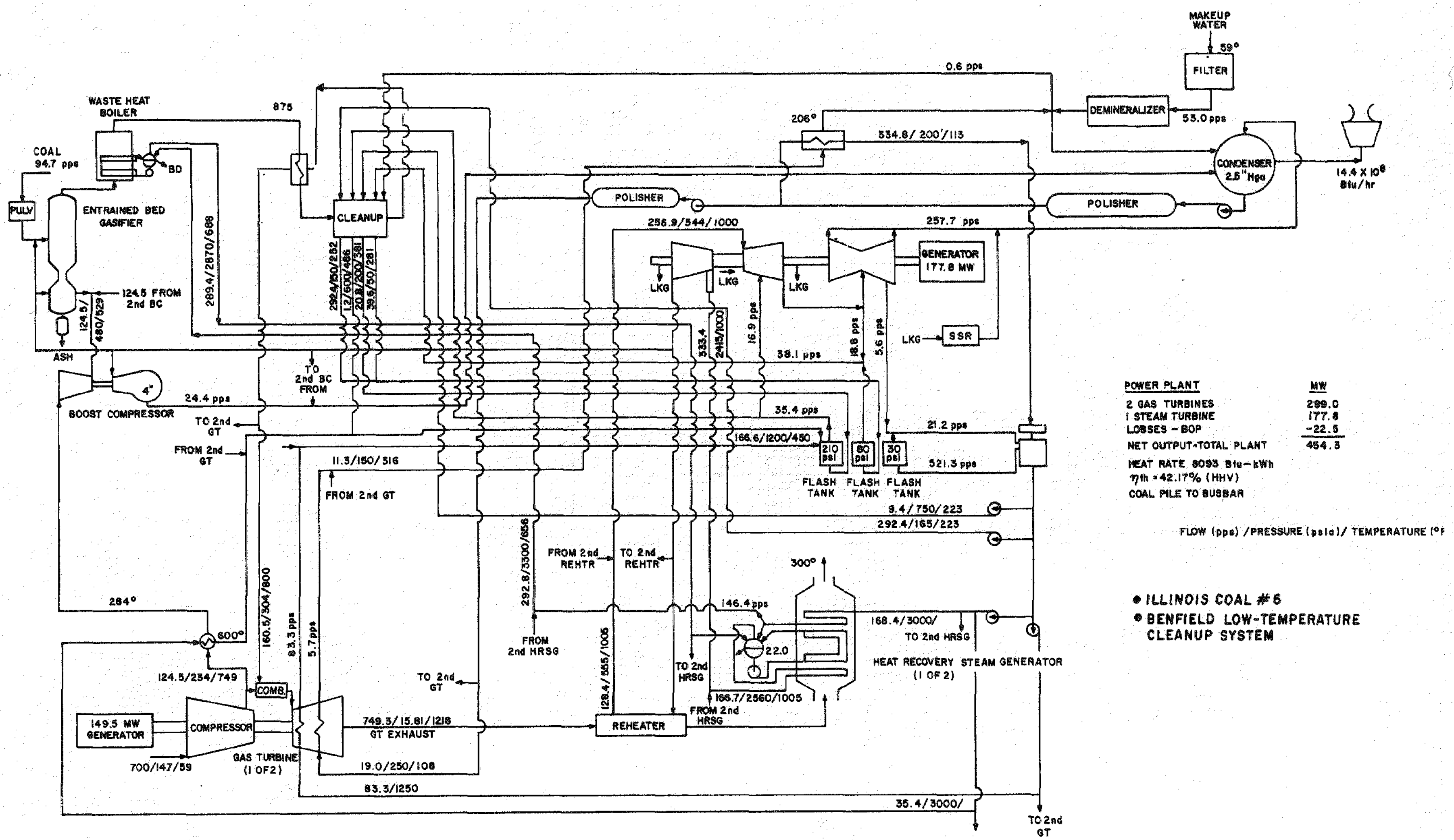
HEAT RATE 8312 Btu/kWh

ηth = 41.06 (HHV)
COAL PILE TO BUSBAR

FLOW (pps)/PRESSURE (psia)/TEMP (°F)

- ILLINOIS COAL #6
- BENFIELD LOW-TEMPERATURE CLEANUP SYSTEM

Figure 3-6. EB-CGS-CC, Case B1



POWER PLANT	MW
2 GAS TURBINES	299.0
1 STEAM TURBINE	177.8
LOSSES – BOP	-22.5
NET OUTPUT-TOTAL PLANT	454.3

HEAT RATE 8093 Btu–kWh
η_{th} = 42.17% (HHV)
COAL PILE TO BUSBAR

- ILLINOIS COAL #6
- BENFIELD LOW-TEMPERATURE CLEANUP SYSTEM

Figure 3-7. EB-CGS-CC, Case B2

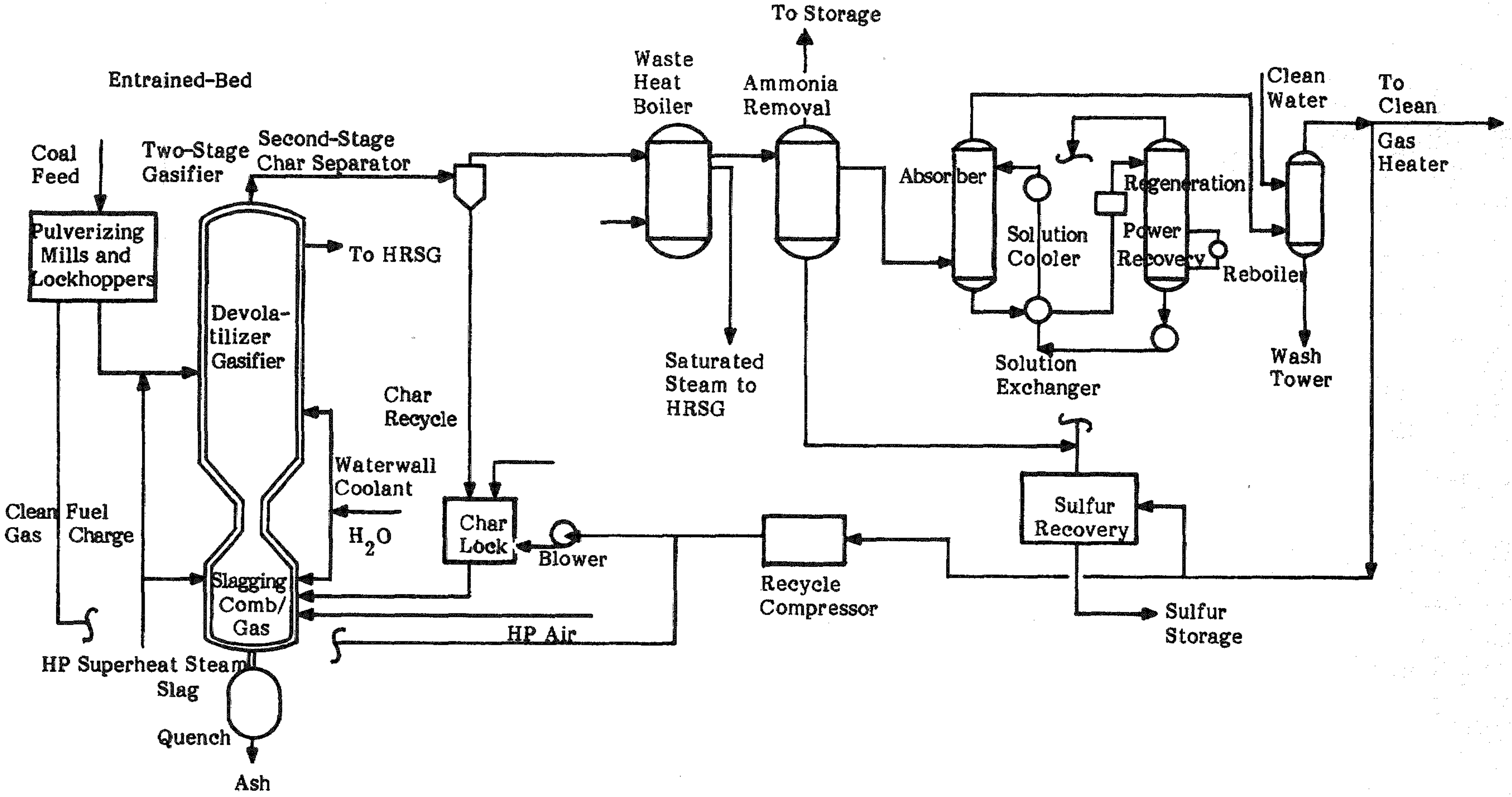
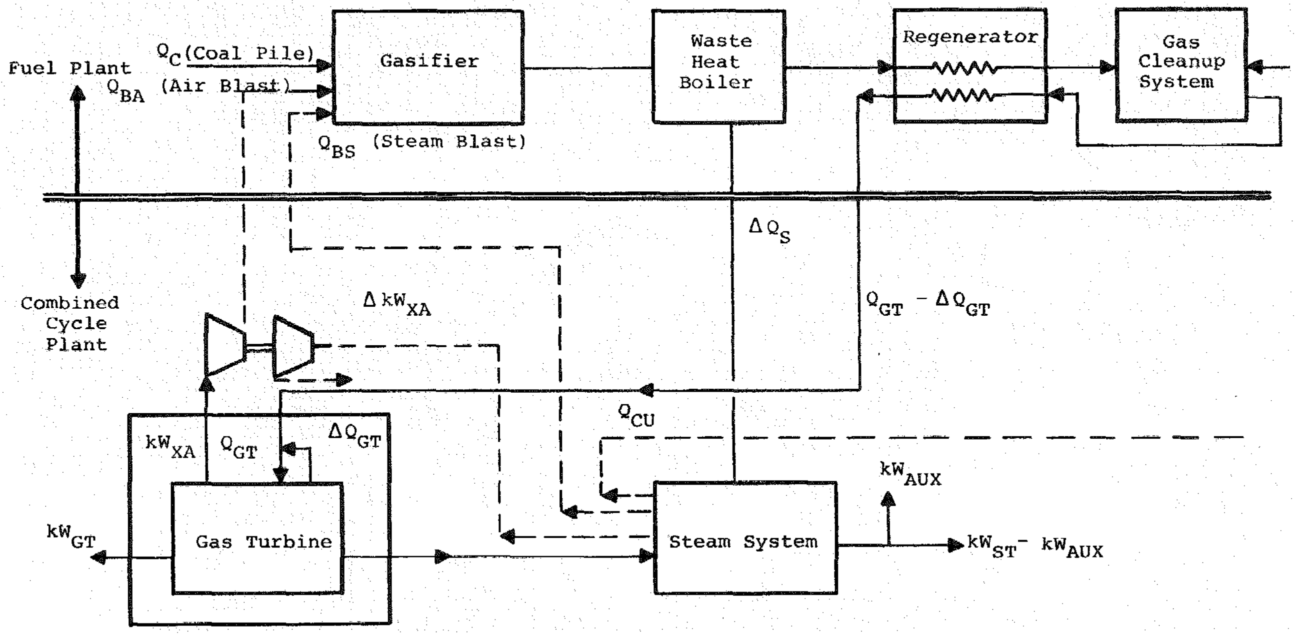


Figure 3-8. Entrained-Bed Gasification System

of the nearer term entrained-bed system (Figure 3-6), which utilizes a waste heat boiler for cooling the raw product gas ahead of the gas cleanup system. This fixed-bed system is also characterized by 20.1% greater net gas turbine output, 15.8% lower steam turbine output, and an 8.7% greater net plant output.

The entrained-bed CGS-CC system utilizing both WHB and regenerative gas heating for cooling the raw product gas, Case B2 (Figure 3-7) has a better overall plant efficiency (about 1.8% better) than that of the fixed-bed system. In addition, there is a further reduction in net gas turbine and overall plant output because of the effects of the regenerative gas heater in reducing both the thermal energy to the steam system and the mass flow to the gas turbine itself.

The simplified heat flow diagram for integrated coal gasification combined cycle systems (Figure 3-9) shows the major subsystems and components, and the major heat and power rates which will be considered in comparing the three CGS-CC systems. There are two major systems indicated - the fuel plant (shown above the line) and the combined cycle (shown below the line).



Note: See Table 3-2 for definition of nomenclature and calculation of subsystem and overall plant efficiencies

Figure 3-9. Generalized Heat and Energy Distribution - Integrated CGS-CC System

The fuels plant includes the gasifiers, cleanup system, and, in some cases, a waste heat boiler and a regenerative low-Btu gas-to-gas heater. The combined cycle plant includes the gas and steam turbine systems and the steam turbine-driven booster air compressor. The fuels plant and combined cycle are highly integrated in order to minimize the losses associated with furnishing process air and steam.

In order to properly appraise the effects of extracting process air from the gas turbine, the gas turbine performance is credited for the power input to this air; this incremental power can then be treated as additional auxiliary power, chargeable to the fuels plant. In the same manner, the steam system is credited with the power required for the booster air compressor, plus the power equivalent of steam that is furnished to the fuels plant; this incremental, equivalent power is also treated as an additional auxiliary power, also chargeable to the fuels plant. A set of "pseudo" gas turbine, steam turbine, and nonintegrated combined cycle performance data can then be calculated.

The appraisal of the three CGS-CC systems will make use of the "pseudo" system performance data described above and will make use of various system parameters as described on Table 3-2. In summary, the appraisal will be based on a calculation of the three systems in the following manner:

$$\eta_{OA} = \eta_{GT} \times CF_{SC} \times CF_{RC} \times CR_{CC} \times CF_{GA} \times CF_{GE}, \qquad \text{(Equation 1)}$$

wherein: η_{OA} = Overall CGS-CC efficiency (HHV)

η_{GT} = Gas turbine simple-cycle efficiency (LHV); (Eq. A on Table 3-2)

CF_{SC} = Correction factor to obtain the "pseudo" gas turbine simple-cycle efficiency (LHV); (Eq. B of Table 3-2)

CF_{RC} = Correction factor to obtain the pseudo regenerative cycle gas turbine efficiency (LHV); (Eq. C of Table 3-2)

CF_{CC} = Correction factor to obtain pseudo combined cycle efficiency (LHV); (Eq. D of Table 3-2)

CF_{GA} = Correction factor to obtain actual combined cycle efficiency (LHV); (Used in Eq. E of Table 3-2)

CF_{GE} = Correction factor to obtain bus-bar to coal pile overall cycle efficiency (HHV); (Used in Eq. E of Table 3-2)

It will be seen that these various correction factors represent grouping of significant parameters and variables resulting from detailed system calculations. Consequently, Equation 1 and the factor are intended to provide a basis for the comparative appraisal of the various systems, and, in itself, is not a basic method.

Direct use of the simple-cycle gas turbine efficiency and the pseudo-simple-cycle efficiency is especially appropriate, not

Table 3-2

METHOD FOR ANALYZING PERFORMANCE OF INTEGRATED COMBINED CYCLE SYSTEMS

- Simple Cycle Gas Turbine Eff. = $\eta_{GT} = \frac{kW_{GT}}{Q_{GT}} \times 3413$, Equation (A)

  wherein: kW_{GT} = Gas Turbine-Gen. kW

  $Q_{GT} = Q_{GTC} + Q_{GTS} + Q_{GTL}$

  wherein: Q_{GTC} = LHV Chemical Heat to Gas Turbine (Btu/hr)
  Q_{GTS} = Sensible Heat (59 °F Basis) to Gas Turbine
  Q_{GTL} = Latent Heat of Water Entrained in Low-Btu Gas

- Pseudo Gas Turbine kW = $kW^{1}_{GT} = kW_{GT} + kW_{XA}$,

  wherein: kW_{XA} = kW to Extracted Air by Gas Turbine Compressor

- Pseudo Simple Cycle Gas Turbine Eff. = $\eta^{1}_{GT} = \eta_{GT} \times \left(1 + \frac{kW_{XA}}{kW_{GT}}\right) = \eta_{GT} \times CF_{SC}$ Equation (B)

- Pseudo Regenerative Cycle Gas Turbine Eff. = $RC\ \eta^{1}_{GT} = \eta^{1}_{GT} \times \frac{1}{1 - \frac{\Delta Q_{GT}}{Q_{GT}}} = \eta^{1}_{GT} \times CF_{RC}$, Equation (C)

  wherein: ΔQ_{GT} = Heat to Low-Btu Gas, Received by Generative Heating from High-Temperature Steam or Water; Relative to Q_{GT} (LHV)

- Pseudo Steam Turbine kW = $kW^{1}_{ST} = kW_{ST} + \Delta kW_{ST}$,

  wherein: kW_{ST} = Steam Turbine-Generator kW

  $\Delta kW_{ST} = \Delta kW_{XA}$, (= kW to Booster Air Compressor)

  $+ kW_{G.ST}$, (= kW Equivalent of Process Steam to Gasifier)

  $+ kW_{C.U.ST}$, (= kW Equivalent of Steam to C.U. System)

- Pseudo Combined Cycle Eff = $\eta^{1}_{CC} = RC\ \eta^{1}_{GT} \times \frac{\left(1 + \frac{kW^{1}_{ST} - kW_{AUX}}{kW^{1}_{GT}}\right)}{\left(1 + \frac{\Delta Q_{S}}{Q_{GT} - \Delta Q_{GT}}\right)} = RC\ \eta^{1}_{GT} \times CF_{CC}$, Equation (D)

  wherein: ΔQ_{S} = Incremental Heat (LHV, Btu/hr) to Steam System by Fuel Plant WHB, Supplementary Firing, etc.

  kW_{AUX} = B.O.P. Auxiliary kW (From BUS)

- Pseudo Combined Cycle kW - $kW^{1}_{CC} = kW^{1}_{ST} + kW^{1}_{GT} - kW_{AUX}$

- Overall Plant Efficiency = $\eta_{OA} = \eta^{1}_{CC} \times \left(1 - \frac{kW_{XA} + \Delta kW_{ST}}{kW^{1}_{CC}}\right) \times \eta_{CG} = \eta^{1}_{CC} \times CF_{GA} \times CF_{GE}$, Equation (E)

  wherein: $\eta_{CG} = \eta_{TG} \times \frac{\eta_{CG}}{\eta_{TG}}$,

  wherein: $\eta_{TG} = \frac{Q_{GT} - \Delta Q_{GT} + \Delta Q_{S}}{Q_{C} + Q_{BA} + Q_{BS}}$

  wherein: Q_{C} = Heat from Coal Pile (HHV)

  Q_{BA} = Sensible Heat in Blast Air Relative to Coal Temperature

  Q_{BS} = Total Heat in Blast Steam Relative to Coal Temperature (Including Latent Heat) only because it is an index of gas turbine performance, but also because, in the basic heat recovery type of combined cycle, all of the primary heat input to the overall system enters at the gas turbine combustor. It should be emphasized that the heat input to the gas turbine includes chemical, sensible, and the latent heat associated with the water vapor in the gas before combustion; the latter quantity does not include, of course, the water of formation resulting from the subsequent combustion. The latent heat is not usually a factor in gas turbine applications, since conventional gas turbine fuels are practically dry. However, the FB-CGS-CC system is unique because of the significant quantity of water vapor that is entrained in the gas as a means of recovering a large proportion of the sensible heat (water) which is used in scrubbing the raw gas.

When regenerative low-Btu gas heating is used, the simple-cycle gas turbine efficiencies must be modified to the so-called regenerative cycle basis, which properly infers the actual gas turbine heat required from the fuels plant; this regenerative heating may be from either the gas turbine or the steam system portion of the combined cycle. It should be noted that this type of regenerative heating utilizes residual heat in the working fluids at temperatures that are well below their maximum, which results in significantly improved overall plant efficiencies. Both the FB-CGS-CC and the EB-CGS-CC, Case B1, systems use this type of gas heating.

However, in the EB-CGS-CC, Case B2, high-level primary heat directly from the fuels plant is used to heat the low-Btu gas, rather than generate steam. This is a different form of regenerative heating, having an inherently lower potential for improvement in plant efficiency.

For the FB-CGS-CC system, the correction factor CF_{CC} implies that the incremental plant output results from recovering the gas turbine exhaust heat in the steam bottoming cycle. For the EB-CGS-CC systems, the exhaust heat to the steam system is augmented by primary heat from the fuel plant's WHB. Consequently, since the steam system is inherently less efficient than the overall plant, the EB-CGS-CC systems will show less improvement than the FB-CGS-CC system, relative to the regenerative gas turbine system.

Throughout this discussion, and as indicated in the method and equations shown on Table 3-2, is the use of the pseudo level of performance, so that all of the losses associated with the fuels plant can be identified and properly charged; as indicated in other areas, these losses include the total power required for furnishing process air, plus the power equivalent of the process steam to the fuel plant. The overall system loss inferred in CF_{GA} is directly chargeable to the fuels plant.

Throughout the preceding discussion and in the development of the correction factors on Table 3-2, all heat quantities, and hence efficiencies, are on the basis of lower heating value. This is a practical approach because the effects on the combined cycle resulting from differential quantities of water of formation, a function of HHV/LHV, are very small. The overall system efficiency must, of course, be expressed on a higher heating value basis; the correction factor CF_{GE} makes this conversion.

The various factors indicated in Equation 1 and calculated in accordance with Table 3-2 are summarized in Table 3-3 and, for comparative purposes, plotted on Figure 3-10, where the generic differences in the systems are very pronounced.

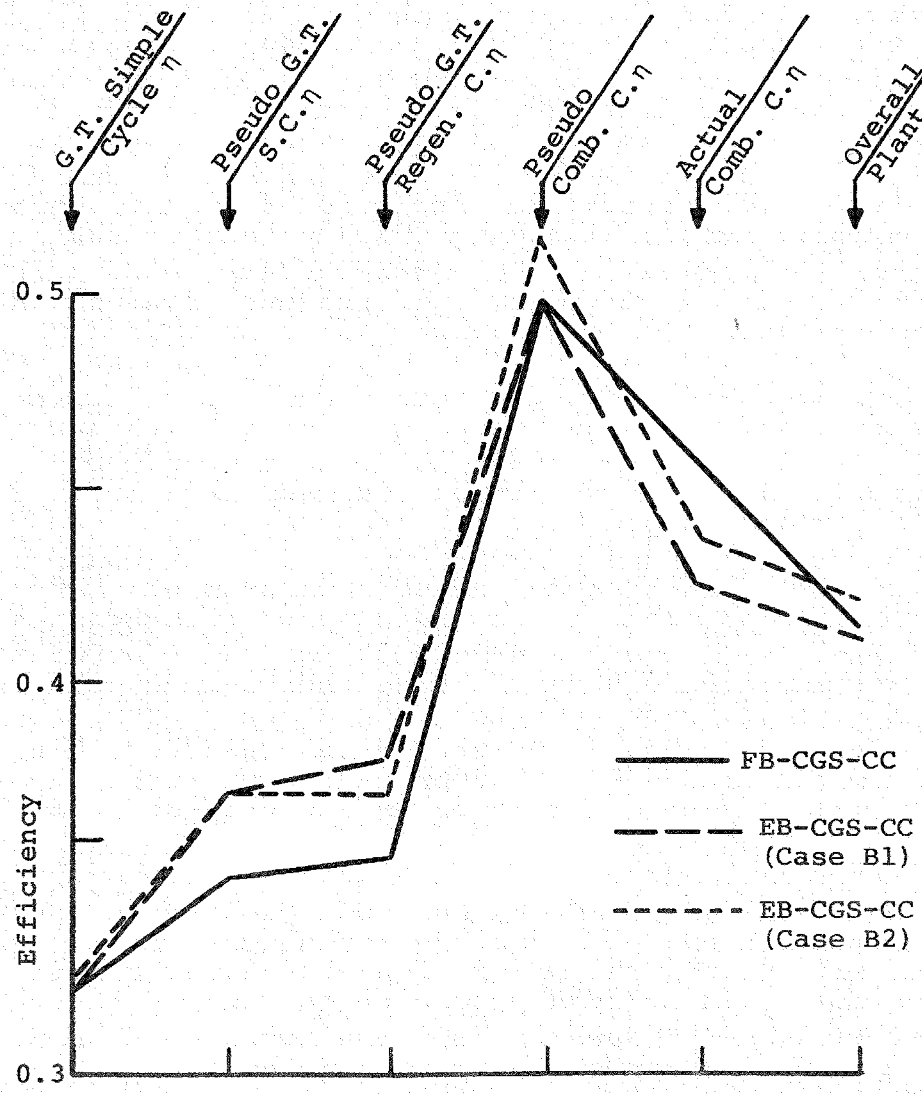


Figure 3-10. Performance Trends in Integrated CGS-CC Plants

Table 3-3

SYSTEM PERFORMANCE SUMMARY

	Performance Factors	FB-CGS-CC	EB-CGS-CC (Case B1)	EB-CGS-CC (Case B2)
1.	(1) Simple Cycle η On Basis of Gen.	0.3204 -	0.3212 -	0.3228 -
2.	(1) Pseudo Simple Cycle Gas Tb. η/CF_{SC}	0.3489/1.0890	0.3712/1.1557	0.3710/1.1493
3.	Pseudo Regenerative Cycle Gas Tb. η/CF_{RC}	0.3545/1.1061	0.3801/1.0241	0.3710/1.0000
4.	$(1 + \frac{\text{Net Pseudo St. Sys kW}}{\text{Pseudo Gas Tb. kW}}) \div (1 + \frac{\Delta Q_{ST\ Sys}}{Q_{GT} - \Delta Q_{GT} - \Delta Q_S})/CF_{CC}$	$\frac{1.4095}{1}/1.4095$	$\frac{1.5712}{1}/1.3124$	$\frac{1.5621}{1.1231}/1.3910$
5.	(2) Pseudo Combined Cycle η	0.4997 -	0.4988 -	0.5161 -
6.	Actual Combined Cycle η/CF_{GA}	0.4547/0.9100	0.4240/0.8501	0.4368/0.8464
7.	Overall Plant η/CF_{GE}	$\underline{\underline{0.4142}}$/0.9110	$\underline{\underline{0.4106}}$/0.9681	$\underline{\underline{0.4217}}$/0.9655
8.	Effective Gasifier $\eta/CF_{GA} \times CF_{GE}$ (LHV/HHV Basis)	0.8290	0.8230	0.8172

NOTES:

(1) Pseudo Gas Tb. η's Credits Gas Tb. System For Power To Extracted Process Air.

(2) Pseudo Comb. Cycle η Credits Gas Tb. As Indicated In Note (1), Plus the Steam Tb. For Booster Comp. Power & Power Equivalent Of Process Steam To Fuels Plant.

The simple-cycle efficiency of the FB-CGS-CC system is marginally poorer than for the EB-CGS-CC, Case B1, system, in spite of the fact that the latent heat which is charged to the gas turbine cycles depreciates the FB system by 6.7% and the EB systems by less than 0.1%. About 10% of the effect of this different proportion of latent heat charged to the gas turbine system is offset by the greater expansivity of the fuel-entrained water vapor, and the balance by the smaller quantity of process air that is extracted from the compressor. This latter effect is illustrated by the relative changes in the gas turbine efficiencies when going from the simple-cycle to the pseudo-simple-cycle basis; as mentioned previously, in the pseudo gas turbine efficiencies, the gas turbines have been credited with the power to the extracted air.

With respect to the EB-CGS-CC, Case B2, system, note that its gas turbine simple-cycle efficiency is about 0.5% better than that of Case B1, reflecting the small decrease in extracted process air resulting from the higher total heat content per pound of hotter (800F vs 452 °F) low-Btu gas. Note that the pseudo efficiency levels for Cases 1 and 2 are almost identical.

With respect to regenerative heating from within the combined cycle, the low-Btu gas is heated from 320 to 465 °F in the FB-CGS-CC system and from 240 to 452 °F in the EB-CGS-CC, Case B1; there is no additional heating of the relatively hot (800 °F) gas in the EB-CGS-CC, Case B2. As indicated in Figure 3-10, the trend of the correction factors in going to the regenerative cycle efficiency levels reflects these relative heat additions.

The FB-CGS-CC system shows a 40.95% improvement in the pseudo regenerative gas turbine cycle efficiency resulting from the effects of the steam bottoming cycle (CF_{CC} of line 4 in Table 3-3). The EB-CGS-CC, Case B1, shows only a 31.24% improvement, reflecting the degradation of adding incremental primary heat from the fuel plant to the less efficient steam system via the WHB; as indicated by the data in line 4, columns 3 and 4 of Table 3-3 the incremental steam power does not keep pace with the incremental heat added.

For the EB-CGS-CC, Case B2, a portion of the primary heat is shifted from the steam system (WHB) to the low-Btu gas in a regenerative raw-to-clean gas heater, with a reduction in the degradation noted for Case B1, CF_{CC}. The degradation is reduced still further by the allocation of nonchargeable heat from the gas turbine cooling system; in Case B1 this heat was utilized in heating the gas. The net effect is that the incremental steam turbine power almost keeps pace with the chargeable incremental heat to the steam system; note that the value of CF_{CC} (line 4, column 6) is approaching that for the FB-CGS-CC system (line 4, column 2).

The high levels of pseudo combined cycle efficiency are indicated in Figure 3-10 and on line 5 of Table 3-3. As indicated by CF_{GA} (line 6), the EB systems have significantly higher requirements for providing air and steam to the fuels plant.

The correction factor for overall fuels plant thermal efficiency, as shown on line 7, CF_{GE}, in columns 2, 4 and 6, relates the LHV heat of the combined cycle to the HHV heat in the coal pile (only). The relatively large difference between the FB and EB systems reflects, principally, a higher HHV/LHV ratio with respect to the clean product gas for the FB system and the inefficiencies associated with water-scrubbing the raw gas; the scrubbing process itself has a high degree of irreversibility because of the large temperature difference between the gas and scrub water, and, also, a portion of the vaporized scrubbing water is not recoverable in the subsequent regenerative resaturator.

3.3.6 Comparative Entrained-Bed and Fixed-Bed Performance With Low- and High-Temperature Gas Cleanup Systems

Table 3-4 presents a performance summary for the advanced FB-CGS-CC and the two EB-CGS-CC plants, with both low- and high-temperature gas cleanup systems.

The data in columns 1 and 2 for the FB-CGS-CC system is for those points at 16:1 on Figure 3-5.

Both the Bureau of Mine's iron oxide system and the Consolidated Coal Company's partially calcined dolomite process have been considered for the EB-CGS-CC system, with the associated performance characteristics shown in columns 4 and 5, Table 3-4, respectively.

In the arrangement with the Bureau of Mines system, the WHB cools the gas only to 1200 °F. Consequently, the heat below 1200 °F will be utilized at fuel combined cycle efficiency (about 50%), rather than at the lower steam cycle efficiency (about 40%). It has been assumed that the other losses for both the low- and high-temperature cleanup systems are off-setting; the resulting improvement resulting from high-temperature cleanup is 1.39 points, or 3.4%. Note that the gas turbine power has decreased only about 1%, from 300.4 MW to 297.9, resulting from the reduction in fuel flow. This is in sharp contrast to the FB-CGS-CC system, wherein the gas turbine output dropped by 12.1% because of the elimination of the gas resaturation process.

In the arrangement with the Consolidated Coal Company system, the H_2S is removed from the raw gas immediately following the gasification process, by reacting with half-calcined dolomite in a fluidized bed reactor at about 1600 °F. The particulates are then removed by inertial and electrostatic precipitation. The absorbent is continuously recycled through a fluidized-bed regenerator, where CO_2 is contracted and H_2S is stripped to feed a liquid Claus plant. Sulfur is precipitated by reacting with dilute sulfurous acid.

Table 3-4

COMBINED CYCLE PERFORMANCE WITH LOW-TEMPERATURE AND HIGH-TEMPERATURE GAS CLEANUP SYSTEM

	Fixed Bed		Entrained Bed (B1)			(B2)
	Low T.	High T.	Low T.	High T.(1)	High T.(2)	Low T.
2-Gas Turbine MW	361.1	317.5	300.4	297.9	296.6	299.0
1-Steam Turbine MW	155.1	139.6	184.3	159.1	138.1	177.8
Balance of Plant MW	11.9	9.9	21.0	21.6	20.5	22.5
Net Plant MW	504.2	447.2	463.7	435.4	414.2	454.3
Net Plant Efficiency (HHV)	41.42	42.81	41.06	42.45	42.76	42.17
Net Plant Efficiency (LHV)	43.66	45.13	43.29	44.76	45.07	44.45
Net Plant Heat Rate (Btu/kW-hr) (HHV)	8240.0	7972.0	8312.0	8039.0	7981.0	8093.0

(1) Morgantown, Bureau of Mines - Intermediate Temp. Gas Cleanup System

(2) Consolidated Coal Company - Hot Gas Cleanup System

Using the very-high-temperature gas cleanup system results in an even greater reduction in the degradation associated with utilizing the high-temperature energy in the steam cycle ahead of the low-temperature gas cleanup system. As indicated in column 5, Table 3-1, the result is an improvement of about 4.1%.

Note that the EB-CGS-CC, Case B2, through the use of the regenerative gas-to-gas heat exchanger, is already utilizing a significant proportion of the sensible heat in the raw product gases at full combined cycle efficiency. This system is summarized in column 6, Table 3-1, and a comparative appraisal relative to the FB-CGS-CC with low-temperature gas cleanup was presented in Section 3.3.5.

In summary, intermediate and high-temperature gas cleanup systems offer possible improvements in overall plant efficiency on the order of 3%. As previously mentioned, such systems have not been a factor in setting the functional and product specifications for the advanced high-temperature gas turbine developments in the time frame assumed for this HTTT program.

3.3.7 The Integrated CGS-CC System With Backup Gas Turbine Designs

Alternative hot gas path coolant systems were executed as a basis for verifying the water-cooled reference design and also to select a prime backup design. An all-air-cooled design, an all-steam-cooled design, and a design utilizing water-cooled nozzles and steam-cooled buckets has been investigated. The overall plant performance for the FB-CGS-CC systems with these alternative designs and also the water-cooled design is shown in Table 3-5.

Note that the efficiency of the water-cooled reference design, shown in column 1 at 41.42%, is 2.21 points (5.3%) better than the backup design (column 2) and 11.0% better than the all-steam-cooled design. The great increase in gas turbine power and the associated reduction in steam turbine power are the outstanding characteristics of steam cooling, reflecting the relocation of the steam as a working fluid from the steam turbine to the gas turbine. Note that the gas turbine output in the prime backup design (column 2) is about 30 MW greater than the water-cooled reference design, but the steam turbine output has deteriorated by approximately 56 MW, with a reduction in net plant output. In the case of the all-steam-cooled design, there is actually a greater increase in the output of the two gas turbines, 138 MW, than decline in steam turbine output, 91 MW, with a resulting increase in net overall plant output.

The all-air-cooled design shows decreases in output of 36% and 30% in the gas turbine and steam turbine, respectively, relative to the water-cooled reference design, with a 6.2% poorer net plant heat rate.

Table 3-5

PERFORMANCE SUMMARY FOR FB-CGS-CC SYSTEMS FOR ALTERNATIVE METHODS OF GAS TURBINE COOLING

	All Water Cooled	Prime Backup W/C Nozzle & S/C Buckets*	All Steam Cooled	All Air Cooled
G.T. Output (2 Units), MW	361.1	391.0	499.2	231.3
S.T. Output (1 Unit), MW	157.7	98.7	64.4	108.2
Aux. & B.O.P., MW	11.9	10.8	12.2	7.4
Total Plant Output, MW	504.2	478.9	551.4	332.1
Net Plant HR, Btu/kW-hr	8240	8704	9145	8780
Total Plant Thermal Efficiency % (HHV)	41.42	39.21	37.32	38.87

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*The Stage 3 bucket is uncooled. Cooling this bucket to attain a parts life of 83,000 hours reduces overall plant efficiency to 37.88%.

The consumption of both condensate and clarified quality water for the alternative systems is delineated in Table 3-6. The air-cooled reference design is shown to have minimum water requirements. The total of the chemical and first costs for the water required by the alternative system is shown in Table 3-7, also indicating a minimum for the all-air-cooled system closely followed by the reference water-cooled design.

3.3.8 Comparative Combined Cycle: "Product Line" STAG vs. HTTT System at 2600 °F With Water-Cooled Designs

An important question with respect to the development of the HTTT gas turbine and its associated combined cycle is the improvement in overall plant efficiency relative to the currently available STAG systems with a gas turbine firing temperature of 1985 °F and air-cooled technology. The performance of the General Electric Company's distillate-fueled STAG-400 plant is shown in lines 1 through 6, column 1, Table 3-8, and in column 2, performance of the advanced FB-CGS-CC system on a bus-bar to coalpile basis. In lines 7 through 16, column 2, the FB-CGS-CC performance is put on an equivalent basis with the STAG-400 in a manner previously described in Section 3.3.5, wherein the combined cycle is not charged with the thermal or mechanical losses associated with the fuel plant. Note that the gas turbines' output is credited with the power into the extracted process air (line 7) and the steam turbine output is credited with the power to the booster compressor, plus that equivalent to the process steam, (line 9). The net plant efficiency of the FB-CGS-CC system (line 15) is 11.6% better than the STAG-400. However, the true gain resulting from the advanced gas turbine system is actually approximately 3% greater than this because of the fact that the FB-CGS-CC system has been charged with the latent heat of the water vapor which is entrained in the low-Btu gas; the net effect is a loss of about 3% in the combined cycle efficiency. Consequently, the actual improvement in the combined cycle is about 14.5%.

Table 3-6

COMPARATIVE WATER CONSUMPTION FOR ALTERNATIVE COOLING SYSTEMS
2600 °F FIRING — ADVANCED FIXED-BED BENFIELD CLEANUP SYSTEM
(FLOWS ARE FOR THE FULL 2-G. TB. SYSTEM)

G. Tb. Cooling Type:	Water	Backup	Steam	Air
Cleanup System	18.2	18.2	21.7	12.8
HRSG Blowdown	2.6	2.8	4.4	1.9
Buckets & Nozzles	29.6	196.0	441.8	-
Gasifier Steam	20.	20.1	23.9	14.0
Gasifier Water Jacket	20.8	20.9	24.9	14.6
Saturation System	39.0	39.1	46.5	27.4
Σ Condensate Quality (pps)	130.2	297.1	563.2	70.7
Secondary Polishing	29.6	-	-	-
Coal Handling & Scrubbing	6.6	6.6	7.9	4.6
Main Cooling Tower	338.0	175.0	-	223.0
Cleanup System Cooling Tower	43.6	43.8	52.0	30.6
Σ Clarified (pps)	388.2	225.4	59.9	258.2
Total (pps)	518.4	522.5	623.1	328.9
Output (MW)	504.2	478.9	551.4	332.1
Gal/kW-hr	0.443	0.470	0.487	0.427

Table 3-7

COMPARATIVE WATER COSTS FOR FB-CGS-CC SYSTEMS WITH ALTERNATIVE COOLING SYSTEMS

G. Tb. Cooling Type:	Baseline Water	First Backup Water/Steam	Steam	Air
I. Water Requirements				
1. Condensate Quality (Gal/kW-hr)	0.111	0.267	0.440	0.092
2. Secondary Polishing (Gal/kW-hr)	0.025	-	-	-
3. Clarified Quality (Gal/kW-hr)	0.332	0.203	0.047	0.335
II. Costs (Mills/kW-hr)				
A. Chemical Costs				
1. Condensate Quality	0.083	0.200	0.330	0.069
2. Clarified	0.010	0.006	0.001	0.010
3. Secondary Polishing	0.004	-	-	-
ΣChemical Costs	0.097	0.206	0.331	0.079
B. First Costs				
1. Raw Water Through Demineralizer	0.023	0.056	0.093	0.019
2. Secondary Polishing	0.003	-	-	-
ΣFirst Costs	0.026	0.056	0.093	0.019
Total Costs (Mills/kW-hr)	0.123	0.262	0.424	0.098

Table 3-8

COMPARATIVE PERFORMANCE OF PRODUCT LINE AND HTTT (2600 °F) COMBINED CYCLES

	GE STAG 400 with MS-7001E Turbines	FB-CGS-CC 2600 °F, Water Cooled Benfield Cleanup
1. Gas Turbine Output (MW)	283.0 (4)*	361.1 (2)*
2. Steam Turbine Output (MW)	122.7	155.1
3. B.O.P. Aux. Power (MW)	6.1	11.9
4. Net Plant Output (MW)	399.6	504.2
5. Overall Plant η	42.20**	41.42[†]
6. Overall Plant H.R. (Btu/kWh)	8087.0**	8240.0[†]
7. Gas Turbine Power to Process Air (MW)	NA	32.1 (2 Gas Turbines)
8. Actual Gas Turbine Output (MW)	NA	393.2 (2)
9. Equivalent Steam Turbine Power to Boost Comp'r. and Process Steam (MW)	NA	17.7
10. Equivalent Steam Turbine Output (MW)	NA	172.8
11. Total Equivalent Output (MW)	405.7	566.0
12. B.O.P. Aux. Power (MW)	6.1	10.0
13. Net Plant Output (MW)	399.6	556.0
14. Net Plant η (HHV)	42.20**	47.08**
15. Net Plant η (LHV)	44.70**	50.14**
16. Net Plant H.R. (HHV) (Btu/kWh)	8037.0**	7249.0**

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*Number of Gas Turbines

**Fuel to Busbar Efficiency

†Coal Pile to Busbar Efficiency

Section 4

PLANT DESIGN CRITERIA AND GUIDELINES

GENERAL

Part 4.1 of this section includes those fundamental guidelines that are dictated by the customer's specific requirements with respect to where the plant is to be sited, how it will be used on his system, and his financial methods relative to evaluating costs and benefits as a basis for design decisions.

Part 4.2 also includes those design criteria and guidelines which indicate well-established and well-recognized design features which are known to be important in making the combined cycle plants economically and operationally attractive.

Part 4.3 considers those plant design criteria and guidelines which require cost-benefit tradeoff studies and include:

- Determination of the full plant capacity
- Selection of the type of low-temperature gas cleanup system
- Selection of the gasifier steam and air blast system
- Selection of the gasification system itself

4.1 SITE CHARACTERISTICS AND CUSTOMER REQUIREMENTS

4.1.1 Location

Middletown, U.S.A., with atmospheric conditions such that the average plant performance to be considered can be presented at the ISO conditions of -

- Sea Level
- Ambient Dry Bulb: 59 °F
- Relative Humidity: 60%

4.1.2 Range and Profile of Average Ambient Temperature

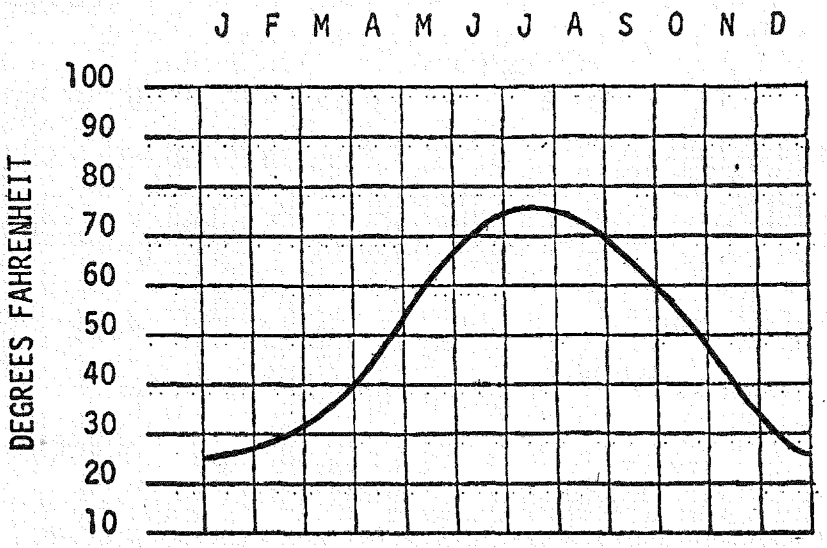

Figure 4-1. Profile of Average Ambient Temperatures

4.1.3 Maximum Range of Ambient Temperature -20 °F to 95 °F

4.1.4 Raw Water Specification--Mississippi River

Table 4-1

RAW WATER SPECIFICATIONS

	PPM		PPM		PPM
SiO_2	5.2	CO_2	0.0	Dissolved Solids	251.0
Fe	0.02	CHO_3	170.0	Alkalinity, as CaCO	151.0
Mn	0.18	SO_4	49.0	Hardness	184.0
Ca	45.0	Cl	10.0	pH, average	7.7
Mg	17.0	F	0.4	Turbidity	218.0
Na	10.0	NO_3	0.3	Color	20.0
K	1.6			Specific Conductance	410.0

4.1.5 Plant Life 30 years

4.1.6 Anticipated Loading Requirements

The plant will be designed for a nominal baseload requirement which, based on the usual plant life cycle, would demand baseload operation for the first 15 years, followed by midrange operation for the last 15 years.

4.1.7 Emissions

Emissions standards for NO_x and SO_2 are based on those which have been established for conventional coal-fired plants.

- Oxides of Nitrogen: 0.7 lbs/10^6 Btu at the coal pile
- Oxides of Sulfur: 1.2 lbs/10^6 Btu at the coal pile
- Carbon Monoxide: 90 ppmv at 15% oxygen (vol) in the gas turbine exhaust
- Visible Emissions: Limited to 10% opacity

4.1.8 Acoustics

- The noise level at 400 ft in any direction from the plant periphery must not exceed 57 dB.
- Those plant locations having noise levels that are expected to exceed 90 dB at one meter must be identified in order to permit the customer to comply with OSHA of 1970.

4.1.9 Economic Factors

- Capital costs - first quarter, '77, dollars
- Capital cost adders during construction:

  Escalation @ 6-1/2% per year
  Interest @ 10% per year

- Average fixed charge rate: 18% per operating year
- Plant load factor: 65%
- Period of realization: 40 months (Requisition to commercial operation)

4.2 DESIGN CRITERIA

4.2.1 Gas Turbine Design

A major objective is to carry out the design of the gas turbine subsystem and gas turbine system so that those characteristics of current gas turbines which are known to result in low-cost energy and excellent operation characteristics and flexibility are retained. These include:

- Modularized, highly packaged, factory-assembled, skid-mounted construction, with associated outdoor lagging to permit slab-type installation.
- Enclosures for gas turbine accessory systems where necessary to provide weather, thermal, and acoustic insulation; these will be readily removable, in sections, for ease of maintenance.
- An automatic control system that will permit the machine to be started, synchronized, and loaded on No. 2 distillate, and subsequently transferred to coal-derived fuel (low-Btu gas or liquid). In addition to providing the protection currently required by gas turbines operating in combined cycle arrangements, the system will also provide protection during contingencies arising from the new gas turbine/fuel plant interface requirements.

Criteria for gas turbine reliability and availability will be consistent with that which has been demonstrated for General Electric Company's mature heavy-duty gas turbines and includes the following:

- Starting reliability (SR) on No. 2 distillate oil:

$$SR = \frac{\text{Successful Starts}}{\text{Attempts to Start}} = 0.99$$

- Forced outage rate (FOR) for baseload operation:

$$FOR = \frac{FOH}{FOH + SH} = 0.0075$$

Where: FOH = Forced Outage Hours
SH = Service Hours

- Availability (AV) for baseload operation:

$$AV = \frac{PH - PDT - UDT}{PH} = 0.965$$

Where: PH = Period Hours
PDT = Planned Downtime Hours
UDT = Unplanned Downtime Hours

4.2.2 Plant Heat Rejection System

A common mechanical draft evaporative cooling tower heat rejection system will furnish the heat rejection requirements for the entire plant. The design basis will be an atmospheric condition that is not exceeded more than 5% of the time, as follows:

Dry Bulb T = 95 °F
Wet Bulb T = 76 °F
Approach = 10 °F
Range = 17.7 °F

Based on these design data, and with a 5 °F approach in the main condenser, the main steam turbine will operate at 2.5" Hgabs.

4.2.3 Integrated Plant Control

An overall integrated plant control system is a major requirement for these combined cycle systems. The system must necessarily have the capability of automatic startup on No. 2 distillate fuel, subsequent transfer to low-Btu gas when available, operation at load and fail-safe operation when required during contingencies.

4.2.4 Steam Plant Design

- The steam turbine generator and its associated accessories and balance of plant items, plus the steam-turbine-driven booster compressor sets will be located in a steam turbine building.

- The heat recovery steam generators will be designed for and installed outdoors.

4.2.5 Fuel Plant Design

- To the extent possible and in keeping with good design practices, the fuels plant will be designed for and installed outdoors.

- With the exception of local control and instrument panels, which may be required, the fuel plant's control, operating, and supervisory panels and equipment will be located in and operated from the plant central control room.

- The basic process functional specifications for the fuels plant, with respect to the steam and air blast to the gasifiers, will be set to optimize the cold gas efficiency.

4.2.6 Fuel Selection and Low-Btu Coal Gas Specifications

The Illinois No. 6 coal which is used as the basis for the overall plant designs has a composition and characteristics as shown in Table 4-2. This is the same analysis as that used in the ECAS study.*

Table 4-2

COAL SPECIFICATIONS

Proximate Analysis		Ultimate Analysis	
Volatiles	36.70% Wt	C	59.60% Wt
Fixed Carbon	40.70	H	5.90
H_2O	13.00	O	20.00
Ash	9.60	N	1.00
TOTAL	100.00	S	3.90
		Ash	9.60
		TOTAL	100.00

LHV = 10234 Btu/lb
HHV = 10788 Btu/lb

The composition of the clean low-Btu gas is a function of the type of gasifier, the temperature of the steam and air blast, the gasifier pressure, and the gas cleanup system. Based on using the Benfield and alkazid gas cleanup systems for the fixed and entrained-bed gasifiers, respectively, and with the pressure and temperature conditions as shown on the system schematic (Figures 3-1 and 3-6, respectively), the composition of the clean gas available to the gas turbine is as indicated in Table 4-3.

Note that the gas from the fixed-bed system is characterized by ethylene (C_2H_4), ethane (C_2H_6), naphtha, and phenols, in addition to the other constituents that are also in the gas from the entrained-bed fuel system. These components are generated from the volatile portion of the coal and are not further reduced or cracked because of the relatively low off-gas temperature which is characteristic of the fixed-bed system.

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*Executed by General Electric Company under NASA Contract No. NAS 3-1947

Table 4-3

FUEL COMPOSITION

Fixed-Bed Gasifier

Constituent	Wt %	MOL %
CO_2	3.90	1.98
CO	27.0	21.50
H_2S	0.09	0.06
COS	0.077	0.03
C_2H_4	0.23	0.18
C_2H_6	0.36	0.27
CH_4	2.35	3.28
H_2	1.10	12.28
N_2	39.70	31.61
NH_3	.027	0.04
NAPHTHA	2.11	0.32
PHENOL	.22	0.05
H_2O	22.93	28.40
	100.00	100 %

MW = 22.32 lb/MOL

Lower Heating Value =(2739 Btu/lb
(161.73 Btu/SCF

Higher Heating Value =(2936 Btu/lb
(173.36 Btu/SCF

Entrained-Bed Gasifier

Constituent	Wt%	MOL %
H_2	1.16	14.19
CO	32.11	28.22
CO_2	6.90	3.86
CH_4	2.24	3.44
N_2	56.25	49.42
A	1.02	.63
H_2S	.03	.02
COS	.17	.07
NH_3	< 50 PPMV	< 50 PPMV
H_2O	.11	.15
	100.	100 %

MS = 24.70 lb/MOL

Lower Heating Value = (2519 Btu/lb
(164.6 Btu/SCF

Higher Heating Value = (2682 Btu/lb
(175.25 Btu/SCF

The relatively high temperature and high percentage of water vapor is another distinguishing feature of the fixed-bed fuel system. Subsequent to water-scrubbing the raw gas to a saturated condition at about 320 °F, the gas is further cooled to the temperature required for cleanup in the Benfield cleanup system. This is done regeneratively in a resaturator, so that as much of the latent heat and sensible heat as possible is returned. Reheating is also required for the reentrainment of the condensed light oils and phenols.

The amount of ammonia is relatively low because of the relatively low steam-to-air ratio utilized by the advanced fixed-bed type of gasification system. The total NO_x resulting from the combustion of the ammonia plus the "thermal" NO_x is less than 0.7 lb per million Btu at the coal pile; the relatively high proportion of water vapor in the low-Btu gas acts to suppress the formation of "thermal" NO_x.

Contaminant Specifications

With metal temperatures below 1000 °F, the tolerance of the nozzles and buckets is much greater than the maximum level that could be expected with low-Btu gas, even if there were to be a substantial reentrainment of ash at the time of entraining the light oils and phenols in the saturator.

4.3 DESIGN CRITERIA BASED ON PLANT ANALYSIS AND COST BENEFIT TRADE-OFF STUDIES

4.3.1 Selection of Fuels Plant Size

The high cost of the fuels plant makes it mandatory to select a plant that meets the needs of the intended site and service. The increased power level at lower ambient temperatures is a unique characteristic of the combined cycle that should be utilized, but only as the total associated costs and benefits are properly balanced.

To determine the preferred fuel plant size, a cost-benefit study was carried out, wherein three fixed-bed CGS-CC plants were configured with fuel plants having capacities for full-load plant operation down to temperatures of 26 °F, 40 °F and 59 °F. Based on the profile of average ambient temperatures (Figure 4-1) and the performance characteristics of each plant as a function of ambient temperature (Figure 4-2), the total yearly generation of energy (kW-hrs) for each plant was determined. The evaluation of the three plants is summarized on Table 4-4, wherein the average annual first costs and energy generation (kW-hrs) and the associated unit energy costs (MILS/kW-hr) are indicated. The unit energy cost and the relative gasification plant size are shown on Figure 4-3 as a function of the minimum ambient temperature at which the fuel plant can carry full power.

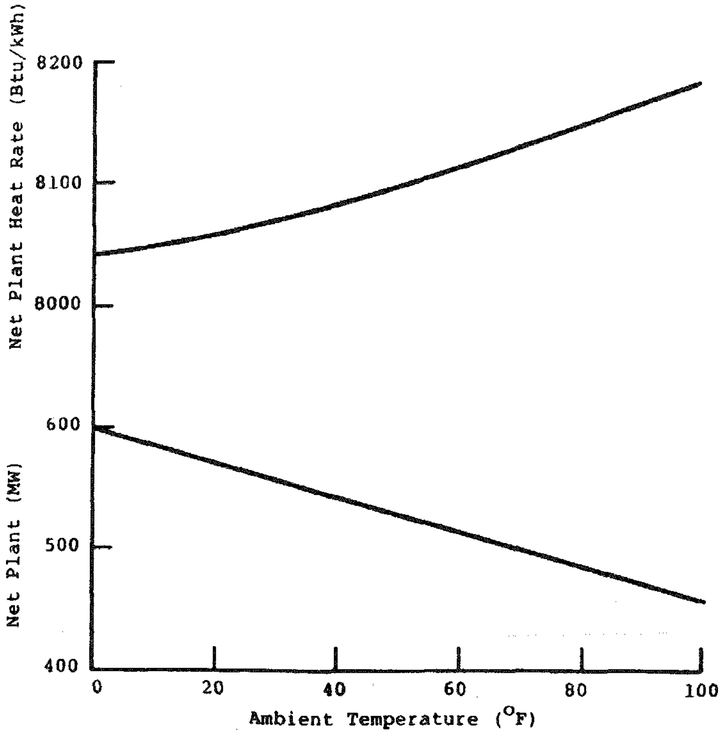

Figure 4-2. Fixed-Bed CGS-CC Plant Operating Characteristics vs Ambient Temperature

Table 4-4

EFFECT OF FUEL PLANT SIZE ON TOTAL ENERGY COST

Nominal Design T (°F)	26	40	59
kW-hrs per Year	3093.3×10^6	3052.4×10^6	2945×10^6
Estimated Costs @ Completion of Installation (Including Escalation and Interest During Construction) ($)	354.15×10^6	346.86×10^6	334.5×10^6
Annual First Costs @ 18% Avg. Cap. Rate ($)	63.75×10^6	62.43×10^6	60.21×10^6
Annual Fuel Cost ($)	25.52×10^6	25.25×10^6	24.64×10^6
Total Annual Cost ($)	89.27×10^6	87.68×10^6	84.85×10^6
Energy Cost (M/kW-hr)	28.86	28.72	28.81

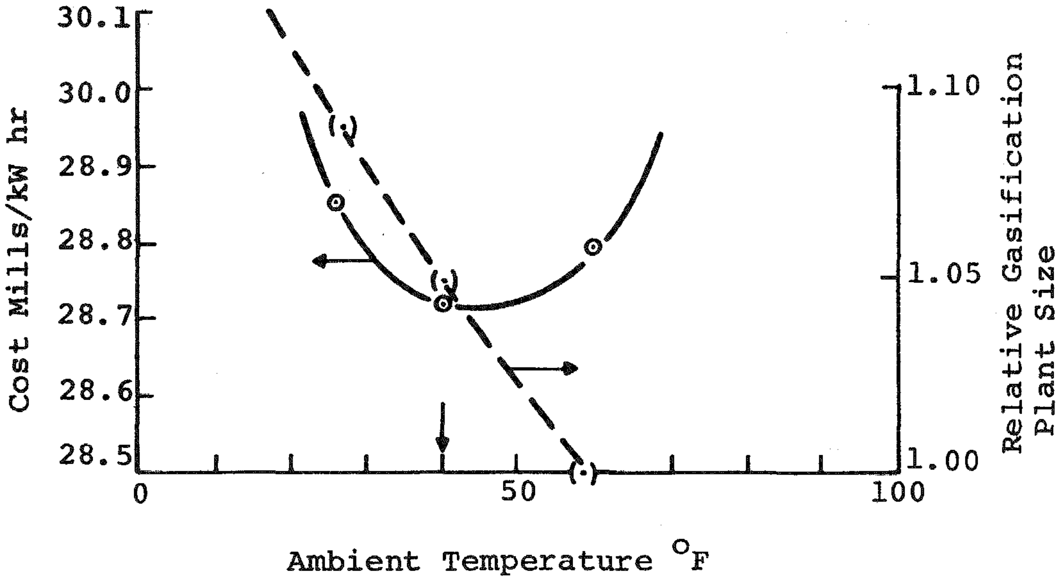

Figure 4-3. Energy Costs and Relative Size of Fixed-Bed Gasification System vs Design Ambient Temperature

Based on this study, the nominal fuel plant capacity is that required to carry full power operation at 40 °F; from Figure 4-3, this is 5% greater than that required for operation at 59 °F, as shown on Figure 3-1. Although the gasifier design has been established so that 12 vessels can furnish the requirements at 59 °F, the 12 gasifiers can also accommodate the 40 °F ambient temperature condition. The overall plant performance guarantee has been established with 14 vessels in order to provide adequate redundancy for forced and planned outages. Each gasifier is estimated to deliver 31.8 lb/s of quenched raw gas at 59 °F.

4.3.2 Selection of the Gas Cleanup System

In order to make the selection of a preferred coal gasification process as meaningful as possible, the selection of the preferred gas cleanup system was considered on an individual basis for both the fixed-bed and entrained-bed CGS-CC plants.

4.3.2.1 Selection of the Preferred Low-Btu Gas Cleanup System for the Fixed-Bed Gasification System. Working in conjunction with C.F. Braun and Co. and the General Electric Company Research and Development Center, investigations of three low-temperature, low-Btu gas cleanup systems resulted in the selection of the Benfield hot potassium carbonate system as a basis for overall system definition, and also as a reasonable basis for investigating overall plant operation and control. In this sense the Benfield is a "preferred" selection that does not necessarily represent the optimum system. Indeed, the "optimum" system may well vary with several factors that were not considered in this study.

The candidate systems which were considered included the Alkazid and the Selexol, in addition to the Benfield. A raw gas specification was developed on the basis of the General Electric Company's advanced fixed-bed gasification system, making use of data regarding particulates and tar derived from ERDA's R&D Report No. 105, Trials of American Coals in a Lurgi Gasifier at Westfield, Scotland.

The three major subsystems in each of the gas cleanup systems studied are: the raw gas quench, the acid gas removal, and the clean gas saturation, as indicated on Figure 3-3. Neither carbonyl sulfide (COS) nor NH_3 removal is necessary to achieve the levels of emission required by the expected regulations. A 90% removal efficiency and a 95% sulfur removal efficiency in the Claus plant is required in the gas cleanup plant.

Each of the candidate systems was analyzed with respect to overall plant thermodynamic performance, operating costs, first costs, adequacy of design information, and installation experience. Table 4-5 delineates the important factors and results of the comparative analysis of the three systems.

Table 4-5

ECONOMIC EVALUATION GAS CLEANUP SYSTEM

	Benfield	Selexol	Alkazid
Plant Performance			
Btu/kW-hr	8111	8166	8139
Annual Chemical Costs ($)	12,000	60,000	710,000*
Equivalent Chemical Costs ($/kW)	.1	0.9	7.1
Power Plant Costs (without GCUS)			
$/kW	700	697	696
Cleanup System Costs			
$/kW	92	124	89
Evaluation			
Δ $/kW-CUS	Base	+32	-3
Δ $/kW Chemical Cost	Base	+0.8	+7
Δ $/kW-BOP	Base	-3	-4
Δ $/kW Fuel Costs	Base	+1.8	+0.9
ΣΔ $/kW Net	Base	+31.6	+0.9

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*Reflects irreversible process in absorber

With respect to cleanup system installed costs, the Selexol system was found significantly higher, whereas the Benfield and Alkazid system costs were quite close. However, the chemical costs for the Alkazid system are significantly higher than for the Benfield, reflecting the irreversible absorption of feed gas phenols by the Alkazid DIK solution. Limiting the concentration of the absorbed phenols in the solution requires significant blowdown and, consequently, high chemical costs.

The Benfield system, on the other hand, employs a relatively simple, inexpensive chemical solution that is readily available. The importance of chemical operating losses is relatively minor with the Benfield process.

The evaluation is done on the basis of evaluated deltas (Δ's) relative to a CGS-CC plant utilizing the Benfield system. The fuel cost delta is based on the difference in the indicated heat rates, 65% load factor, $1 per million Btu coal costs, and an 18% average capitalization rate. Realistically, at this time, the comparative evaluation indicates only a small economic incentive for the Benfield system.

Operating experience, although somewhat limited, has also been investigated.

A Selexol acid gas removal unit has been built in Homer City, Pennsylvania, to process raw gas to be produced in the Bituminous Coal Research (BCR) Bi-Gas Process (BCR BI-GAS) coal gasification pilot plant. The plant startup was scheduled for late '76, but has been delayed. It has been reported that the Alkazid DIK process has been used to desulfurize coke-oven gas in Europe.

A Benfield hot potassium carbonate acid gas removal unit is in operation with the Lurgi coal gasifiers in Westfield, Scotland. No significant problems have been reported. A Benfield hot potassium carbonate acid gas removal unit has been built for the Synthane coal gasification pilot plant in Bruceton, Pennsylvania. The plant is now in the process of starting up.

With respect to experience and with the goal of technology readiness within six years, the hot potassium acid gas removal unit is considered to have an edge. It is emphasized again, however, that the selection of the Benfield system in no way constitutes General Electric Company's advocacy of the system.

4.3.2.2 Selection of the Preferred Low-Btu Gas Cleanup System for the Entrained-Bed Gasification System. Working in conjunction with Foster Wheeler Energy Corporation, investigations of the Benfield, Alkazid, and Selexol low-temperature gas cleanup systems have resulted in the selection of the Alkazid system for use with the entrained-bed gasification system.

There are three major differences in the raw, low-Btu gas from the entrained-bed gasifier relative to that from the fixed-bed gasifier. First, there are no phenols which, as pointed out in Section 4.3.2.1, are irreversibly absorbed in the Alkazid DIK solution. Second, there is a relatively high level of ammonia, which requires a separate removal system. Third, the off-gas temperature is about 1700 °F versus about 1040 °F for the fixed-bed system.

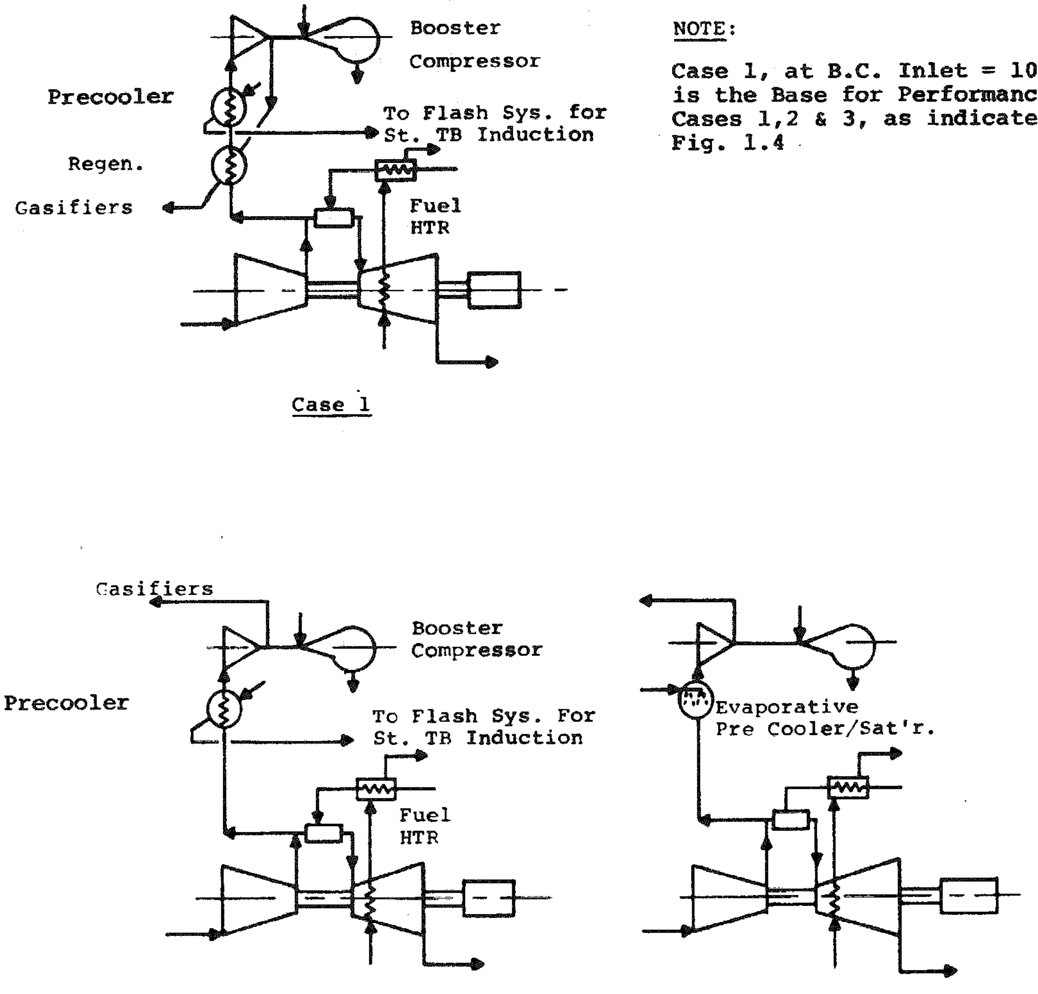
The lack of phenols is the major difference that affects the relative evaluation between the Alkazid and the Benfield processes. Referring to the equivalent chemical costs shown in Table 3-6, it is seen that eliminating the high costs associated with the phenol absorption would result in a net evaluation (bottom line) of about $6.3/kW in favor of the Alkazid system.

4.3.3 Selection of Gasifier Steam and Air Blast System

Several arrangements for furnishing process steam and air to the gasifier have been considered; three of these, Cases 1, 2, and 3, are shown on Figure 4-4, with Case 2 being "preferred" at this time. As indicated, and also as shown on Figure 3-1, gasifier process air is extracted from the gas turbine and intercooled only to a temperature that results in 700 °F booster compressor discharge temperature to the gasifier; this is considered a reasonable maximum temperature limitation for available equipment. A single shell and tube precooler uses 225 °F cooling water from the deaerator and discharges 600 °F water for use in the multistage flash system. With a precooler Inlet Temperature Difference (ITD) of 50 °F, the minimum air discharge temperature is 275 °F, unless another heater exchanger which rejects the incremental heat to circulating water is used. The performance characteristics of Case 2 as a function of the temperature of the air to the booster compressor are shown on Figure 4-5; note that the performance is referenced to that for Case 1 operating with 100 °F to the booster compressor. For Case 2, the overall plant heat rate improves as the temperature to the booster compressor increases, and, correspondingly, the heat utilized in the flash system at relatively low efficiency is reduced. Below 275 °F, the rate of change of performance is greater because of the total loss of the heat below 275 °F to circulating water.

Note that the best plant heat rate is obtained by using a 500 °F air temperature to the booster compressor and, thereby, operating at the maximum acceptable compressor discharge temperature, 700 °F.

Case 1, Figure 4-4, utilizes both shell and tube and regenerative air cooling and reheating, thereby inherently reducing the heat utilized in the flash system. At higher booster compressor inlet temperatures, the regenerative heat transfer is reduced, and the heat to the flash system, recovered at lower efficiency, increases; note the trend to poorer plant heat rates (Figure 4-5). Note that the best plant heat rate is obtained at the unique point



Case 1

Case 2

Case 3

NOTE:

Case 1, at B.C. Inlet = 100 °F is the Base for Performance of Cases 1,2 & 3, as indicated on Fig. 1.4

Figure 4-4. Arrangements of Air/Steam Blast Systems

where regenerative heating is maximized without the rejection of heat to circulating water, i.e., at 275 °F air temperature to the booster compressor. At this point the overall plant performance is about 0.25% better than Case 2.

Case 3, Figure 4-4, utilizes an evaporative precooler wherein a unique air temperature to the booster compressor is inferred. The overall plant heat rate is somewhat better than that of Case 2 at this temperature, reflecting the net effect of eliminating the loss resulting from extracting process steam and increasing the power required for the booster compressor.

The selection of the Case 2 approach, rather than Case 1, has been made on the basis of what is considered to be a simpler and probably less expensive system (fewer and less complex heat exchangers), but at some small (∿0.25%) loss in overall performance.

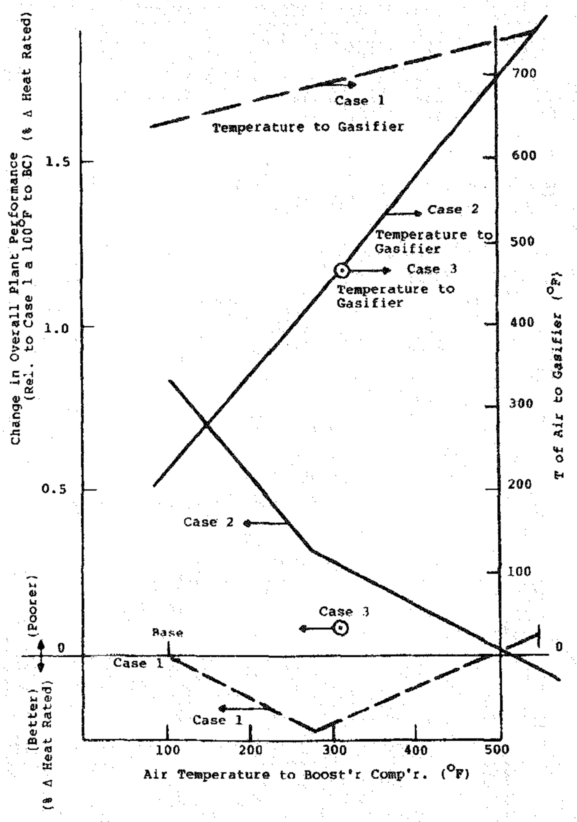


Figure 4-5. Comparison of Alternative Air/Steam Blast Systems

4.3.4 Selection of Gasification System

4.3.4.1 Introduction. As part of Task 2 of the Phase I effort, the total energy costs, mils/kW-hr, are developed for both the fixed-bed and the entrained-bed CGS-CC systems. However, since both systems are to some extent developmental, subjective judgments or appraisals with respect to important developmental areas must also be considered. Consequently, in Table 4-6, ratings of 1, 2, or 3 are assigned to each of nine areas. Note that when both systems are considered about equal with respect to a specific area or feature, each is credited with a (1). When a difference is considered to exist, only that system which is better receives a ranking; a (2) is awarded if slightly better, and a (3) if outstanding on a comparative basis; the ratings, obviously, are not on an absolute basis.

4.3.4.2 Efficiency. In Section 3.3.4 two entrained-bed CGS-CC systems were discussed: Case B1, wherein all of the high-temperature heat in the raw product gas is recovered in the WHB, is about 0.9% (0.36 points) poorer than the FB-CGS-CC; and Case B2, wherein a regenerative gas-to-gas heat exchanger enables a significant proportion of this heat to be used as primary heat to the combustor, with an overall plant efficiency that is 1.8%

Table 4-6

GASIFIER EVALUATION CHARACTERISTICS & FACTORS

	ADVANCED FIXED-BED		ENTRAINED-BED	
1. Efficiency	Marginally Better In The Near Term	(1)	Good Long Range Potential	(1)
2. Fines Ability	Yes - (With Extruder Development)		Yes	(2)
3. Caking Coal Ability	Yes - (With Development Of Gasifier Internals)		Yes	(2)
4. Char Recycle	N.A.	(3)	Yes - (With Development Program)	(-)
5. Tar Generation	Yes - (Capability of Recycling with Fines, & Cracking)		None	(3)
6. Steam/Air Ratio	Low (0.2)	(1)	Low (0.07)	(1)
7. Ammonia Generation	Low - (removal not necessary)	(2)	High (requires removal)	(-)
8. Control	o Constant Pressure With Potential Of Variable Pressure	(3)	o Variable Pressure Necessary For Proper Entrainment	(-)
	o Rapid Loading: 0-100% In 30 Minutes	(1)	o Rapid Loading	(1)
	o Can Be Satisfactorily Tripped W/O Slag Problems	(3)	o Potential Slagging Problems on Trip	(-)
	o Single Boiler Control	(2)	o WHB & HRSG Control Required	(-)
9. Experience	Many Operating Units	(3)		(-)
10. Cost (A Function Of Gas Tb. Pwr: Steam Turbine Power)	o Gas Pwr: St. Pwr = 70:30 o Estimated Plant Costs $791/kW	(2)	o Gas Pwr: St. Pwr: 62"38 o Estimated Plant Costs $828/kW	(-)
		21		10

SUMMARY OF EVALUATION FACTORS

Value Of Factors

1 = Even Rating

2 = Somewhat Better

3 = Outstanding

(0.75 points) better than Case A1. Case B1 is considered to be a preferred entrained-bed, near-term system because of the less-complex raw gas cooling system. However, in spite of the indicated difference in overall plant efficiency, both the advanced fixed-bed and entrained-bed gasification systems have been given "1" ratings; this reflects the tolerance that must be considered with respect to any overall plant efficiencies at this time.

4.3.4.3 Ability to Use Fines and Caking Coal. Areas 2 and 3, which refer to the major development areas of the advanced fixed-bed gasifier, are considered to favor the entrained-bed system, but only with a "somewhat better" (2) rating.

4.3.4.4 Ability to Recycle Char. This is a unique requirement for the entrained-bed gasification system and generally recognized as its major developmental area. Clearly, the advanced fixed-bed system warrants a (3) rating here.

4.3.4.5 Tar Generation. The complete absence of tar generation, in the case of the entrained-bed CGS-CC system, is considered an "outstanding" (3) advantage for the entrained-bed system, in spite of the fact that the advanced fixed-bed plant does use the tar satisfactorily. The tars which are formed in the fixed-bed system are partially recycled to the gasifier as part of the fine extrudate, and partially reinjected and revaporized as part of a heated, clean-fuel-gas system.

4.3.4.6 Steam/Air Ratio. The advanced fixed-bed system operates with about one-third of the steam/air ratio that is typical of state-of-the-art fixed-bed systems. This is conducive to improved gasification efficiencies, as well as the inherent improvement associated with the greater steam available for power generation.

It should be emphasized that, although state-of-the-art fixed-bed gasifiers operate at higher steam/air ratios, successful operation at the lower ratios has been well demonstrated by the Bureau of Mines at Morgantown and also by the General Electric Company's Research and Development Center.

4.3.4.7 Ammonia Generation. The relatively low level of ammonia generated in the fixed-bed gasifier, which eliminates the necessity of a separate removal facility, warrants the "somewhat better" (2) rating. In event the regulations with respect to NO_x were to be significantly reduced, the gasification systems would be considered to be equally burdened with similar ammonia removal facilities.

4.3.4.8 Control. The operating pressure required for the entrained-bed system is a function of the drag characteristics that will permit entrainment of the pulverized coal to the extent that complete devolatilization occurs only in the upper portion of the gasifier vessel. As the plant load is reduced, the required pressure decreases at a faster rate than is permissible at the gas turbine combustors, assuming that there is no throttling. Consequently, in order to achieve turndown, a higher pressure and throttling control are required at the full-flow operating point, thereby introducing higher equipment costs and, in some degree, increased control problems.

The advanced fixed-bed system can satisfactorily turn down at constant pressure or, if desirable, at a variable pressure rate, which would eliminate significant throttling at any load point. This characteristic permits the gasification system to be tripped and, subsequently, held in a hot standby condition at any pressure, and at relatively low reaction rates. This potential flexibility of control is considered to be relatively "outstanding" (3).

During normal operation, the lower portion of the entrained-bed system is in a slagging condition. Therefore, in a contingency situation of any kind that requires rapid shutdown, or trip, provisions must be made to keep the vessel from freezing up with slag.

The advanced fixed-bed system can be tripped without a slag freeze-up problem because it operates at temperatures below a slagging condition. This potential to withstand trips in a relatively trouble-free manner is also considered to be relatively "outstanding" (3).

In the entrained-bed system with a low-temperature gas cleanup system (Figure 3-6), a waste heat boiler is required to recover the high-level heat efficiently. In the fixed-bed system the available energy in the gas can be utilized wholly by the gas turbine, and steam generation occurs totally in the HRSG. The relative simplicity of the latter steam system earns it a "somewhat better" rating (2).

4.3.4.9 Experience. With respect to experience, the fixed-bed gasification system is relatively "outstanding" (3), not only because of the large, oxygen-blown, pressurized gasifiers that are operating commercially at relatively high steam to oxygen ratios, but also because of the smaller, air-blow pilot plants which have been, and are, operating successfully with low steam to air ratios at the Morgantown Energy Research Center and at the General Electric Company Research and Development Center. When the entrained-bed system goes into the pilot plant stage and operates successfully, this advantage will disappear. However, based on a consideration of technology readiness in six years, the relative experience of the fixed-bed system is an important factor.

4.3.4.10 Cost. Cost, like efficiency, can be expressed in absolute $/kW, and values have been developed for both the advanced FB-CGS-CC and the EB-CGS-CC systems which show lower costs for the fixed-bed system. In addition, there are characteristics of the two systems which indicate that this may be a basic generic difference. Specifically, the ratios of gas-to-steam turbine power for the FB and EB systems are 70%:30% and 62%:38%, respectively, which is a factor in lower FB-CGS-CC systems resulting from the inherently lower cost of gas turbine power. It is recognized, of course, that fewer entrained-bed gasification vessels are required (2 vs. 12), although they are considerably larger. The specific overall plant costs developed during Phase 1 for the FB and EB systems are $791/kW and $828/kW, respectively, substantiating the trend indicated by the ratio of gas to steam turbine power. A "somewhat better" (2) award, reflecting these factors, has been assigned to the fixed-bed system.

4.3.4.11 Summary. The summation of the evaluation factors as indicated in Table 4-6 is seen to favor the advanced fixed-bed system by 21 to 10, and has been a significant evaluation in supporting the use of the advanced fixed-bed system as a source of low-Btu coal gas for integrated CGS-CC systems with the best potential for technology readiness in 1982 (within 6 years).

Section 5

SYSTEMS, SERVICES, AND FACILITIES

The systems and equipment listed below are organized into the six major systems identified in the overall plant description. It is intended to review major equipment items only, but some areas may be more detailed than others.

5.1 FUEL SYSTEM

5.1.1 Principal Equipment for Coal Handling, Drying, and Storage

Item	Tag Number[1]	Description	Quantity
5.1.1.1	111-CO-1-1	Yard Belt Conveyor: 60" belt, 3000 tph capacity, 380 ft long, 90 ft lift, 400 hp drive	1
5.1.1.2	111-CO-1-2	Active Pile Stacking Conveyor: 60" belt, 3000 tph capacity, 780 ft long, 40 ft lift, 300 hp drive	1
5.1.1.3	111-CO-1-3	Reclaim Belt Conveyor: 48" belt, 600 tph capacity, 740 ft long, horizontal, 50 hp drive	1
5.1.1.4	111-CO-1-4	Primary Screen Feed Belt Conveyor: 48" belt, 600 tph capacity, 240 ft long, 60 ft lift, 75 hp drive	1
5.1.1.5	111-CO-1-5	Auxiliary Reclaim Conveyor: 48" belt, 600 tph capacity, 400 ft long, 90 ft lift, 100 hp drive	1
5.1.1.6	111-CO-1-6	Sized Coal Collecting Conveyor: 48" belt, 600 tph capacity, 400 ft long, 100 ft lift, 100 hp drive	1

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[1] Reference: C.F. Braun Dwg. 5102-100-111-XD-1 Rev. 3
C.F. Braun Dwg. 5102-100-111-XD-2 Rev. 4
(See Section 5 Appendix)

Item	Tag Number	Description	Quantity
5.1.1.7	111-CO-1-7	Lump Coal Collecting Conveyor: 48" belt, 450 tph capacity, 80 ft long, 15 ft lift, 20 hp drive	1
5.1.1.8	111-CO-1-8	Undersize Coal Dryer Feed Belt Conveyor: 30" belt, 140 tph capacity, 360 ft long, 90 ft lift, 30 hp drive	1
5.1.1.9	111-CO-1(2)-9	Lump Coal Storage Bin Feed Conveyor: 36" belt, 225 tph capacity, 700 ft long, 175 ft lift, 75 hp drive	2
5.1.1.10	111-CO-1(2)-10	Dried Coal Belt Conveyor: 24" belt, 40 tph capacity, 650 ft long, 160 ft lift, 20 hp drive	2
5.1.1.11	111-DC-1-1	Dust Suppression System for all the areas from Rotary Car Dumper through Primary Crusher	1
5.1.1.12	111-DC-1-2	Dust Collector System for screening and drying areas (bag house-type)	1
5.1.1.13	111-DC-1(2)-3	Flue Gas Scrubbers for dryers: Venturi Wet-Type	2
5.1.1.14	111-DC-1-4	Dust Collector System for gasifier storage bins (bag house-type)	1
5.1.1.15	111-G-1-1	Primary Crusher (roller-type): 60 tph capacity, 20 hp drive	1
5.1.1.16	111-G-1(2)-2	Dried Coal Crusher (roller-type): 40 tph capacity, 20 hp drive	2
5.1.1.17	111-SC-1-1	Primary Screen (fixed-type): 2" opening, 5' x 10' size	1
5.1.1.18	111-SC-1-2A,B	Secondary Screen (vibrating-type): 1/2" opening, 5' x 12' size, 15 hp drive	2
5.1.1.19	111-V-1-1	Auxiliary Reclaim Bin: 150 ton capacity	1

Item	Tag Number	Description	Quantity
5.1.1.20	111-V-1-2	Primary Crusher Feed Bin: 20 ton capacity	1
5.1.1.21	111-V-1-3	Sized Coal Bin: 100 ton capacity	1
5.1.1.22	111-V-1-4	Intermediate Storage Bin: 1600 ton capacity	1
5.1.1.23	111-V-1(2)-5	Gasifier Overhead Lump Coal Storage Bin: 730 ton capacity	2
5.1.1.24	111-V-1(2)-6	Undersize Coal Storage Bin: 290 ton capacity	2
5.1.1.25	111-V-1(2)-7	Gasifier Overhead Fine Coal Storage Bin: 220 ton capacity	2
5.1.1.26	111-W-1-1	Belt Scale (for 60" wide yard conveyor): 3000 tph capacity	1
5.1.1.27	111-X-1-1	Rotary Car Dumper (package unit): 3000 tph capacity, capable of handling 100 ton cars in unit trains	1
5.1.1.28	111-X-1-2A,B	Rotary Plow Reclaimer: 600 tph capacity (one spare)	2
5.1.1.29	111-X-1-3A,B	Frozen Coal Cracker (under Rotary Car Dumper bin): 1500 tph capacity, 150 hp drive	2
5.1.1.30	111-X-1-4A,B	Frozen Coal Cracker (under Auxiliary Reclaim Bin): 300 tph capacity, 60 hp drive	2
5.1.1.31	111-X-1(2)-6	Fluid Bed Dryer (package unit): capacity to dry 40 tph wet coal with 13% to 3% moisture	2
5.1.1.32	111-X-1-7	Sampling System (package unit)	1
5.1.1.33	111-X-1-8	Caterpillar D-9 bulldozer with 24 ft pusher blade	1
5.1.1.34	111-X-1-11	12,000 ft of railroad track	

Item	Tag Number	Description	Quantity
5.1.1.35	111-X-1-14	Sprinkler system and yard hydrants for fire protection	
5.1.1.36	111-X-1-18	Railcar Thaw Shed: 20' wide x 500' long x 20' high	

5.1.2 Fuel Conversion

5.1.2.1 Coal Gasification and Quenching

Item	Description	Quantity
	Gasifiers	
5.1.2.1.1	Coal Gasifiers: main vessel, coal augers, bed stirrer, grate assemblies, coal lockhoppers, ash lockhoppers, and associated valves	14
	Lump Coal System	
5.1.2.1.2	Lump Coal Surge Bin	16
5.1.2.1.3	Coal Feeder (from surge bins to individual lockhoppers)	28
5.1.2.1.4	Lump Coal Bin Feeder (from lump coal distribution conveyors)	16
5.1.2.1.5	Lump Coal Conveyor System	2
5.1.2.1.6	Lump Coal Weigh Feeder	2
5.1.2.1.7	Lump Coal Elevator	2
	Fines Coal System	
5.1.2.1.8	10" Coal Extruder	14
5.1.2.1.9	Extrudate Mixer	14
5.1.2.1.10	Fines Bin	14
5.1.2.1.11	Fines Weigh Feeder	14
5.1.2.1.12	Tar Weigh Feeder	14
5.1.2.1.13	Fines Coals Conveyor	2
5.1.2.1.14	Fines Coal Feeder	2
5.1.2.1.15	Fines Coal Elevator	2

Item	Description	Quantity
	Ash	
5.1.2.1.16	Ash Lockhopper Discharge Mechanisms	14
5.1.2.1.17	Ash Conveyor and Loading Platform	1
	Quench	
5.1.2.1.18	Raw Gas Quench Vessels	14
5.1.2.1.19	Booster Compressor	2
5.1.2.1.20	Booster Compressor Driver	2
5.1.2.1.21	Booster Compressor Precooler	2
	Controls	
5.1.2.1.22	Control Valves (per gasifier): air blast control (1), steam blast control (2), steam jacket pressure (1), feedwater (1), gas flare (1), quench water (1), quench blowdown (1)	112
5.1.2.1.23	Remote On-Off Valves	112
	Instrumentation (for)	
5.1.2.1.24	Gamma-Type Level Detector	28
5.1.2.1.25	Level Detector	156
5.1.2.1.26	Thermocouple	280
5.1.2.1.27	Pressure Transducer	140
5.1.2.1.28	Measurement Orifice	56
5.1.2.1.29	Torque Measurements	84
5.1.2.1.30	Gas Analyzer	5
5.1.2.1.31	Boost Compressor (steam-driven)	2
5.1.2.1.32	B.C. Precooler	2

5.1.2.2 Heavy Tar Removal and Recycle[2]

5.1.2.2.1	Particle Agglomerator
5.1.2.2.2	Venturi Scrubber
5.1.2.2.3	Gas Liquid Separator

[2] Reference: C.F. Braun Dwg. 5102-100-113-XD-1 (See Appendix)

Item	Description
5.1.2.2.4	Scrubber Water Accumulator
5.1.2.2.5	Tar/Water Separator
5.1.2.2.6	Scrubber Water Circulation Pump
5.1.2.2.7	Recovered Water Return Pump

5.1.3 Fuel (Scrubbed Gas) Processing[3]

5.1.3.1 Benfield Low-Temperature Gas Cleanup System

5.1.3.1.1	Demineralized Water/Process Gas Exchanger
5.1.3.1.2	Demineralized Water Feed Pump
5.1.3.1.3	Entrainment Separator
5.1.3.1.4	Filter
5.1.3.1.5	Condensate Quench Water Exchanger
5.1.3.1.6	Knockout Drum
5.1.3.1.7	Regenerator Overhead Air Cooler
5.1.3.1.8	Regenerator Boiler
5.1.3.1.9	Regenerator
5.1.3.1.10	Solution Filter
5.1.3.1.11	Lean Solution Air Cooler
5.1.3.1.12	Absorber
5.1.3.1.13	Absorber Overhead Entrainment Separator
5.1.3.1.14	Knockout Drum
5.1.3.1.15	Water Wash Tower
5.1.3.1.16	Boiler Feed Water Heater
5.1.3.1.17	Water Wash Circulation Pump
5.1.3.1.18	Condensate Pump
5.1.3.1.19	Lean Solution Pump

[3] Reference: C.F. Braun Dwg. 5102-100-113-XD-1
C.F. Braun Dwg. 5102-100-114-XD-1 (See Appendix)

Item	Description
5.1.3.1.20	Overhead Cooler Pump
5.1.3.1.21	Solution Makeup System
5.1.3.1.22	Antifoam System
5.1.3.1.23	Solution Tank
5.1.3.1.24	Solution Makeup Pump
5.1.3.1.25	Solution Sump Pump
5.1.3.1.26	Antifoam Tank
5.1.3.1.27	Antifoam Pump

5.1.3.2 Clean Fuel Gas Reheating and Saturation[4]

Item	Description
5.1.3.2.1	Clean Gas Heater
5.1.3.2.2	Saturator
5.1.3.2.3	Saturator Heater No. 1
5.1.3.2.4	Regenerator Reboiler
5.1.3.2.5	Condensate Separator
5.1.3.2.6	Demineralized Water/Process Gas Exchanger
5.1.3.2.7	Condensate Separator
5.1.3.2.8	Degasser
5.1.3.2.9	Saturator Heater No. 2
5.1.3.2.10	Condensate/Quench Water Exchanger
5.1.3.2.11	Filter
5.1.3.2.12	Saturator Water Return Pump
5.1.3.2.13	Recovered Water Pump
5.1.3.2.14	Saturator Circulation Pump
5.1.3.2.15	Hot Condensate Pump
5.1.3.2.16	Condensate Pumps

[4] Reference: C.F. Braun Dwg. 5102-100-116-XD-1 (See Appendix)

5.1.4 Byproduct Disposition

5.1.4.1 Ash

Item	Tag Number[5]	Description	Quantity
5.1.4.1.1	120-CO-1(2)-1	Ash Cooler Feed Conveyor (drag flight-type): 18" wide x 40' long, 20 ft lift, 15 tph capacity, 10 hp drive	2
5.1.4.1.2	120-CO-1-2	Ash Collecting Belt Conveyor: 24" belt, 30 tph capacity, 130 ft long, 10 ft lift, 5 hp drive	1
5.1.4.1.3	120-CO-1-3	Ash Storage Belt Conveyor: 24" belt, 30 tph capacity, 500 ft long, 50 ft lift, 7 1/2 hp drive	1
5.1.4.1.4	120-X-1(2)-1	Ash Cooler (rotary-type): 10 tph capacity, ash cooling from 840 °F to 110 °F	2
5.1.4.1.5	120-X-1(2)-2	Rotary Pug Mill: 15 tph capacity, 15 hp drive	2
5.1.4.1.6	120-X-1-3	Clamshell Bucket Loader (diesel driven)	1

5.1.4.2 Sulfur and Lockhopper Gas[6]

5.1.4.2.1 Process Air Blower

5.1.4.2.2 Incinerator Air Blower

5.1.4.2.3 Acid Gas Scrubber

5.1.4.2.4 Acid Gas Preheater

5.1.4.2.5 Muffle Furnace

5.1.4.2.6 Waste Heat Reclaimer

5.1.4.2.7 Reactor No. 1

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[5] Reference: C.F. Braun Dwg. 5102-100-120-XD-1 Rev. 1

[6] Reference: C.F. Braun Dwg. 5102-100-115-XD-1 (See Appendix)

5.1.4.2.8 Sulfur Condenser No. 1
5.1.4.2.9 Reactor No. 2 Feed Heater
5.1.4.2.10 Reactor No. 2
5.1.4.2.11 Sulfur Condenser No. 2
5.1.4.2.12 Reactor No. 3 Feed Heater
5.1.4.2.13 Reactor No. 3
5.1.4.2.14 Sulfur Condenser No. 3
5.1.4.2.15 Incinerator
5.1.4.2.16 Incinerator Waste Heat Boiler
5.1.4.2.17 Vent Stack

5.1.4.3 Waste Sludge

5.1.4.4 Flared Gas

5.2 PRIME CYCLE WATER-COOLED GAS TURBINE-GENERATOR

5.2.1 Flange-to-Flange Gas Turbine

5.2.2 Hydrogen-Cooled Generator

5.2.3 Axial Flow Exhaust

5.2.4 Off-Base Systems

5.3 BOTTOMING CYCLE STEAM TURBINE-GENERATOR

5.3.1 Heat Recovery Steam Generator System

5.3.1.1 Steam Drum

5.3.1.2 Superheater

5.3.1.3 Evaporator

5.3.1.4 Economizer

5.3.1.5 Forced Circulation Water Pump

5.3.1.6 Pipes, Valves, and Fittings

5.3.2 Steam Turbine-Generator

5.3.2.1 155, 100 kW, 3600 rpm, Double Flow Tandem Compound Reheat Steam Turbine: 2400 psia/1000F/1000F/2.5" HgABs HgA exhaust

5.3.2.2 191,500 kVA, 3600 rpm, Direct Connected, 3 Phase, 60 Hz, Hydrogen-Cooled Synchronous Generator: 0.85 pf, 0.58 scr at a maximum H_2 pressure of 30 psia, 15 kV, 375 V static excitation system

5.3.3 Major Mechanical Auxiliaries

5.3.3.1 Mechanical Auxiliary Controls

5.3.3.2 Steam Turbine Condenser

5.3.3.3 Condenser Vacuum Pumps

5.3.3.4 Condensate Pumps

5.3.3.5 Condensate Makeup Pumps

5.3.3.6 Boiler Feed Pumps

5.3.3.7 Deaerator

5.3.3.8 Deaerator Makeup Pumps

5.3.3.9 Deaerator Circulation Pump

5.3.3.10 Flash Tanks

5.4 BALANCE OF PLANT SYSTEMS

5.4.1 Water Supply

5.4.1.1 Source

5.4.1.2 Pumping

5.4.1.3 Storage

5.4.2 Water Treatment

5.4.2.1 Screening

5.4.2.2 Pretreatment

5.4.2.3 Dimineralization

5.4.2.4 Polishing

5.4.3 Air Systems

5.4.3.1 Service Air Compressor (1)

5.4.3.2 Instrument Air System

- 5.4.3.2.1 Instrument Air Compressor (2)
- 5.4.3.2.2 Instrument Air Dryer (2)
- 5.4.3.2.3 Prefilter (2)
- 5.4.3.2.4 Afterfilter (2)

5.4.3.3 Ventilation and Air Conditioning

- 5.4.3.3.1 Administration Building
- 5.4.3.3.2 Warehouse, Shop and Laboratory
- 5.4.3.3.3 Water Treatment Building
- 5.4.3.3.4 Steam Generator Building
- 5.4.3.3.5 Gasification Building (46,000 hp)
- 5.4.3.3.6 Maintenance Shop and Garage
- 5.4.3.3.7 Chlorinator Building
- 5.4.3.3.8 Crushing Building

5.4.4 Auxiliary Boiler

5.4.4.1 Auxiliary Boiler (2)
5.4.4.2 Fuel Oil Day Tank (1)
5.4.4.3 Light Fuel Oil Pump Set (1)
5.4.4.4 Blowdown Tank (1)
5.4.4.5 Deaerator - Feed Pumps Package (1)
5.4.4.6 Chemical Ball Feeder (1)
5.4.4.7 Stack (1)
5.4.4.8 Condensate Return Unit (4)
5.4.4.9 Condensate Return Unit (1)
5.4.5.10 Condensate Return Unit (3)
5.4.5 Emergency Diesel Generator
5.4.6 Waste Heat Rejection
5.4.6.1 Cooling Tower
5.4.6.2 Circulating Water Pump (3)
5.4.6.3 Support Systems Traveling Screen (3)
5.4.6.4 Raw Water Pump (3)
5.4.6.5 Cooling Tower Makeup Pump (2)
5.4.6.6 Auxiliary Cooling Water Pump (3)
5.4.7 Distillate Fuel Unloading
5.4.8 Miscellaneous Fire, Cranes, Tanks, Etc.
5.4.8.1 Fire Pump - Electric Motor-Driven (1)
5.4.8.2 Fire Pump - Diesel Engine-Driven (1)
5.4.8.3 Hose Reel Stations (50)
5.4.8.4 Fire Detectors (200)
5.4.8.5 Manual Fire Alarm Station (50)
5.4.8.6 Fire Extinguisher (150)

5.5 ELECTRICAL AUXILIARY SYSTEM

5.5.1 Station Auxiliary Transformers (2)
12/16/20 MVA, OA/FA/FOA, 13.8 kV, 3 ϕ, 60 Hz

5.5.2 Station Startup Transformer (1)

5.5.3 Gas Turbine Auxiliary Transformers (2)

5.5.4 4.16 kV Metalclad Switchgear

5.5.5 Cooling Tower Substation (1)

5.5.6 Coal Handling Substation (2)

5.5.7 Gasification Substation (1)

5.5.8 Coal Thawing Substations (3)

5.5.9 Station Water Substation (1)

5.5.10 Gas Cleanup Substation (1)

5.5.11 Gas Turbine Auxiliary Standby Substation (1)

5.5.12 Gas Turbine Auxiliary Substation (2)
Transformers, switchgear, and motor control centers

5.5.13 Plant and Steam Turbine Auxiliary Substation (1)
Transformers, switchgear, and motor control centers

5.5.14 Essential Bus (1)

5.6 INTEGRATED PLANT CONTROL--PLANT CONTROL ROOM

5.7 ELECTRICAL POWER SYSTEM

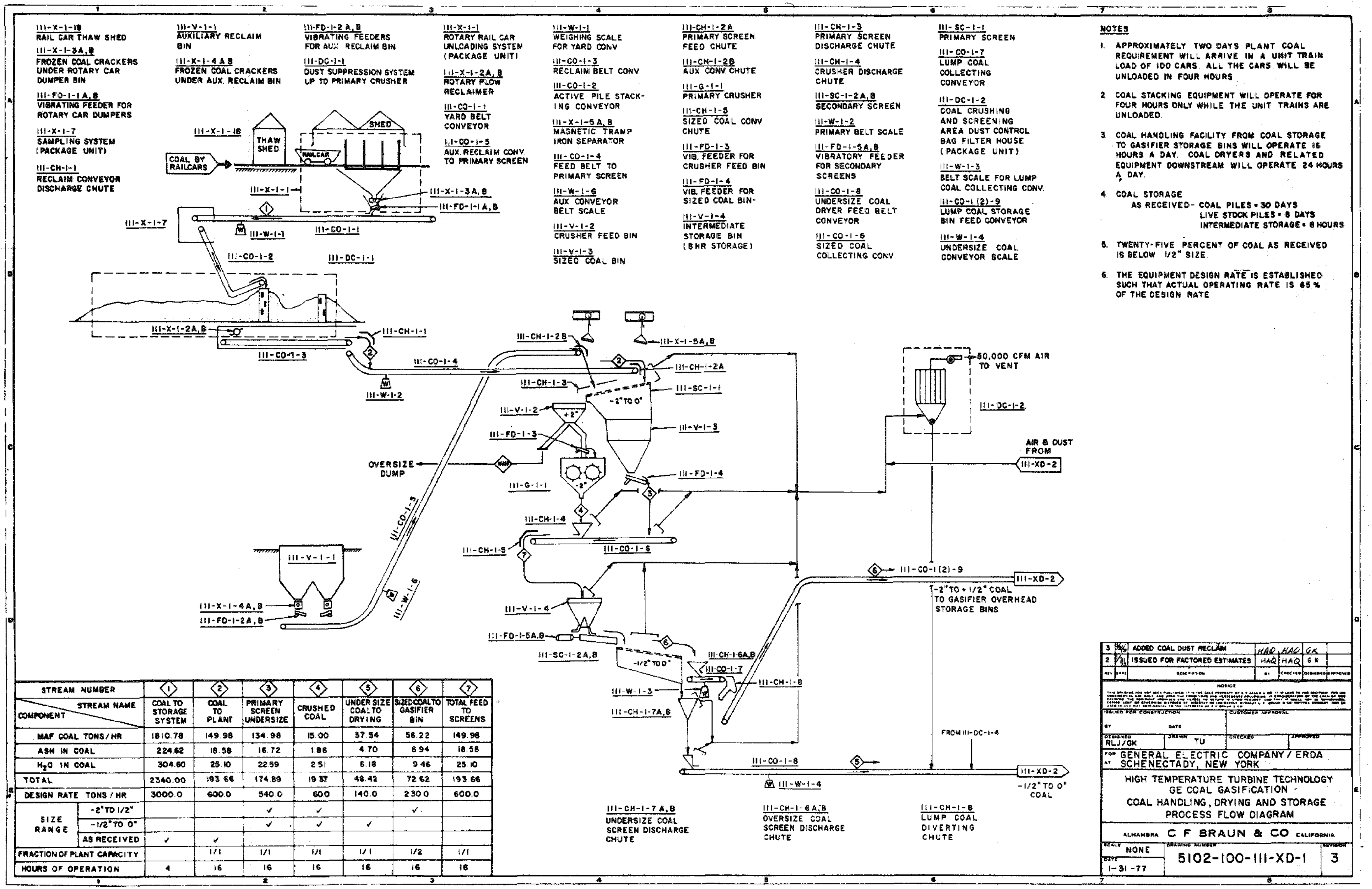
5.7.1 Gas Turbine-Generator Step-Up Transformers (2)

5.7.2 Steam Turbine-Generator Step-Up Transformer (1)

5.7.3 Isolated Phase Bus Ducting

5.7.4 Ground System

5.7.5 Battery System



111-X-1-19
RAIL CAR THAW SHED

111-X-1-3A,B
FROZEN COAL CRACKERS UNDER ROTARY CAR DUMPER BIN

111-FD-1-1A,B
VIBRATING FEEDER FOR ROTARY CAR DUMPERS

111-X-1-7
SAMPLING SYSTEM (PACKAGE UNIT)

111-CH-1-1
RECLAIM CONVEYOR DISCHARGE CHUTE

111-V-1-1
AUXILIARY RECLAIM BIN

111-X-1-4A,B
FROZEN COAL CRACKERS UNDER AUX. RECLAIM BIN

111-FD-1-2A,B
VIBRATING FEEDERS FOR AUX. RECLAIM BIN

111-DC-1-1
DUST SUPPRESSION SYSTEM UP TO PRIMARY CRUSHER

111-X-1-1
ROTARY RAIL CAR UNLOADING SYSTEM (PACKAGE UNIT)

111-X-1-2A,B
ROTARY PLOW RECLAIMER

111-CO-1-1
YARD BELT CONVEYOR

111-CO-1-5
AUX. RECLAIM CONV. TO PRIMARY SCREEN

111-W-1-1
WEIGHING SCALE FOR YARD CONV

111-CO-1-3
RECLAIM BELT CONV

111-CO-1-2
ACTIVE PILE STACKING CONVEYOR

111-X-1-5A,B
MAGNETIC TRAMP IRON SEPARATOR

111-CO-1-4
FEED BELT TO PRIMARY SCREEN

111-W-1-6
AUX CONVEYOR BELT SCALE

111-V-1-2
CRUSHER FEED BIN

111-V-1-3
SIZED COAL BIN

111-CH-1-2A
PRIMARY SCREEN FEED CHUTE

111-CH-1-2B
AUX CONV CHUTE

111-G-1-1
PRIMARY CRUSHER

111-CH-1-5
SIZED COAL CONV CHUTE

111-FD-1-3
VIB. FEEDER FOR CRUSHER FEED BIN

111-FD-1-4
VIB. FEEDER FOR SIZED COAL BIN

111-V-1-4
INTERMEDIATE STORAGE BIN (8 HR STORAGE)

111-CH-1-3
PRIMARY SCREEN DISCHARGE CHUTE

111-CH-1-4
CRUSHER DISCHARGE CHUTE

111-SC-1-2A,B
SECONDARY SCREEN

111-W-1-2
PRIMARY BELT SCALE

111-FD-1-5A,B
VIBRATORY FEEDER FOR SECONDARY SCREENS

111-CO-1-8
UNDERSIZE COAL DRYER FEED BELT CONVEYOR

111-CO-1-6
SIZED COAL COLLECTING CONV

111-SC-1-1
PRIMARY SCREEN

111-CO-1-7
LUMP COAL COLLECTING CONVEYOR

111-DC-1-2
COAL CRUSHING AND SCREENING AREA DUST CONTROL BAG FILTER HOUSE (PACKAGE UNIT)

111-W-1-3
BELT SCALE FOR LUMP COAL COLLECTING CONV.

111-CO-1(2)-9
LUMP COAL STORAGE BIN FEED CONVEYOR

111-W-1-4
UNDERSIZE COAL CONVEYOR SCALE

111-CH-1-7A,B
UNDERSIZE COAL SCREEN DISCHARGE CHUTE

111-CH-1-6A,B
OVERSIZE COAL SCREEN DISCHARGE CHUTE

111-CH-1-8
LUMP COAL DIVERTING CHUTE

NOTES

1. APPROXIMATELY TWO DAYS PLANT COAL REQUIREMENT WILL ARRIVE IN A UNIT TRAIN LOAD OF 100 CARS. ALL THE CARS WILL BE UNLOADED IN FOUR HOURS
2. COAL STACKING EQUIPMENT WILL OPERATE FOR FOUR HOURS ONLY WHILE THE UNIT TRAINS ARE UNLOADED.
3. COAL HANDLING FACILITY FROM COAL STORAGE TO GASIFIER STORAGE BINS WILL OPERATE 16 HOURS A DAY. COAL DRYERS AND RELATED EQUIPMENT DOWNSTREAM WILL OPERATE 24 HOURS A DAY.
4. COAL STORAGE
   AS RECEIVED- COAL PILES = 30 DAYS
   LIVE STOCK PILES = 8 DAYS
   INTERMEDIATE STORAGE = 8 HOURS
5. TWENTY-FIVE PERCENT OF COAL AS RECEIVED IS BELOW 1/2" SIZE.
6. THE EQUIPMENT DESIGN RATE IS ESTABLISHED SUCH THAT ACTUAL OPERATING RATE IS 65% OF THE DESIGN RATE

STREAM NUMBER		1	2	3	4	5	6	7
COMPONENT / STREAM NAME		COAL TO STORAGE SYSTEM	COAL TO PLANT	PRIMARY SCREEN UNDERSIZE	CRUSHED COAL	UNDER SIZE COAL TO DRYING	SIZED COAL TO GASIFIER BIN	TOTAL FEED TO SCREENS
MAF COAL TONS/HR		1810.78	149.98	134.98	15.00	37.54	56.22	149.98
ASH IN COAL		224.62	18.58	16.72	1.86	4.70	6.94	18.58
H_2O IN COAL		304.60	25.10	22.59	2.51	6.18	9.46	25.10
TOTAL		2340.00	193.66	174.89	19.37	48.42	72.62	193.66
DESIGN RATE TONS/HR		3000.0	600.0	540.0	60.0	140.0	230.0	600.0
SIZE RANGE	-2" TO 1/2"			✓	✓		✓	
	-1/2" TO 0"			✓	✓	✓		
	AS RECEIVED	✓	✓					
FRACTION OF PLANT CAPACITY			1/1	1/1	1/1	1/1	1/2	1/1
HOURS OF OPERATION		4	16	16	16	16	16	16

REV	DATE	DESCRIPTION	BY	CHECKED	DESIGNED	APPROVED
3	7/6/77	ADDED COAL DUST RECLAIM	HAQ	HAQ	GK	
2	1/31/77	ISSUED FOR FACTORED ESTIMATES	HAQ	HAQ	GK	

NOTICE

ISSUED FOR CONSTRUCTION
BY
DATE
CUSTOMER APPROVAL

DESIGNED RLJ/GK
DRAWN TU
CHECKED
APPROVED

FOR GENERAL ELECTRIC COMPANY / ERDA
AT SCHENECTADY, NEW YORK

HIGH TEMPERATURE TURBINE TECHNOLOGY
GE COAL GASIFICATION -
COAL HANDLING, DRYING AND STORAGE
PROCESS FLOW DIAGRAM

ALHAMBRA C F BRAUN & CO CALIFORNIA

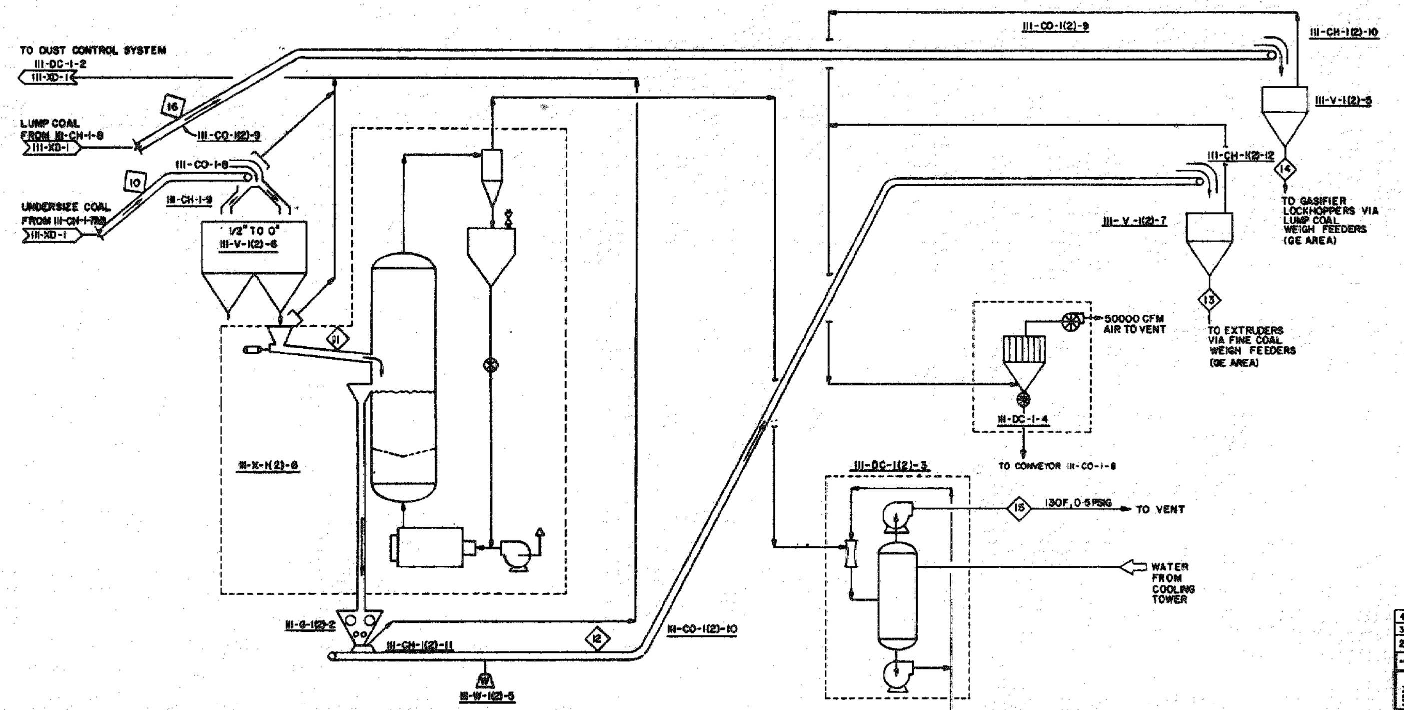
SCALE NONE
DATE 1-31-77
DRAWING NUMBER 5102-100-111-XD-1
REVISION 3

C.F. Braun Drawing 5102-100-111-XD-1 Rev. 3

III-V-I(2)-6	UNDERSIZE COAL STORAGE BIN (12 HR STORAGE)
III-G-I(2)-2	DRIED COAL CRUSHER
III-X-I(2)-6	FLUIDIZED BED DRYER (PACKAGE UNIT)
III-CO-I(2)-10	DRIED COAL CONVEYOR (ENCLOSED)
III-DC-I(2)-3	FLUE GAS DUST CONTROL SYSTEM (PACKAGE UNIT)
III-W-I(2)-5	BELT SCALE FOR DRIED COAL
III-DC-I-4	BAG FILTERS FOR STORAGE BINS (PACAGE UNIT)
III-V-I(2)-5	GASIFIER OVERHEAD STORAGE BINS FOR DRIED COAL (10 HR STORAGE)
III-V-I(2)-5	GASIFIER OVERHEAD STORAGE BINS FOR LUMP COAL (10HR STORAGE)
III-CH-I(2)-10	LUMP COAL BIN CONV. DISCHARGE CHUTE
III-CH-I(2)-12	DRIED COAL STORAGE CONVEYOR DISCHARGE CHUTE
III-CO-I-8	DRYER FEED BELT CONVEYOR
III-CO-I(2)-9	LUMP COAL STORAGE BIN FEED CONVEYOR
III-CH-I-9	FINE COAL DIVERTING CHUTE
III-CH-I(2)-11	DRIED COAL CRUSHER DISCHARGE CHUTE

NOTES

1. THE EQUIPMENT DESIGN RATE IS ESTABLISHED SUCH THAT THE ACTUAL OPERATING RATE IS 65 PERCENT OF THE DESIGN RATE.
2. UNDERSIZE COAL STORAGE BINS III-V-I(2)-6 HAVE 12 HOURS SURGE CAPACITY.
3. GASIFIER OVERHEAD STORAGE BINS III-V-I(2)-5 AND III-V-I(2)-7 ARE DESIGNED FOR 10 HOURS SURGE CAPACITY.
4. FOURTEEN GASIFIERS ARE ARRANGED IN TWO PARALLEL BANKS WITH SEVEN IN EACH BANK.



STREAM NUMBER		10	11	12	13	14	15	16	17
COMPONENT	STREAM NAME	UNDERSIZE COAL TO DRYING	DRYER FEED	DRIED COAL TO GASIFIER BINS	DRIED COAL TO GASIFIERS	SIZED COAL TO GASIFIERS	FLUE GAS TO STACK	SIZED COAL TO GASIFIER BINS	
MAF COAL	TONS/HR	37.54	18.77	18.34	18.34	56.22		56.22	
ASH		4.70	2.35	2.30	2.30	6.94		6.94	
H_2O		6.18	3.09	0.63	0.63	9.46		9.46	
TOTAL		48.42	24.21	21.27	21.27	72.62		72.62	
CFM, GAS/TEMPERATURE °F		/70		/155			9650/130		
COAL SIZES	-2" TO 1/2"					✓		✓	
	-1/2" TO 0"	✓	✓	✓	✓				
DESIGN RATE TONS/HR		140.0	40.0	40.0		230.0	12000CFM	230.0	
FRACTION OF PLANT CAPACITY		1/1	1/2	1/2	1/2	1/2	1/2	1/2	
HOURS OF OPERATION		16	24	24	24	24	24	16	

REV	DATE	DESCRIPTION	BY	CHECKED	DESIGNED	APPROVED
4	[illegible]	ADDED COAL DUST RECLAIM	HAQ	HAQ	GK	
3	[illegible]	REARRANGED LETTERING & NOTES	HAQ	HAQ	GK	
2	[illegible]	ISSUED FOR FACTORED ESTIMATES	HAQ	HAQ	GK	

NOTICE

[illegible]

ISSUED FOR CONSTRUCTION
BY
DATE

CUSTOMER APPROVAL

DESIGNED RLJ/GK
DRAWN
CHECKED
APPROVED

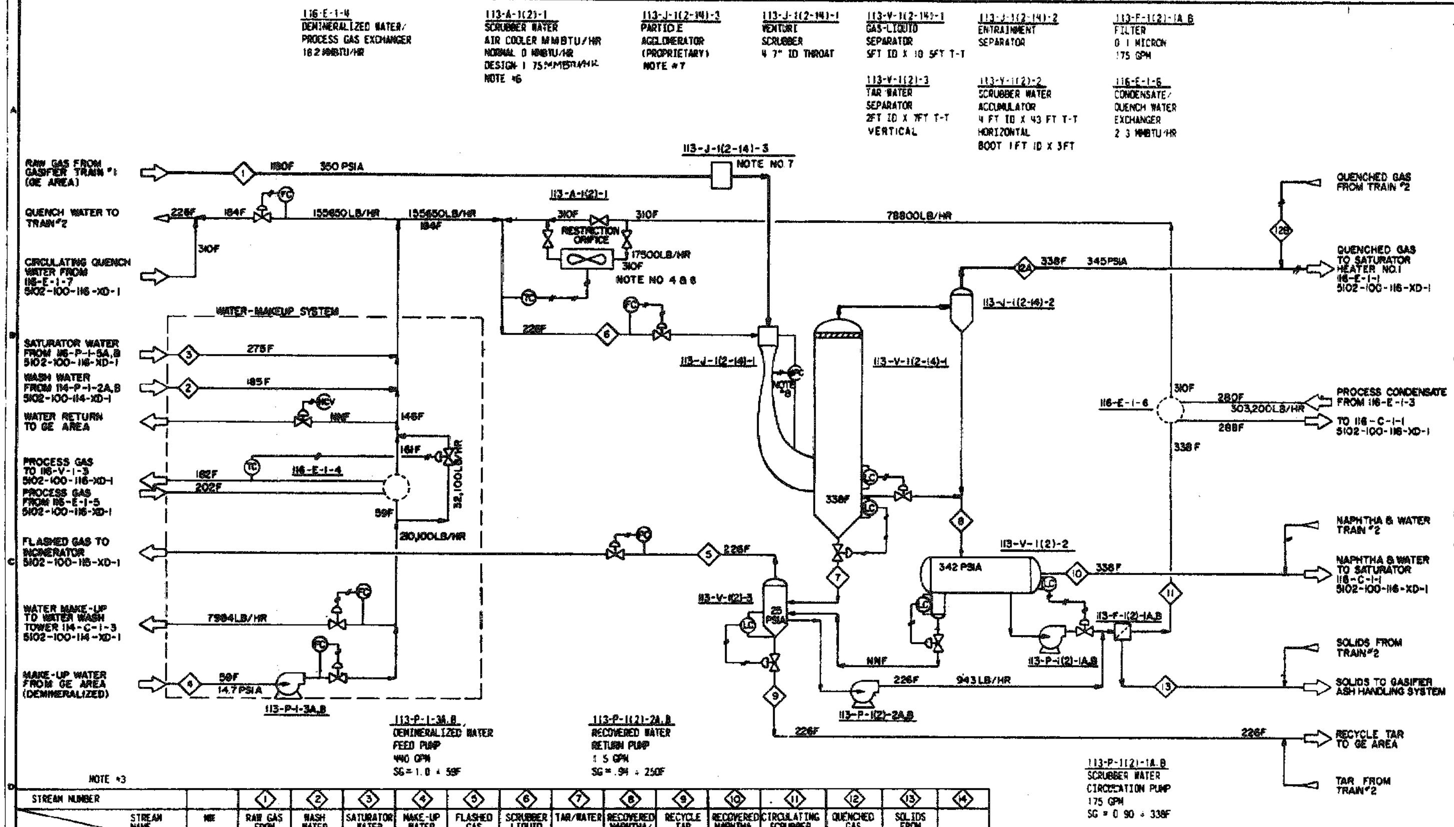
FOR GENERAL ELECTRIC COMPANY/ERDA
AT SCHENECTADY, NEW YORK

HIGH TEMPERATURE TURBINE TECHNOLOGY
GE COAL GASIFICATION
COAL HANDLING, DRYING AND STORAGE
PROCESS FLOW DIAGRAM

ALHAMBRA **C F BRAUN & CO** CALIFORNIA

SCALE NONE
DATE 1-31-77
DRAWING NUMBER 5102-100-111-XD-2
REVISION 4

C.F. Braun Drawing 5102-100-111-XD-2 Rev. 4



NOTES

1 ATMOSPHERIC PRESSURE IS 14 7 PSIA

2 EQUIPMENT WILL BE SIZED FOR 105 PERCENT OF NORMAL FLOW PER GE INSTRUCTION.

3. THE MATERIAL BALANCE SHOWN REPRESENTS 100 PERCENT OF NORMAL FLOW HOWEVER THE FLOW DIAGRAM REPRESENTS ONE OF TWO EQUAL PARALLEL TRAINS WITH THE EXCEPTION OF WATER MAKE-UP SYSTEM. THE WATER MAKE-UP SYSTEM IS FOR BOTH THE TRAINS

4. THE DUTY OF THIS AIR COOLER DEPENDS ON THE MAKE-UP WATER TEMPERATURE WHICH VARIES FROM 59F AND 85F

5 RAW GAS FROM GASIFIERS TO THE QUENCH UNIT CONTAINS 2300 PPMW OF SOLIDS WITH THE FOLLOWING SIZE DISTRIBUTION

SIZES IN MICRONS	WEIGHT PERCENT
BETWEEN 10 AND 100	2
BETWEEN 1 AND 10	70
LESS THAN 1	28
	100

TWO WEIGHT PERCENT OF THE TOTAL SOLIDS ARE POTASSIUM AND SODIUM. BASED ON GE'S CLEAN GAS SPECIFICATION ABOUT 99.8 WEIGHT PERCENT OF THE TOTAL SOLIDS IN THE RAW GAS SHOULD BE REMOVED.

6 NO AIR COOLING IS REQUIRED FOR NORMAL OPERATION. AIR COOLING WILL BE REQUIRED WHEN THE MAKE-UP WATER TEMPERATURE IS HIGHER THAN 59F. THE AIR COOLER IS DESIGNED TO HANDLE A TEMPERATURE RISE UP TO 26F.

7. THE UNIT HAS BEEN SELECTED ON A TENTATIVE BASIS. THIS IS A HIGH INTENSITY IONIZER OFFERED BY AIR POLLUTION SYSTEMS INC (APS) OF TUKWILA. WASHINGTON. APS CLAIMS THAT THE UNIT WILL AGGLOMERATE SUBMICRON ~~PARTICLES~~ AND HENCE WILL IMPROVE VENTURI SCRUBBER'S EFFICIENCY FROM 98 TO 99.8 PERCENT.

8. THE VENTURI THROAT OPENING WILL BE AUTOMATICALLY ADJUSTED TO OBTAIN CONSTANT PRESSURE DROP.

9. EQUIPMENT NUMBER DETAILS

113 - P - 1 (2-14) - 2 A,B
- 113: UNIT NUMBER
- P: EQUIP TYPE
- 1: TRAIN NUMBER
- (2-14): TOTAL NO. OF TRAINS
- 2: ITEM NUMBER
- A,B: INDICATES SPARING

NOTE #3

STREAM NUMBER		1	2	3	4	5	6	7	8	9	10	11	12	13	14
COMPONENT / STREAM NAME	MW	RAW GAS FROM GASIFIERS	WASH WATER FROM AGR	SATURATOR WATER	MAKE-UP WATER	FLASHED GAS	SCRUBBER LIQUID FEED	TAR/WATER	RECOVERED NAPHTHA/ WATER	RECYCLE TAR	RECOVERED NAPHTHA	CIRCULATING SCRUBBER WATER	QUENCHED GAS A + B	SOLIDS FROM FILTERS	
H_2 LB-MOL/HR	2.016	3477.9											6955.8		
N_2	28.02	9008.8				0.1	0.2	0.1	0.2			0.2	18017.4		
CO	28.01	6109.7				0.1	0.1	0.1	0.1			0.1	12219.2		
CO_2	44.01	1120.3				1.2	1.6	1.3	1.5			1.6	2238.2		
H_2S	34.08	217.4				0.3	0.5	0.4	0.5			0.5	434.2		
COS	60.08	16.4											32.8		
NH_3	17.03	12.2				0.7	1.8	1.1	1.4			1.8	23.0		
CH_4	16.04	932.2											1864.4		
C_2H_4	28.05	53.6											107.1		
C_2H_6	30.07	75.3											150.5		
PHENOL	94.1	15.3				0.1	0.1	0.1	0.1			0.1	30.4		
NAPHTHA	145.0	91.9							0.5		0.5		182.7		
TAR-OILS TAR	210.6	17.0						3.6		3.6			26.9		
TOTAL LB-MOL HR (DRY)		21148.0				2.5	4.3	6.7	4.3	3.6	0.5	4.3	42282.6		
H_2O		1789.2	832.4	4701.5	12184.6	8.3	13004.6	64.9	4325.8	5.2	7.5	4366.9	20806.1	3.0	
TOTAL LB-MOL HR (WET)		22937.2	832.4	4701.5	12184.6	10.8	13008.9	71.6	4330.1	8.8	8.0	4371.2	63088.7	3.0	
SOLIDS LB/HR		1283						92.6	357	926			2	357	
TOTAL LB/HR (WET)		559020	15000	84720	219570	240	234480	2960	78510	1780	210	18830	1424110	410	
DESIGN LB/HR		587000	16000	89000	231000	250	246000	3100	82500	1870	220	83000	1495000	430	

REV	DATE	DESCRIPTION	BY	CHECKED	DESIGNED	APPROVED
0	[illegible]	ISSUED FOR ESTIMATES ONLY	HAQ	HAQ	RLJ	

NOTICE

[illegible]

ISSUED FOR CONSTRUCTION
BY
DATE

CUSTOMER APPROVAL

DESIGNED	DRAWN	CHECKED	APPROVED
RLJ	TG	HAQ	

FOR GENERAL ELECTRIC COMPANY/ERDA
AT SCHENECTADY, NEW YORK

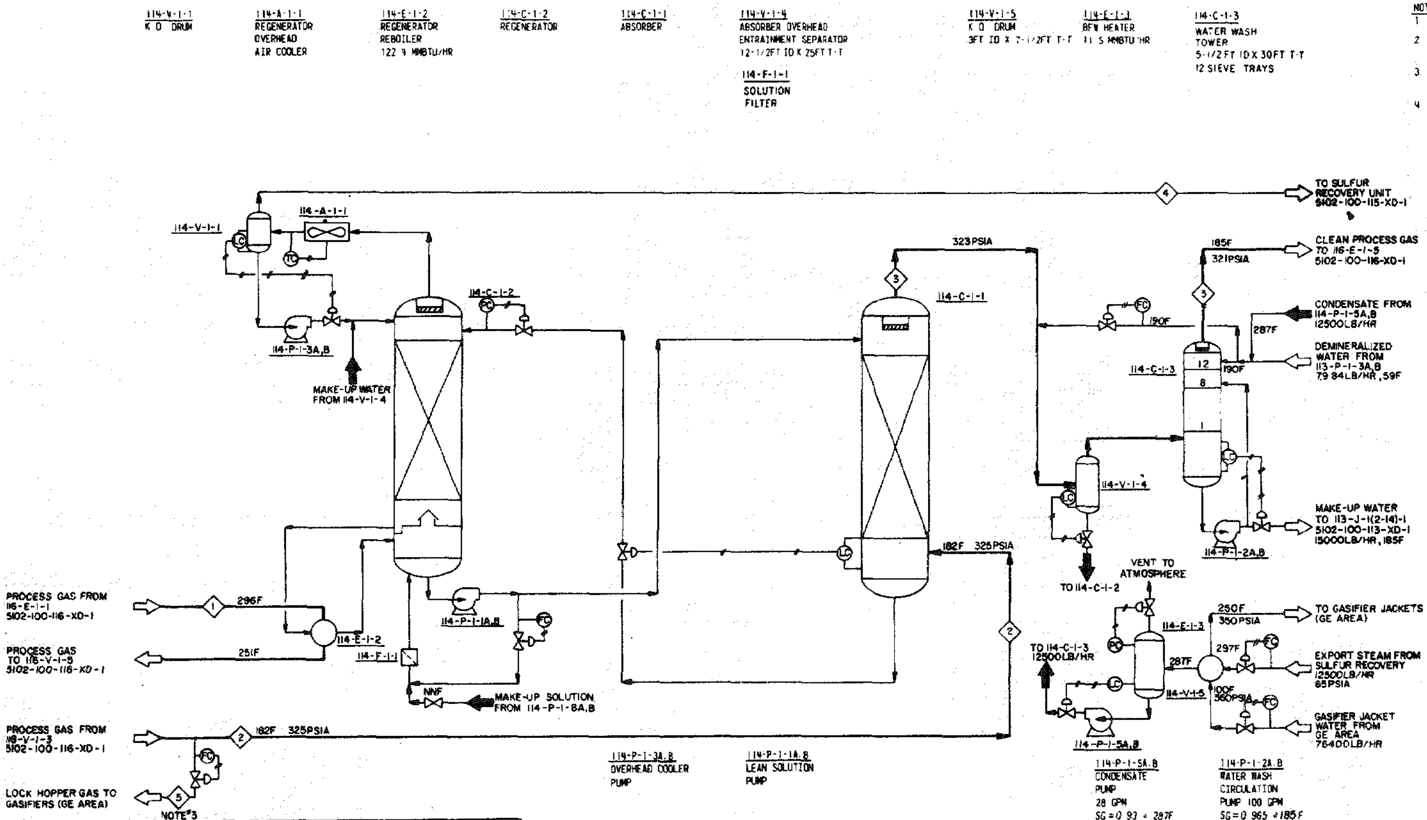
HIGH TEMPERATURE TURBINE TECHNOLOGY
GE COAL GASIFICATION
RAW GAS QUENCH
PROCESS FLOW DIAGRAM

ALHAMBRA C F BRAUN & CO CALIFORNIA

SCALE	DRAWING NUMBER	REVISION
NONE	5102-100-113-XD-1	0

DATE 10-19-76

C.F. Braun Drawing 5102-100-113-XD-1



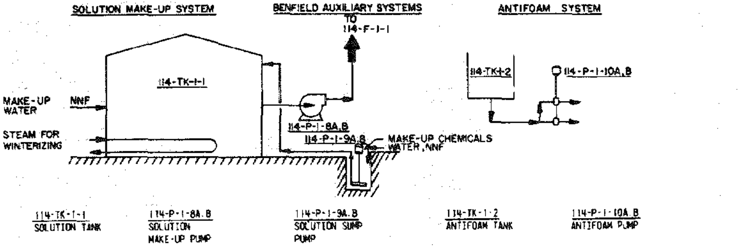
STREAM NUMBER	MW	1	2	3	4	5	6
STREAM NAME / COMPONENTS		QUENCHED GAS	ABSORBER FEED	ABSORBER EFFLUENT	SOUR GAS	LOCK HOPPER GAS	
H_2 LB-MOL/HR	2 016	6955 8	6907 4	6904 6	2 8	48 0	
N_2	28 02	18017 4	17890 0	17886 4	3 6	124 3	
CO	28 01	12219 2	12132 4	12130 0	2 4	84 3	
CO_2	44 01	2238 2	2203 1	1101 6	1117 6	15 3	
H_2S	34 08	434 2	426 5	29 4	413 4	3 0	
COS	60 08	32 8	32 6	16 3		0 2	
NH_3	17 03	23 0	2 2		2 2		
CH_4	16 04	1864 4	1850 9	1850 4	0 5	12 9	
C_2H_4	28 05	107 1	106 4	106 3	0 1	0 7	
C_2H_6	30 07	150 5	149 4	149 3	0 1	1 0	
PHENOL	94 1	30 4	17 1	17 1		0 1	
NAPHTHA	145 0	182 7	36 2	36 2		0 3	
TAR TAR-OILS	210 0	26 9					
TOTAL LB-MOL/HR (DRY)		42282 6	41754 2	40227 6	1543 0	290 1	
H_2O		20806 1	1040 0	1161 1	265 0	7 2	
TOTAL LB-MOL/HR (WET)		63088 7	42794 2	41388 7	1808 0	297 3	
TOTAL LB/HR (WET)		1424110	1031240	970200	68290	7170	
DESIGN LB/HR		1495000	1083000	1019000	72000	8000	

NOTES
1 ATMOSPHERIC PRESSURE IS 14 7 PSIA
2 EQUIPMENT WILL BE SIZED FOR 105 PERCENT OF NORMAL FLOW PER GE'S INSTRUCTION
3 FURTHER PROCESSING OF STREAM ◇5 WILL BE DONE BY GE
4 EQUIPMENT NUMBER DETAILS
113 - P - 1 (2-14) - 2 A B
UNIT NUMBER
EQUIP TYPE
TRAIN NUMBER
TOTAL NO OF TRAINS
ITEM NUMBER
INDICATES SPARING

SOLUTION MAKE-UP SYSTEM

BENFIELD AUXILIARY SYSTEMS

ANTIFOAM SYSTEM



REV	DATE	DESCRIPTION	BY	CHECKED	DESIGNED	APPROVED
0	7/76	ISSUED FOR ESTIMATES ONLY	HAG	HAG	RLC	

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BY
DATE
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DRAWN
CHECKED HAG
APPROVED

FOR GENERAL ELECTRIC COMPANY/ERDA
AT SCHENECTADY, NEW YORK

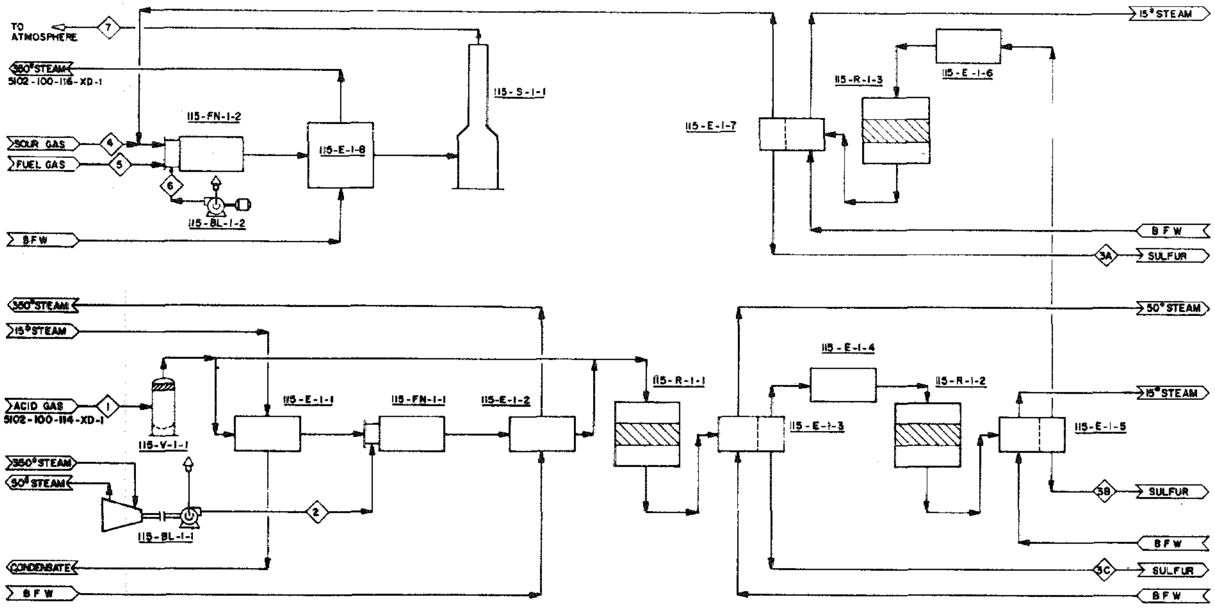
HIGH TEMPERATURE TURBINE TECHNOLOGY
GE COAL GASIFICATION
ACID GAS REMOVAL
PROCESS FLOW DIAGRAM

ALHAMBRA C F BRAUN & CO CALIFORNIA

SCALE NONE
DATE 12-10-76
DRAWING NUMBER 5102-100-114-XD-1
REVISION 0

C.F. Braun Drawing 5102-100-114-XD-1

115-FN-1-2 INCINERATOR
115-BL-1-1 PROCESS AIR BLOWER
115-BL-1-2 INCINERATOR AIR BLOWER
115-V-1-1 ACID GAS SCRUBBER
115-E-1-1 ACID GAS PREHEATER
115-FN-1-1 MUFFLE FURNACE
115-E-1-8 INCINERATOR WASTE HEAT BOILER
115-S-1-1 VENT STACK
115-E-1-2 WASTE HEAT RECLAIMER
115-R-1-1 REACTOR NO. 1
115-E-1-3 SULFUR CONDENSER NO. 1
115-E-1-7 SULFUR CONDENSER NO. 3
115-E-1-4 REACTOR NO 2 FEED HEATER
115-R-1-3 REACTOR NO 3
115-R-1-2 REACTOR NO 2
115-E-1-6 REACTOR NO. 3 FEED HEATER
115-E-1-5 SULFUR CONDENSER NO. 2



NOTES

1. THE CLAUS SULFUR RECOVERY UNIT IS A PACKAGE UNIT SUPPLIED BY THE ORTLOFF CORPORATION OF MIDLAND, TEXAS.

2. THE STREAM COMPOSITIONS AND BLOCK FLOW DIAGRAM ARE FROM THE ORTLOFF CORPORATION DRAWING NO. R-0250-20-001 DATED 11-23-76

3. EQUIPMENT NUMBER DETAILS
113 - P - 1 (2-(4) - 2 A,B
UNIT NUMBER
EQUIP TYPE
TRAIN NUMBER
TOTAL NO OF TRAINS
ITEM NUMBER
INDICATES SPARING

STREAM NUMBER		1	2	3	4	5	6	7							
DESCRIPTION / COMPONENT	MOL WT	ACID GAS	PROCESS AIR	A+B+C LIQUID SULFUR	LOCK HOPPER OFF-GAS	FUEL GAS	INCINERATOR AIR	STACK EFFLUENT	EXPORT 350# STEAM	EXPORT 50# STEAM	EXPORT 15# STEAM	BFW TO PLANT			
O_2 LB-MOL/HR	32.00		210.5				260.4	55.8							
H_2	2.016	2.8			48.0										
N_2	28.02	3.6	791.7		124.3		979.7	1900.4							
CO	28.01	2.4			84.3										
CO_2	44.01	1117.8			15.3			1279.3							
H_2S	34.08	413.4			3.0										
COS	60.08				0.2										
NH_3	17.03	2.2			0.1										
CH_4	16.04	0.5			12.9	32.5									
C_2H_4	28.05	0.1			0.7										
C_2H_6	30.07	0.1			1.0	4.8									
SO_2	64.06							21.6							
S	32.06			394.8											
TOTAL (DRY) LB-MOL/HR		1543.0	1002.2	394.8	289.8	37.3	1240.1	3257.1							
H_2O		265.0	24.2		7.9		29.9	908.6	1865.1	1343.3	404.1	3791.3			
TOTAL (WET) LB-MOL/HR		1808.0	1026.4	394.8	297.7	37.3	1270.0	4165.7	1865.1	1343.3	404.1	3791.3			
TOTAL LB/HR		68290	29350	12660	7130	670	36320	129090	33600	24200	7280	68300			
DESIGN LB/HR		72000	30800	13200	7500	700	38100	135500							

REV	DATE	DESCRIPTION	BY	CHECKED	DESIGNED	APPROVED
0	12/9	ISSUED FOR ESTIMATES ONLY	HAQ	HAQ	ORTLOFF	

NOTICE

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BY
DATE
CUSTOMER APPROVAL

DESIGNED ORTLOFF CORP
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APPROVED

FOR GENERAL ELECTRIC COMPANY / ERDA
AT SCHENECTADY, NEW YORK

HIGH TEMPERATURE TURBINE TECHNOLOGY
GE COAL GASIFICATION
CLAUS SULFUR RECOVERY
BLOCK FLOW DIAGRAM

ALHAMBRA C F BRAUN & CO CALIFORNIA

SCALE NONE
DATE 12/9/76
DRAWING NUMBER 5102-100-115-XD-1
REVISION 0

C.F. Braun Drawing 5102-100-115-XD-1

114-E-1-2
REGENERATOR
REBOILER
1224 MM BTU/HR

116-E-1-5
CLEAN GAS
HEATER
66 8 MM BTU/HR

116-V-1-4
DEGASSER
2FT ID X 5FT T-T

116-E-1-1
SATURATOR
HEATER NO 1
198 5 MM BTU/HR

116-V-1-2
CONDENSATE SEPARATOR
13FT ID X 27FT T-T
HORIZONTAL
BOOT 1FT X 2FT

116-E-1-2
SATURATOR
HEATER NO 2
26 5 MM BTU/HR

116-E-1-7
CONDENSATE/
QUENCH WATER
EXCHANGER-2
2.3 MM BTU/HR

116-C-1-1
SATURATOR
11 SPLASH DECKS
40% OPEN AREA
16FT DIAMETER
40FT HIGH T-T

116-E-1-6
CONDENSATE/
QUENCH WATER
EXCHANGER-1
2.3 MM BTU/HR

116-F-1-1A,B
FILTER-1
0 1 MICRON

116-F-1-2A,B
FILTER-2
0 1 MICRON

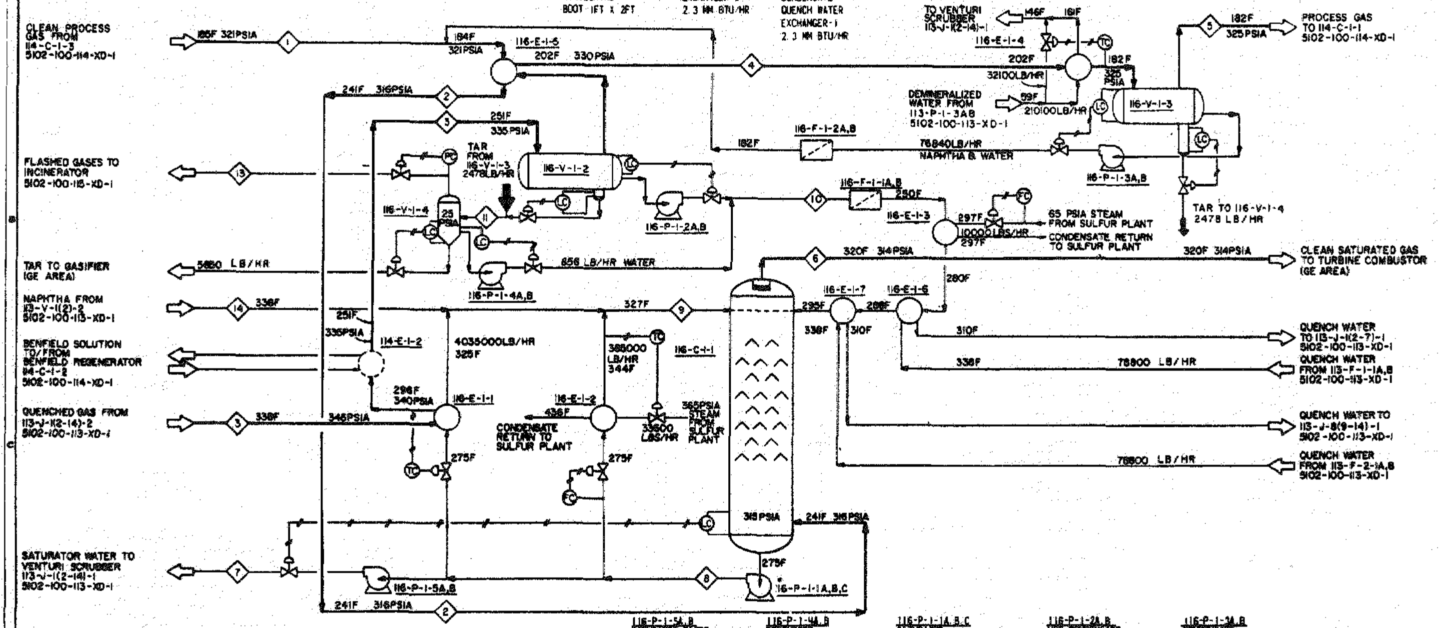
116-E-1-3
CONDENSATE
HEATER
9.0 MM BTU/HR

116-E-1-4
DEMINERALIZED WATER
PROCESS GAS
EXCHANGER
18 2 MM BTU/HR

116-V-1-3
CONDENSATE
SEPARATOR
10FT ID X 23FT T-T
HORIZONTAL
BOOT 1 1/2 FT X 2 1/2 FT

NOTES

1. ATMOSPHERIC PRESSURE IS 14 7 PSIA
2. EQUIPMENT WILL BE SIZED FOR 105 PERCENT OF NORMAL FLOW PER GE INSTRUCTION
3. THIS MATERIAL BALANCE IS FOR 100 PERCENT OF NORMAL FLOW.
4. EQUIPMENT NUMBER DETAILS
   113 - P - 1 (2-14) - 2 A,B
   UNIT NUMBER
   EQUIP TYPE
   TRAIN NUMBER
   TOTAL NO OF TRAINS
   ITEM NUMBER
   INDICATES SPARING



116-P-1-5A,B
SATURATOR WATER
RETURN PUMP
182 GPM
SG= 0.93 @ 275F

116-P-1-4A,B
RECOVERED
WATER PUMP
2 GPM
SG=0 95 @ 251F

116-P-1-1A,B,C
SATURATOR
CIRCULATION PUMPS
4860 GPM EACH
2-50% CAPACITY-OPERATING
SG= 0.93 @ 275F

116-P-1-2A,B
HOT CONDENSATE
PUMPS
650 GPM
SG= 0.95 @ 251F

116-P-1-3A,B
CONDENSATE
PUMPS
162 GPM
SG= 0.97 @ 182F

NOTE #3

STREAM NO	MW	①	②	③	④	⑤	⑥	⑦	⑧	⑨	⑩	⑪	⑫	⑬	⑭	⑮
STREAM NAME / COMPONENTS		CLEAN PROCESS GAS	CLEAN GAS TO SATURATOR	RAW QUENCHED GAS	PARTIALLY COOLED QUENCH GAS	FEED TO ACID GAS REMOVAL UNIT	CLEAN RESATURATED GAS	SATURATOR WATER BLEED	SATURATOR BOTTOMS LIQUID	SATURATOR LIQUID FEED	HOT AQUEOUS CONDENSATE	RECYCLE TAR	RECYCLE CONDENSATE	FLASHED GAS	RECOVERED NAPHTHA	
H_2 LB-MOL/HR	2.016	6904.6	6904.8	6955.8	6955.6	6955.4	6905.0				0.2		0.2			
N_2	28.02	17886.4	17887.1	18017.4	18015.0	18014.3	17889.5				2.4		0.7			
CO	28.01	12130.0	12130.9	12219.2	12217.6	12216.7	12132.5				1.6		0.9			
CO_2	44.01	1101.6	1108.0	2238.2	2224.9	2218.4	1121.3				13.3	0.1	6.4	0.1		
H_2S	34.08	29.4	30.1	434.2	430.2	429.5	34.1				4.0		0.7			
COS	60.08	16.3	16.3	32.8	32.8	32.8	16.3									
NH_3	17.03		6.2	23.0	8.5	2.2	20.7				14.5	0.1	6.2	0.1		
CH_4	16.04	1850.4	1850.8	1864.4	1864.2	1863.8	1851.0				0.2		0.4			
C_2H_4	28.05	106.3	106.3	107.1	107.1	107.1	106.3									
C_2H_6	30.07	149.3	149.3	150.5	150.4	150.4	149.4				0.1					
PHENOL	94.1	17.1	28.1	30.4	28.2	17.2	30.3				2.2		11.0			
NAPHTHA	145.0	36.2	149.4	182.7	149.7	36.5	183.4			1.0	33.0		113.2		1.0	
TAR-OILS/TAR	210.0			26.9	11.6							26.9				
TOTAL LB-MOL/HR (DRY)		40227.6	40367.3	42282.6	42196.0	42045.3	40439.8			1.0	71.5	27.1	139.9	0.2	1.0	
H_2O		1079.3	4348.1	20806.1	4316.9	1047.2	16149.8	4701.5	250061.2	245291.0	16488.2	38.3	3268.8	1.9	15.0	
TOTAL LB-MOL/HR (WET)		41306.9	44715.4	63088.7	46512.9	43091.5	56589.6	4701.5	250061.2	245292.0	16559.7	65.4	3408.7	2.1	16.0	
TOTAL LB/HR (WET)		968730	1045540	1424110	1117730	1038400	1264430	84720	4506100	4420290	303200	6390	76820	40	415	
DESIGN LB/HR		1017000	1098000	1495000	1174000	1090000	1328000	89000	4731000	4641000	319000	6700	81000	100	450	

REV	DATE	DESCRIPTION	BY	CHECKED	DESIGNED	APPROVED
0	1/24	ISSUED FOR ESTIMATES ONLY	HAG	HAG	RLJ	

NOTICE

ISSUED FOR CONSTRUCTION
BY
DATE
CUSTOMER APPROVAL

DESIGNED RLJ
DRAWN TG
CHECKED HAG
APPROVED

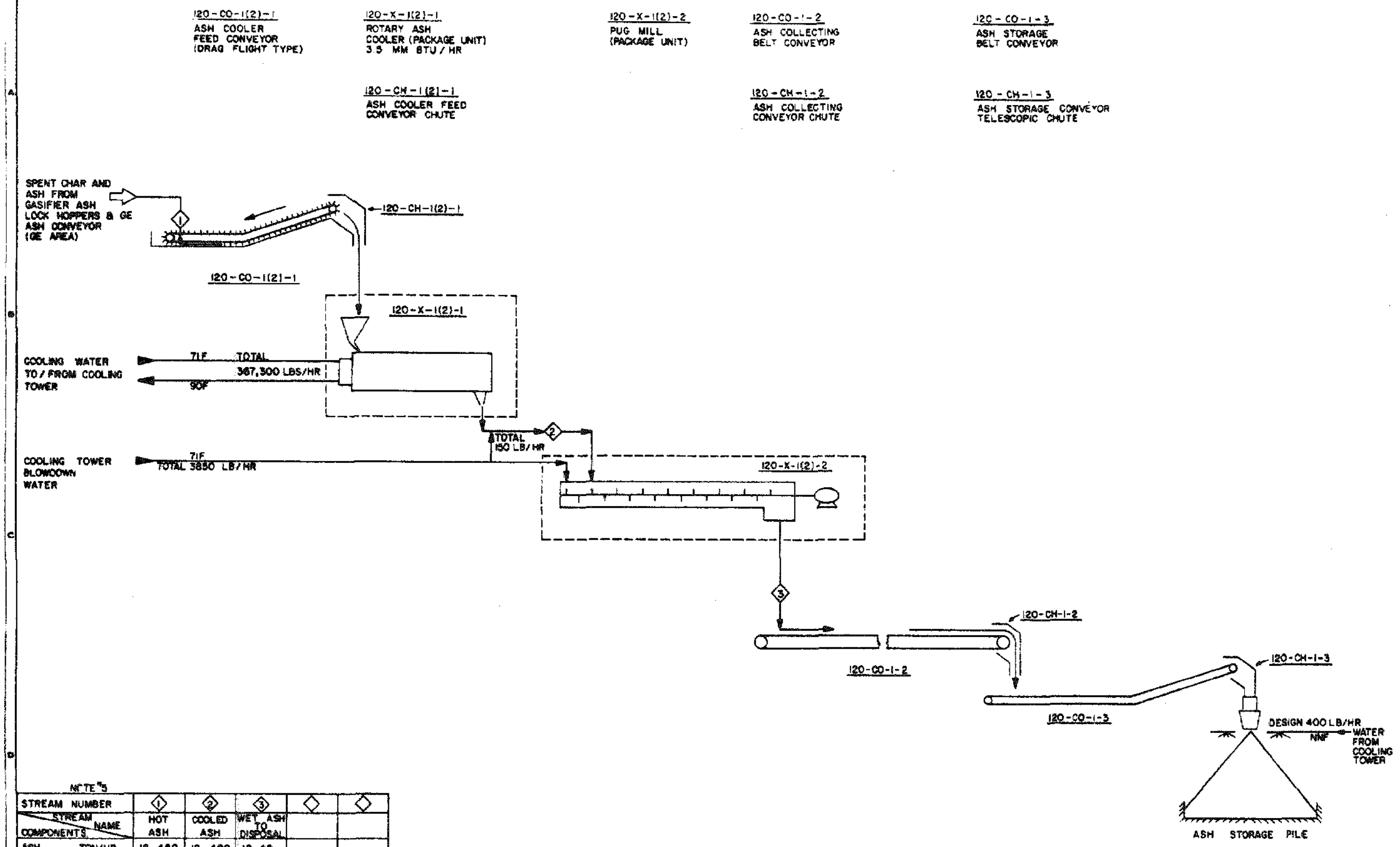
FOR GENERAL ELECTRIC COMPANY/ERDA
AT SCHENECTADY, NEW YORK

HIGH TEMPERATURE TURBINE TECHNOLOGY
GE COAL GASIFICATION
CLEAN GAS REHEATING & SATURATION
PROCESS FLOW DIAGRAM

ALHAMBRA C F BRAUN & CO CALIFORNIA

SCALE NONE
DATE 10-28-76
DRAWING NUMBER 5102-100-116-XD-1
REVISION 0

C.F. Braun Drawing 5102-100-116-XD-1



NOTES

1. ATMOSPHERIC PRESSURE IS 14.7 PSIA
2. EQUIPMENT IS SIZED SUCH THAT THE NORMAL OPERATING CAPACITY IS 65% OF THE DESIGNED RATE.
3. ASH FROM THE PILE WILL BE RECLAIMED BY CLAMSHELL LOADER INTO RAILROAD CARS OR TRUCKS FOR HAULING AWAY FROM THE PLANT SITE
4. SEVEN DAYS STORAGE OF ASH WILL BE PROVIDED.
5. THE MATERIAL BALANCE SHOWN REPRESENTS 100 PERCENT OF NORMAL PLANT CAPACITY.

NOTE #5

STREAM NUMBER	①	②	③	◇	◇
STREAM NAME / COMPONENTS	HOT ASH	COOLED ASH	WET ASH TO DISPOSAL		
ASH TON/HR	18.480	18.480	18.48		
CHAR	0.308	0.308	0.308		
WATER	—	0.075	1.925		
TOTAL	18.788	18.863	20.713		
DESIGN	30.0	30.0	30.0		
TEMPERATURE °F	840	110	100		
PRESSURE PSIA	14.7	14.7	14.7		

REV	DATE	DESCRIPTION	BY	CHECKED	DESIGNED	APPROVED
1	2/17/77	ISSUED FOR ESTIMATE	HAQ	HAQ	GK	
0	12/24/76	ISSUED FOR REVIEW	RLJ		RLJ	

NOTICE

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ISSUED FOR CONSTRUCTION
BY
DATE
CUSTOMER APPROVAL

DESIGNED RLJ
DRAWN V. S. Tchorkhutian
CHECKED
APPROVED

FOR GENERAL ELECTRIC COMPANY / ERDA
AT SCHENECTADY, NEW YORK

HIGH TEMPERATURE TURBINE TECHNOLOGY
GE COAL GASIFICATION
ASH HANDLING AND DISPOSAL
PROCESS FLOW DIAGRAM

ALHAMBRA C F BRAUN & CO CALIFORNIA

SCALE NONE
DATE 12-24-76
DRAWING NUMBER 5102-100-120-XD-1
REVISION 1

C.F. Braun Drawing 5102-100-120-XD-1 Rev. 1

Section 6

SYSTEM AND FACILITY DESCRIPTIONS

6.1 DESCRIPTION OF FUELS PLANT

The fuel plant includes the following subsystems:

1. Coal handling, storage, and preparation
2. Advanced fixed-bed gasification
3. Gas cleanup system and saturator
4. Tail gas cleanup and waste disposal systems

6.1.1 The Coal Handling, Storage, and Preparation System

The basic principle of the system design is the reception of 10,000 tons of coal to the site in one 100-car unit train every other day. The unloading facility has a 2500-ton/hr capacity, based on a planned four-(4) hour unloading time. The coal handling facility, which handles the coal from storage to sizing (-2 in. to + 1/2 in.), operates 16 hours per day and has a 300-ton/hr capacity.

The advanced fixed-bed gasification system includes 14 gasifiers which are arranged in two modules of seven gasifiers each. The coal handling facility consists of two trains, one to serve each seven-unit gasifier module; based on a 21.5-hour-per-day operation, each coal handling train has a 112.5-ton-per-hour capacity. The sized coal is transported to overhead bunkers, one for each gasifier.

The undersized coal (25% of the as-received coal) is dried and transported to overhead storage in two trains, each with a capacity of 35 tons per hour, based on a 16-hour-per-day operation.

6.1.2 The Advanced Fixed-Bed Gasification System

The gasification system consists of 14 gasifier vessels, arranged in two trains with headering flexibility to permit interconnectiion of both trains. Two lockhoppers, a single extruder, and a fines/tar mixer are close-coupled to each gasifier vessel. Each vessel is equipped with an upper and a lower stirrer, each capable of both vertical and rotary motion to assure satisfactory operation with caking coal at low steam:air ratios.

The gasification vessels are jacketed and have a steam generation capacity equal to about half of the process steam demands.

6.1.3 Gas Cleanup System and Saturator

Each vessel is equipped with a close-coupled raw gas quench, wherein the gas is adiabatically cooled to its saturation point; simultaneously, tars, oils, water soluable gases, such as phenols, and any fines are removed. The tars are degassed and then mixed with the coal fines as a binder before the mixture is extruded into the gasification vessel. The scrub water is recycled following cleanup and cooling.

The raw gas leaving the quench is cooled to 185 ^{o}F before entering the Benfield absorbent units, where condensed water and naphtha is heated and injected into the clean product gas in the saturator.

The Benfield and gas removal unit consists of an acid gas absorption column, a solution regeneration column, a solution reboiler, a solution cooler, a solution circulating pump, a regenerator overhead cooler, an overhead condensate return pump, and a solution filter. The raw process gas enters the absorber at about 185 ^{o}F, where about 90% of the H_2S and COS are removed.

The clean gas from the Benfield system is cleaned of any possible carryover of potassium salts by a two-stage water washing system. The cleaned product gas is heated and saturated at 320 ^{o}F in a shed-deck column, wherein about 90% of the heat is from raw quenched gas.

6.1.4 Tail Gas Cleanup

A modified Claus unit (CBA process) has been selected by the Artloff Corporation of Midland, Texas, for converting about 95% of the sulfur. The incinerated Claus tail gas stream is the only gaseous stream going to the atmosphere; it contains about one percent by weight of SO_2. Lockhopper gases and all other vents will be incinerated in the Claus incinerator. Solids removed in the filters should be disposed of with the gasifier ash.

6.1.5 Booster Air Compressor System

Booster Compressor. Two vertically split, centrifugal barrel-type compressors having three-stage rotors, labyrinth shaft seals, tilting-shoe journal bearings, Kingsburg-type thrust bearings, and fabricated steel casings. Bearing lubricating oil is supplied from the steam turbine driver oil system. Each compressor is rated at 6850 hp at 8000 rpm; 8600 ICFM at an inlet pressure of 224 psia and a pressure ratio of 1.72.

Booster Compressor Driver. Two single inlet, multivalve, five-stage condensing steam turbines with 4-1/2" LSB. The design operating speed is 8000 rpm; each turbine requires 58,000 lb/hr of steam at 450 psia, 581 ^{o}F from the cold reheat system.

The turbines are a single flow design exhausting to the main steam turbine-generator condenser at 2-1/2" HgA. The two drive turbines share a common oil system which supplies oil to the turbine hydraulic control systems and the drive turbine and compressor bearings. The oil system includes all required pumps, filters, coolers, reservoir, monitoring and control subsystems. Steam for the drive turbine shaft seals is supplied from the main steam turbine-generator seal steam systems.

Booster Compressor Precooler. Each of two parallel booster compressor precooler trains has two single-pass, packed head, straight tube heat exchangers. Removable tube bundles have 20 ft long, 5/8" diameter stainless stell tubes, having an effective surface area of 900 ft^2. Duty for each precooler train is approximately 20,000,000 Btu/hr.

6.2 PRIME CYCLE WATER-COOLED GAS TURBINE-GENERATOR

6.2.1 Flange-to-Flange Gas Turbine

The preliminary flange-to-flange design for the prime reference design turbine subsystem at 16:1 and 2600 °F, with water cooling and low-Btu gas fuel, is indicated in Figure 6-1. The single-shaft, three-bearing machine includes a 20-stage compressor and a three-stage, water-cooled gas turbine. The mechanical design of the compressor is similar to current General Electric Heavy Duty Gas Turbine practice in that the stacked disc concept is used. Rotor blades are retained in axial dovetails, and the discs are stacked and through-bolted by eighteen 2.5" diameter tie bolts. Included in the stackup are the front stub shaft, which incorporates the first-stage blading, and the aft stub shaft, which incorporates the 20th-stage blading. Rotor concentricity is maintained by tight rabbet fits between discs. The three gas turbine stage wheels and two spacer discs are similarly tie-bolted to forward and aft torque cones that are integral with hollow shafts which include the number 2 and number 3 bearing journals. The combination of large radii shafting with three bearings ensures a first free-free critical above the operating range.

The three gas turbine stage wheels and two spacer discs are similarly tie-bolted to forward and aft torque cones that are integral with hollow shafts which include the number 2 and number 3 bearing journals. The combination of large radii shafting with three bearings ensures a first free-free critical above the operating range.

All bearings are center-line-supported from the casings which, in turn, are center-line-supported by water-cooled casing supports on the turbine base structure. The forward support is near the combined number 1 journal and thrust bearing, and is fixed to restrict axial movement of the casing. The aft support is designed to flex to accommodate the axial movements of the casing. Air is extracted from an intermediate compressor stage for use in the labyrinth seals in each of the three bearing housings, where it prevents oil from leaking out of the bearing.

The structural casings, starting at the front of the machine are: the inlet casing with forward support provisions; the front compressor casing, which contains the inlet guide vanes, four additional rows of variable vanes, and one row of fixed vanes; a center compressor casing, which contains six rows of fixed compressor stators, as well as provisions for two stages of air extraction; the rear compressor casing, which contains the 13th-through 20th-stage fixed vanes; a compresor discharge casing with "strong-back" struts, combustor pads, and #2 bearing oil and air provisions; a combustor casing with extraction pads; turbine shell with water cooling provision; and an exhaust discharge casing.

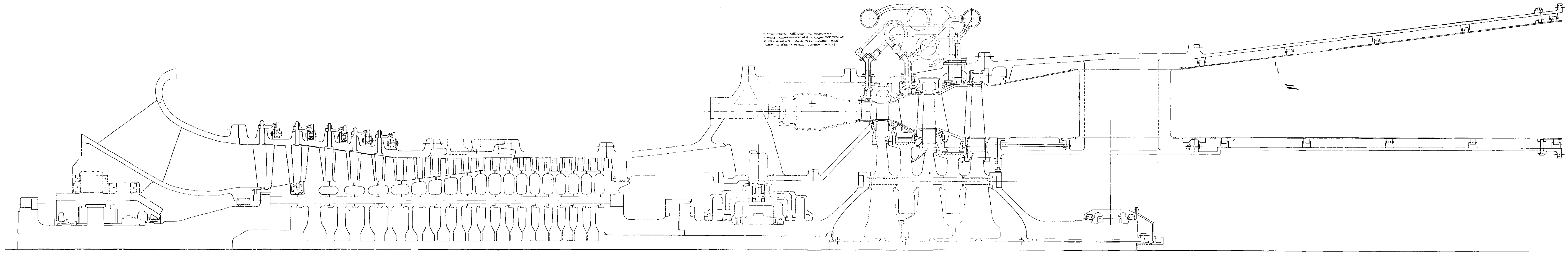

Figure 6-1. Gas Turbine Prime Reference Design

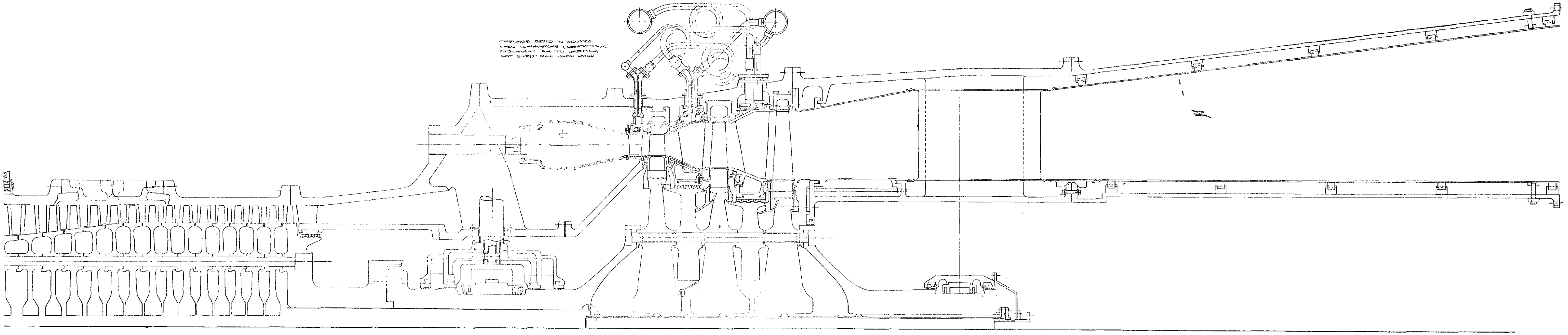

Figure 6-1. Gas Turbine Prime Reference Design

- Blading solidity based on:

  Nozzle Zweifel number = 0.6 to 0.7
  Bucket Zweifel number = 0.8 to 1.0

- Stage velocity ratio = 0.5 to 0.6
- Stage aerodynamic loading Ψp = 0.6 to 0.9
- Implementation of aerodynamic designs with mechanical designs based on parts lives as shown in Table 6-1

Table 6-1

GAS TURBINE DESIGN LIFE CRITERIA

	Parts Life (hrs)	
Nozzles	**Coal-Derived Fuels (Gas or Liquid)**	**Duty Starts**
Stage 1	41.5×10^3	1675*
2	↓	↓
3	↓	↓
Buckets		
Stage 1	83.0×10^3	3350
2	↓	↓
3	↓	↓
Shrouds		
Stage 1	41.5×10^3	1675
2	83.0×10^3	3350
3	83.0×10^3	3350
Wheels		
Stage 1	200.0×10^3	8120
2	↓	↓
3	↓	↓
Combustion Liners**	41.5×10^3	1675
Transition Piece**	41.5×10^3	1675
Exhaust Diffuser	200.0×10^3	8120

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*Based on 50% operation at base load and 50% at mid-range.

**Parts lives for combustion liners and transition pieces apply only for clean low-Btu gas. These values do not apply for dirty gases or coal-derived liquids.

For operation at 2600 °F, the efficiency of the three-stage turbine design is optimized with equal energy per stage and high root reaction, if very small tip clearance can be reliably achieved. Consideration of growth to 3000 °F, with the resultant increase in last stage loading, would lead to a somewhat lower last stage loading at the 2600 °F design point. In addition, more moderate levels of reaction, which will allow high performance levels to be achieved and maintained with less demanding tip clearances, seem a logical design selection, based on the General Electric Company's experience. For the low-Btu gas fueled machine, assuming the advanced fixed-bed fuel system, design criteria that seem viable as a result of the preliminary Phase I investigations are energy splits of about 40%, 34%, and 26% for stages 1, 2, and 3, and root reactions of about 18%, 20%, and 28%, respectively. Finalization of these design criteria during Phase II will reflect the effects of other design and operational features, such as wheel spacing, interstage passage divergence, and cooling requirements.

An important consideration in Phase I has been the performance of the gas turbine in both the entrained bed CGS-CC plant and in the CDL-CC plant based on the same design as that for the fixed-bed CGS-CC plant, except for a reduction in the first-stage nozzle area to maintain the required pressure ratio at the smaller gas turbine volumetric flows associated with the systems. A reduction in stage efficiencies results from the shift in incidence angles, the departure from a nonfree vortex design, and the increased swirl to the diffuser.

6.2.2 Hydrogen-Cooled Generator

The hydrogen-cooled turbine-generator is completely enclosed for operation with hydrogen as a cooling medium. The separately excited rotating field, driven by the steam turbine, rotates inside the stationary armature. It is supported by bearings located in end shields which form the end enclosures of the generator frame. The machine is designed to operate continuously and to give long and trouble-free life, and to provide maximum protection against damage due to abnormal operating conditions.

The stator frame is a welded structure supported on the foundation by feet attached to the sides of the frame. The end shields are bolted to the ends of the frame. The frame also serves as the support and enclosure for the hydrogen coolers. All end shields, coolers, and access holes are gasketed to prevent leakage of the hydrogen from the generator.

The stator core is made up of segmental, annealed, insulated punchings of high quality silicon steel to give minimum electrical loss. The stator core is flexibly mounted in the generator frame to isolate the effects of double-frequency vibration caused by the magnetic forces. These punchings are assembled in an interleaved manner on the key bars (ribs) and are separated into packets by space blocks to provide ventilation ducts. The punchings are stamped from thin steel sheets and contain slots for the armature bars with dovetail slots for wedges to hold the armature bars in place.

The assembled punchings are pressed and then clamped into a stiff cylindrical core by pressure applied through end flanges which are bolted over the ends of the stator key bars. Pressure is applied to the teeth by nonmagnetic steel fingers under the end flanges. In order to reduce end heating from end leakage flux and its associated electrical losses occurring at the ends of the stator core, the end packets of punchings are stepped back to increase the gap between the punchings and the rotor. The punching insulation, Santocel, is a thermo-setting varnish containing silica, which maintains its insulating value at temperatures above the normal operating range.

The hydrogen coolers are mounted vertically in the cooler towers at the four corners of the frame. Water inlet, outlet, and vent pipe connections are made externally at the bottom of each cooler.

Seals are made by gaskets between the generator frame and the coolers at the top and bottom ends of each cooler. The method of sealing is such that the water boxes and covers can be removed to clean a cooler without opening the generator hydrogen ventilation circuit.

The rotor is machined from a single alloy steel forging which has passed extensive tests to assure that the forging meets the required physical and metallurgical properties.

Longitudinal slots, machined radially in the body, contain the field coils. Additional slots, machined in the teeth, provide ventilation for the rotor body. The field coils are held in the slots against centrifugal force by metal wedges, both magnetic and nonmagnetic types being used to secure proper flux distribution. These wedges are individually fitted and driven into dovetail grooves machined in the rotor slots.

The rotor fans, provided for the ventilation of the generator, are assembled near the ends of the rotor. The rotor is cooled externally by the hydrogen flowing along the gap over the rotor surface and internally by the hydrogen which passes by the rotor end windings and through the ventilating slots in the rotor, then into the gap through holes in the ventilating slot wedges. Hydrogen passes from the gap through the openings in the stator core and then returns through the coolers to the fans.

6.2.3 Axial Flow Exhaust

The gas turbine is designed to permit axial flow of the exhaust gas from the hot gas path directly toward the HRSG without the usual right-angle turns. This design requires relocation of the electrical generator from the turbine end to the compressor end of the unit. The starting motor for the unit drives through the generator shaft to the unit shaft at the compressor end of the unit.

The advantage of this arrangement is the reduction of ducting problems which would be experienced with the higher exhaust gas temperatures in HTTT plants, as compared to STAG plants. Better proximity of the HRSG to the turbine can be obtained and ease of power island layout is facilitated.

6.2.4 Off-Base Accessory System Design

In the preliminary gas turbine accessory system designs implemented during Phase I, the modularized, highly packaged, factory assembled, skid-mounted construction concept has been retained, as indicated in Figure 6-2, which shows the arrangement of two gas turbine sets.

The gas turbine is directly connected to a hydrogen-cooled, 2-pole, 3600 rpm generator with a 0.90 power factor. As indicated, the starting means for the gas turbine-generator drives into the collector end of the generator.

Enclosures for Turbine Compartment, Load Drive Compartment, and Accessory Compartment. Standard modular designs will consist of a structural steel framework which will support the panels, roofs, and doors, will be uniform in appearance, and will be able to contain carbon dioxide if the fire protection system is activated. The maximum·size of each compartment, when assembled on its base, must be within size limitations imposed by domestic shipping and handling requirements. These compartments will provide weather protection, sound attenuation, and thermal insulation.

Enclosures for other components, such as starting means, should maintain uniformity with these criteria.

Inlet Equipment. The inlet system consists of an inlet filter house, ducting, silencing, elbow, and inlet plenum. The air inlet compartment contains inertial separator filter elements and second-stage high-efficiency dry filtration media. The inlet ducting, in addition to directing combustion air flow to the inlet plenum, also provides attenuation of the compressor blade high-frequency noises. The silencers are of baffle-type construction, and the elbow and transition sections are acoustically lined to aid in sound reduction.

Exhaust Equipment. The exhaust plenum directs the exhaust gases from the diffuser into the exhaust system in an axial direction. From the plenum, the gases pass through a transition section of the silencing section. Leaving the silencing section, the gases go through another transition section to the HRSG. The HRSG includes dampers which direct the flow either to the HRSG or to the atmosphere. The exhaust system will withstand temperatures up to 1500 ^{O}F.

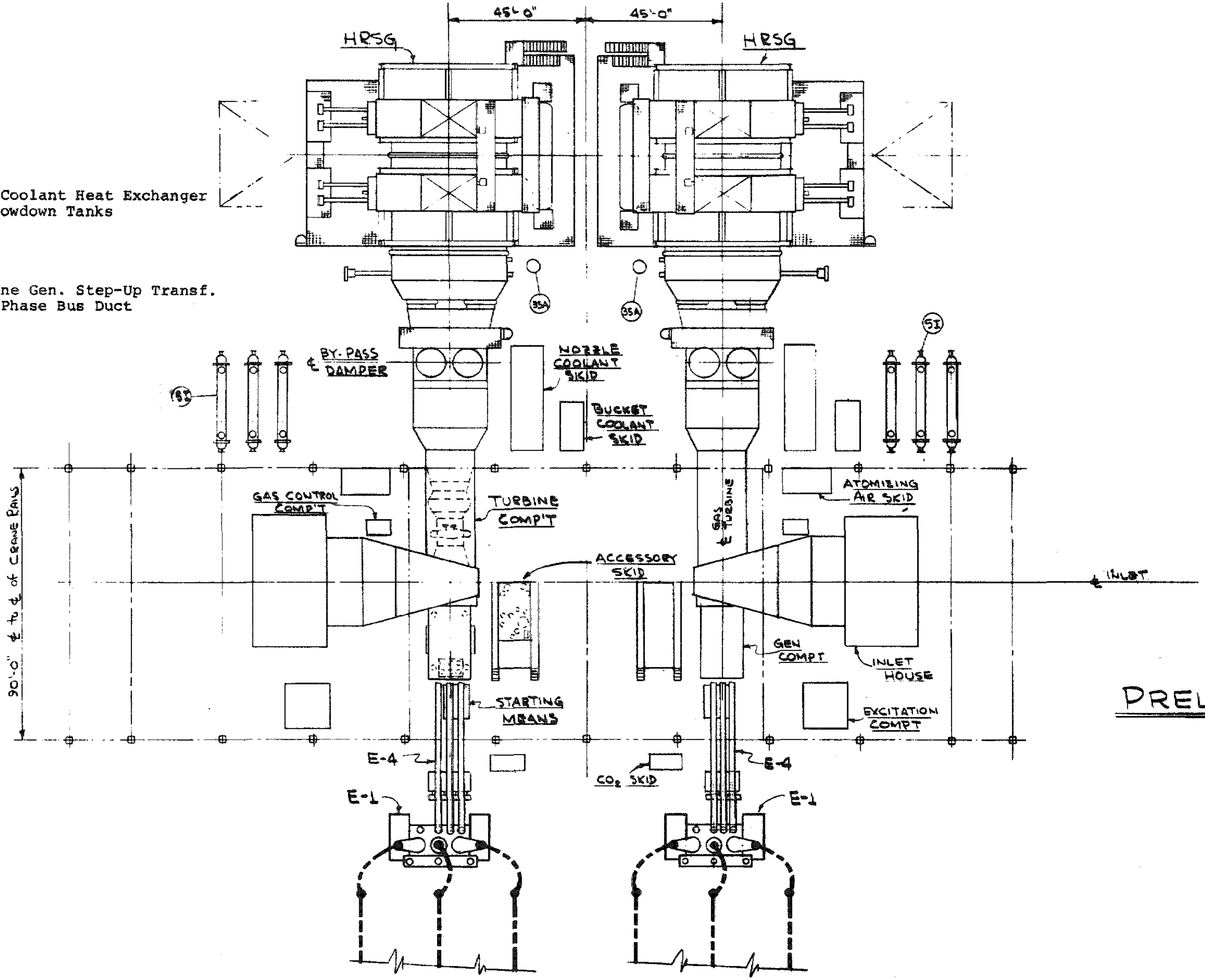
Accessory Base. The accessory base is a structural steel assembly forming a mounting platform and support for the lubrication system equipment (pumps, coolers, filters, etc), the hydraulic supply components, the control system components, the gauge cabinet, the motor control units, and the fire protection carbon dioxide supply. It also serves as the lube oil storage tank.

<u>**Mechanical**</u>

M-5I   Nozzle Coolant Heat Exchanger
M-35A HRSG Blowdown Tanks

<u>**Electrical**</u>

E-1 Gas Turbine Gen. Step-Up Transf.
E-4 Isolated Phase Bus Duct



PRELIMINARY

Figure 6-2. Gas Turbine/HRSG Area Plan-Elevation: 0'-0"

Fire Protection. Fire protection is provided to the turbine turbine enclosure, accessory compartment, and load drive compartment by means of carbon dioxide, which is stored in rechargeable, high-pressure bottles which are manifolded together and mounted on the accessory base. When activated, the system can furnish a minimum CO_2 concentration of 34% within one minute.

Lubrication System. The generator and gas turbine share a common lubrication system which utilizes a fire resistant lube fluid with the reservoir in the accessory base. Two full-capacity AC pumps, two partial-capacity DC pumps, and a DC generator seal oil pump are used. A fail-safe system arrangement is used to control header pressure, so that at no time can flow be completely cut off.

Lube oil is also supplied to the hydraulic system.

Dual water-cooled oil coolers are located on top of the accessory base.

Atomizing Air. An atomizing air system is necessary for satsatisfactory, smoke-free operation on liquid fuels. The atomizing air skid contains its own lube oil system in its steel base and supports a single-stage centrifugal compressor, with its accessories and associated piping, in addition to an air-to-water precooler. Lube oil cooling is accomplished by a separate shell and a lube oil-to-water heat exchanger. The system has an electric/pneumatic control system which monitors all critical parameters and provides permissive circuits, along with alarm and shutdown circuitry for safe operation of the equipment.

Cooling and Sealing Air. During operation of the gas turbine turbine, air is extracted from various stages of the axial flow compressor and is directed to the labyrinth seals of the three main bearings to prevent oil from leaking out of the bearings. In addition, the cooling, sealing, and extraction air is used for wheel space blockage service and compressor antistall extraction during startup, and also provides air to the gasification facility. Cooling and sealing air piping is arranged within the confines of the turbine enclosure with the exception of the piping for the antistall airflow and the gasification process airflow.

Turbine Fuel System. For the low-Btu-gas-fueled machine, #2 distillate will be used to start, warm up, accelerate, synchronize, and initially load the gas turbine in preparation for transfer to fuel gas. The #2 distillate forwarding system for this machine consists of a single forwarding skid which pumps, heats, and regulates the pressure of the fuel to the turbine, with fuel filtration at the turbine.

The low-Btu gas system requires large gas step and gas control valves which will be separately mounted in the gas compartment adjacent to the turbine enclosure. The low-Btu gas manifold is an inverted U-shaped assembly of 20" OD pipes with a single 30" OD delivery manifold at the top.

For the coal-derived liquid case, the fuel forwarding system consists of three individual off-base systems: a distillate fuel oil forwarding system, a heavy fuel oil forwarding system, and a multiple fuel filtering/selection skid to supply and control the fuels to the gas turbine.

Starting Means. The starting means base contains a large electric motor, a hydraulic torque converter, a speed increaser gear, an oil source, control devices, and associated piping. The starting means also includes a turning gear, which provides breakaway and very low speed rotation to present shaft bowing when hot. After breakaway, the starting means, driving through the generator, accelerates the turbine to firing speed and then, after a thermal soak period, to self-sustaining speed.

Water Cooling Systems. The cooling systems provide cooling of the lubricating fluid which serves the turbine, generator, and starting means, and provide cooling water for the turbine nozzles and turbine buckets. Water is also supplied to cool the hydrogen in the generator, the turbine support legs, and the flame detectors, and for the atomizing air precooler and lubrication system on the atomizing air skid.

The generator lubricant and hydrogen cooling subsystem is so configured that the cooling water solution flows first through the heat exchangers in the generator, then through the turbine support legs, flame detectors, lube oil heat exchanger, and finally the atomizing air precooler.

When water is used for nozzle and bucket cooling, the very low metal temperature (about 1000 °F) results in very high heat flux and, hence, failure of the cooling subsystem to provide an accurate flow of coolant can be expected to be catastrophic to turbine hot gas parts. Consequently, sophisticated coolant control is necessary to ensure long turbine life and operating reliability. Direct measurement of critical part temperatures as a feedback signal is not considered a viable approach, due to the large number of individually cooled parts and the difficulty of accurate temperature measurements on rotating parts on a production basis. Therefore, the cooling system controls will function primarily as flow controls. High reliability will be required in the coolant flow distribution and return to ensure that each individual nozzle and bucket receives an adequate supply of coolant.

The cooling control subsystem will consist of sensors, control devices, control valves, and electronic equipment integrated together to provide reliable coolant flow to the gas turbine. This equipment will be located on the gas turbine itself, on an off-base skid, and in the turbine control area. Control interfaces will be required with the STAG portion of the plant as well as with the gas turbine controls.

Electronic control functions will be performed within the SPEEDTRONIC control system. State points will be sensed and will interface with gas turbine sequencing permissives and protection logic in the SPEEDTRONIC.

This system will be developed and refined during Phase II, especially as a requirement for the Technology Readiness Vehicle. Computer simulation studies will be required in this Phase II development.

Compressor Extraction. In the CGS-CC plant, extraction from the compressor discharge is used to furnish air to the coal gasification plant. The extracted air is cooled before further pressurization in the booster compressor for injection into the gasifiers. Extracted air will be headered and piped to an off-base skid where the air extraction valving is located.

An overall plant control simulation study during Phase II will assist in the final definition and development of the extraction system, including the necessary modifications in the SPEEDTRONIC control system. An optional program has been proposed.

Gas Turbine Control System. A major objective of the HTTT program is to retain the operating flexibility of the General Electric Company's current STAG plants, wherein multi-gas turbine plants can be started and brought to full load under automatic control in less than one hour, from a hot standby condition. In meeting this objective, the fundamental building blocks are the gas turbine's SPEEDTRONIC control system and the overall STAG plant type of control philosophy, with suitable modifications due to the reheat steam system and process needs.

During integrated operation with the low-Btu fuel system, the gas turbine fuel control valve may be used to control the gasifier pressure level, wherein all of the available fuel gas will be utilized by the gas turbine while maintaining the gasifier at constant pressure. An alternative "turbine lead" mode permits the gas turbine to respond directly to the load change at a rate at which the fuel plant can keep pace without an excessive increase or decrease in the pressure level of the fuel plant.

Three primary control loops control the standard single-shaft gas turbine: startup, speed, and temperature. The output of each of these loops is fed to a minimum value gate, where the loop requiring the least fuel will determine fuel control voltage (VCE). This system enables a simple cycle gas turbine to be brought automatically to a full load condition. Furthermore, the General Electric Company's STAG plants, with the individual gas turbine SPEEDTRONIC control systems interfaced with steam side permissive requirements and a plant sequencer, can also be started and loaded automatically from a ready condition.

In the above system, note that a Gas Fuel Pressure Control Loop is included; a minimum value gate receives its output and the gas control voltage from the VCE splitter and allows the gas fuel control loop to utilize the available gas at a constant header pressure. During Phase II, the SPEEDTRONIC control system will be modified for this new capability, as well as for the additional functions which are required for extracting gasifier process air and achieving satisfactory operation with water-cooled nozzles and buckets. The requirements for these additional requirements are discussed in the two preceding sections on Water Cooling Systems and Compressor Extraction.

The development of the modified SPEEDTRONIC system during Phase II will be based, in part, on an overall plant control simulation. The development will also be necessary for the Test Readiness Vehicle turbine's control system.

6.3 BOTTOMING CYCLE STEAM TURBINE-GENERATOR

6.3.1 Heat Recovery System Components

The heat recovery system shall consist of the following basic components:

A. A steam generating system consisting of:

   1. Steam drum
   2. Superheater
   3. Reheater
   4. Evaporator
   5. High-and Low-Temperature Economizers
   6. Forced circulation water pump
   7. Pipes, valves, and fittings as required to make up the steam generating system

B. In the General Electric Company's conventional STAG plants, the low-level (temperature) economizer furnishes relatively high-pressure-high-temperature water to a flash tank in an amount to generate steam for the deaerating feedwater heater; this is referred to as the DASSH hot water system. In the HTTT combined cycle, a much greater quantity of low-level heat is available, and a multiple flash system is used, as previously described in Section 3, to permit the energy to be recovered at the highest practical level of efficiency.

C. The heat recovery system associated with each gas turbine shall be supplied in six main subassemblies, as required to satisfy area shipping clearances and to minimize the maximum weight to be handled during transportation and erection. These main subassemblies consist of:

   1. One box containing the reheater
   2. Steam drum
   3. Two boxes containing the heat transfer surfaces for the superheater and evaporator
   4. Two boxes containing the heat transfer surfaces for the economizers

   (The boxes in items 3 and 4 will be arranged in separate side-by-side HRSGs, receiving gas from a common duct which contains the reheater in item 1.)

Each assembly will be furnished with National Board registration of design. The design of all of the pressure parts shall comply with the requirements of the ASME Code Section I and all addenda in effect as of the date of quotation.

Each assembly will be subjected to a witnessed shop hydrostatic test at a pressure of 1-1/2 times the design pressure of the system. The final hydrostatic test of the erected and assembled components shall be by the purchaser.

The terminal, or "Field," connection points are short pipe stubs connected to the inlet and outlet headers of the economizers and the outlet headers of the superheater and reheater.

The steam generator is of the forced circulation type. It is the function of the circulating water pump to maintain a positive water flow through the evaporator section of the steam generator.

The heat transfer sections are arranged in the following order, in the direction of gas flow: reheater, superheater, evaporator, and the economizers.

The reheater and superheater sections are positioned to absorb the heat from the highest temperature gases. They consist of one or more rows of tubes, in one or multiple passes, connecting the inlet and outlet headers and specifically designed to meet the performance requirements of steam flow and reheat and superheat temperatures. Steam flow through the superheater and reheater is counterflow to the exhaust gas flow for maximum heat transfer.

A multiple row two-pass evaporator provides for unrestrained tube expansion during temperature swings through the use of free-loading return bends (U-bend-type construction) at one end of the evaporator. The U-bend design also provides balanced steam output from the parallel circuits in the evaporator by connecting the bottom row of tubes (hottest gases, hence the most steam produced) to the top row (coolest gases, hence the least steam produced), connecting the next to the bottom row to the next to the top row, etc, resulting in an evaporator with virtually the same steam production from each tube unit. Physically, the U-bend tubes are welded to two groups of larger horizontal inlet and outlet manifold headers. The inlet header is connected to the circulating pump discharge line; the outlet header is connected to the steam drum. This arrangement provides resistance to thermal shock and gives fast startup capability.

The economizer tube circuits are arranged to provide counterflow heat transfer between the water and the exhaust gas flow. Free expansion of the tubing is allowed for by the use of a serpentine-type arrangement, with the inlet and outlet headers fixed in position. Economizer heat transfer surfaces are selected to minimize steaming; excessive economizer steaming may lead to vapor locking of some of the economizer tube circuits. The connecting pipe between the steam drum and the economizer is referred to as a "Hartford Loop." It is the function of this loop to prevent water from draining out of the economizer during operation, startup, or shutdown.

The aforementioned heat transfer sections, reheater, superheater, evaporator, and high-pressure economizer form the basic steam generator. The low-pressure economizer provides hot water for the generation of low-pressure steam for the deaerator and for induction into the turbine, if available.

All heat transfer surfaces are of the extended fin type. The fins are helically wound and electric resistance-welded to the tube wall. This provides an excellent heat transfer bond between the fins and the tubes. The assembly of the tubes to return bends and headers is of welded construction, which minimizes the effects of thermal shock caused by rapid temperature swings.

The steam generator box consists of two longitudinal side plates welded to endtube support sheets to form a rigid body structure. The box is split horizontally between the economizers and the evaporator/superheater section for shipment.

The tube support sheets are drilled to provide and maintain proper spacing and support of the tubes in the various heat-absorbing tube bank sections.

All tubes extend beyond the endplates and are joined to their respective headers, which are located outside the gas path. A gas-tight enclosure is placed around each individual group of headers and tubes to prevent gas leakage and gas short-circuiting of the heat transfer surfaces.

The main feature of the tube and header construction is its ability to resist thermal shock. Tubes are strength-welded to their respective headers. The tubes rest entirely on the finned surface; thus thermal expansion of the tubes in the tube sheet holes will not wear or chafe the tube wall.

Access doors are provided to allow entry into each tube bundle assembly for visual inspection. Openings are also provided in each tube sheet to allow inspection of the tubes and sootblowers in that area.

Arms are cantilevered out from the economizer's body. The steam drum is hung from these support arms by hanger bolts. This arrangement will give sufficient flexibility to the drum so that thermal expansion of interconnecting pipe will not place undue stress on either the steam drum or the steam generator

High gas temperatures are encountered in the lower portion of the steam generator body. This region is protected by the use of internal lagging and insulation which extends upward to a height dictated by good thermal practice. It is also used to maintain the box at a temperature sufficiently high to prevent sulfur corrosion and to minimize the box temperature differential from bottom to top. In this area only, the endtube sheets are attached to the side plates for their full height. All intermediate tube sheets are attached to the side rails above the internal insulation and lagging with the lower portion free.

All steam generator components which have the ability to radiate heat are covered externally with insulation and lagging as required for comfort and safety.

Lugs are attached to the steam generator support steel at the center of its longitudinal and lateral axis. These lugs are contained in guides attached to the steam generator box. This combination of guides and lugs serves to fix the center of the steam generator box, while the body can expand in all directions without restraint.

Six support brackets are attached to the upper portion of the evaporator/superheater box section--one near each corner and one in the center of the box siderail plates. The entire steam generator system will be hung by steel rods from an independent support steel structure.

6.3.1.1 By-Pass Steam Conditioning Systems. Two by-pass steam conditioning systems, each consisting of one pneumatically operated pressure reducing valve and two atomizing-type, spray desuperheaters. The conditioning system pressure reduces and desuperheats 490,000 lbs/hr of steam at 2400 psia, 1000 °F to 250 psia, 430 °F.

6.3.1.2 HRSG Circulation Pumps

6.3.1.3 Condensate Return System

6.3.1.4 Main Steam By-Pass Valve. One motor operated by-pass valve designed to pass 490,000 lbs/hr of steam at 2400 psia, 1000 °F.

6.3.2 Steam Turbine-Generator

One 155,100 kW, 3600 rpm, tandem compound reheat, two flow steam turbine with 23" last stage buckets designed for inlet steam conditions of 2400 psig, 1000 °F, and exhausting at 2-1/2" HgA.

One 191,500 kVA (at 30 psig hydrogen pressure), 0.85 pf, three phase, 60 Hz, 13,800 volt, 0.58 short circuit ratio synchronous generator with corner-mounted coolers designed for 95 °F cooling water with one suitably rated static excitation system. The following will be provided with this equipment:

A. Steam Turbine

1. Emergency stop valve
2. Overspeed governor
3. Shaft packing seal system

4. Lubrication supply unit

B. Generator

1. One-piece stator frame

2. Temperature detectors

3. Hydrogen cooling system

4. Seal oil system

5. One excitation system

6. One surge protection and neutral grounding cubicle

6.3.3 Major Mechanical Auxiliaries

The following will be provided under this category and are described in detail below.

6.3.3.1 Mechanical Auxiliary Controls

A. General

Controls are provided for the following major steam cycle auxiliary subsystems:

1. Turbine by-pass
2. Hotwell
3. Condensate flow
4. Boiler feedpump
5. Deaerator

The controls are arranged to provide a centralized analog control of loops with manual backup similar to that of the STAG plant. Annunciation and protective override and trip functions are provided where required, for dependable and safe operation.

The controls consist of field devices which are wired to a termination area on a one-signal conditioning and protective relay cabinet. The cabinet is described as the UNIT AUXILIARY CONTROL (UAC) cabinet and, at 68" wide x 36" deep x 90" high, is dimensionally suitable for alignment with the UBC and EHC cabinets. The UAC cabinet may be located in the back row of the control room or in an adjacent electronics area, since no operator interface is required.

Operator interface control equipment such as indicators, recorders, and control stations are located on the STATION CONTROL CONSOLE and the STATION CONTROL PANEL. These devices are connected to signal conditioning modules located within the UAC by premade cables.

B. Control Subsystems Descriptions

Turbine By-Pass. The turbine by-pass subsystem consists of a steam pressure reducing and desuperheating station, along with the associated measurement, control, and protective devices. During STAG startup, the main steam header pressure is controlled by passing steam through the pressure-reducing valve and desuperheating this steam for admission to the condenser.

The main steam pressure control loop consists of a header pressure transmitter and a controller which modulates the pressure-reducing control valve and holds header pressure at a fixed setpoint value; this permits the steam turbine to achieve roll-off and initial loading. When the steam available to the turbine by-pass subsystem is minimized, the steam turbine assumes pressure control and the pressure reducing valve is ramped closed. A turbine by-pass discharge pressure transmitter and a controller are provided to limit steam pressure at the condenser inlet. They override the primary pressure control through an auto selector system.

A desuperheating control loop, consisting of a thermocouple and a controller, modulates the desuperheating water spray valve and controls steam temperature at the condenser inlet.

Turbine by-pass trips are provided for high discharge pressure, high discharge temperature, and low Hotwell vacuum.

Control panel indications of inlet pressure, discharge pressure and temperature, and pressure reducing valve position are provided, as well as control stations for the pressure reducing and spray water control valves.

Hotwell. The Hotwell subsystem consists of a two-mode, gravity and forced condensate makeup system, including a makeup pump and two makeup control valves. A system to dump condensate through two control valves located at the outlet of the condensate pumps is also provided. Measurement, control, and protective devices constitute the balance of the subsystem.

The primary level control of the twin Hotwells consists of a displacement-type level transmitter in each well. The level signals from the two Hotwells are highly selected and used with the makeup and dump controllers. The two split-ranged makeup control valves are modulated by the makeup controller and maintain Hotwell level by admission of condensate by gravity feed from the condensate storage tank. Transient requirements for condensate in excess of the gravity feed capability will cause level to drop. Low Hotwell level switches will start the forced makeup pump and override the makeup valves open, quickly restoring the level to the normal range.

Transient conditions that cause the Hotwell level to rise will cause the dump controller to modulate the split-ranged dump control valves. These valves control Hotwell level by dumping condensate back to the storage tank. Overrides of the makeup and dump valves are provided at high Hotwell levels.

Redundant and backup redundant trips of the steam turbine are provided at very high Hotwell levels. Redundant trips of the condensate pumps are provided at very low Hotwell levels. Low vacuum in the Hotwell is annunciated.

Recording of Hotwell level; indication of Hotwell level pressure and temperature, and control stations for the makeup and dump valves are provided on the control panel.

Condensate Flow. The condensate flow subsystem provides for condensate pump startup and monitoring and for recirculation of condensate to the condenser, to provide for the minimum flow requirements of the gland seal condenser and the condensate pumps.

The primary control senses condensate flow across a nozzle and modulates the recirculation control valve to maintain a minimum of approximately 20% of rated condensate flow through the condensate pumps and gland seal condenser.

Pressure switches are provided to autostart the alternate condensate pump if header pressure drops below the design level.

Control panel indication of condensate pump discharge pressure and condensate flow are provided, as well as a control station for the recirculation control valve.

Boiler Feedpump. The boiler feedpump subsystem consists of the two boiler feedpumps and minimum flow recirculation, as well as the associated measurement, control, and protective devices.

The primary control consists of flow measurement transmitters across orifice assemblies in series with each of the boiler feedpumps. Each flow transmitter is connected to a controller which modulates a control valve. The valve recirculates feedwater to the deaerator. Minimum boiler feedpump flow is maintained in this manner under startup conditions. A low feedwater pressure switch and individual high boiler feedpump flow switches autostart the second pump when required.

The boiler feedpumps are tripped if the feedwater flow drops below the minimum recirculation flow requirement.

Control panel indication of individual boiler feedpump flow and main feedwater header pressure are provided as well as control stations for the recirculation flow control valves.

Deaerator. The deaerator subsystem is a feedwater heater with the associated measurement, control, and protective devices used to support the feedwater requirements of the boilers.

The two controlled variables are the deaerator pressure and the storage tank level. Deaerator pressure is controlled to maintain the feedwater temperature required by the HRSGs. During plant startup, the steam required to maintain pressure is supplied from the auxiliary boiler through the pegging steam system. A deaerator pressure transmitter and controller admit sufficient steam to maintain pressure. As the plant output increases, feedwater is circulated from the deaerator storage tank, through the low-pressure economizer sections of the HRSGs to provide steam for deaerator pressure control.

A three-element control with single-element startup is used to maintain deaerator storage feedwater level. During startup the control modulates the main condensate control valve in response to storage tank level only. At higher loads, the condensate control valve is modulated based on the match between feedwater demand and condensate flow, with a trim for the storage tank level.

The condensate pump for makeup to the deaerator is started by a low-level switch while at very low levels; the boiler feedpumps are tripped. At very high levels, the motorized dump valve drains feedwater to the condenser and the main condensate control valve is overridden and closed.

Control panel recording of deaerator level and condensate and feedwater flow are provided. Indication of condensate flow, feedwater flow, storage tank level, deaerator pressure, and storage feedwater temperature are provided, as well as control stations for the pressure control and condensate flow control valves.

Condenser and Accessories. One single-shell, single-stage, two-pass condenser with divided water boxes. The condenser has 135,450 ft^2 effective surface area, consisting of 16,114 x 32 ft long, 7/8" O.D., 18 BWG tubes. The shell, water boxes, tube supports, and tube sheets are fabricated from ASTM 285 steel; the condensing tubes are 90/10 Cu Ni. 105,800 GPM of circulating water are required at a 86 °F inlet temperature, 1717 °F rise, 7.0 ft/sec tube velocity and 85% cleanliness factor. Design operating pressure is 2-1/2" HgA, with a 5.0 °F approach.

Vacuum Pump. Two two-stage, hydraulic-type vacuum pumps. The pump has cast iron construction, is fitted with a carbon steel shaft, and is directly connected through a fast gear-type flexible coupling to a 125 hp motor. Rated holding capacity at 2.5" HgA is 30 scfm and hogging capacity at 10" HgA is 600 scfm. 125 hp TEFC induction motor, 590 rpm, 600 V, 60 cycles.

Condensate Pump. Two full-capacity, three-stage, canned, vertical condensate pumps with water-lubricated bearings and packed stuffing boxes. Pump has carbon steel barrel and head bronze impellers, cast iron bowls, and stainless steel line shaft and sleeves. Pump is rated at 2450 GPM at a 200 ft TDH, 5 ft NPSHA, and 109 °F operating temperature. Vertical, solid-shaft, electric motor driver is connected to pump top shaft through a rigid, adjustable coupling. Motor is rated at 150 hp at 1760 rpm, 460 V, 3pH, 60 Hz.

Condensate Makeup Pump. Two full-capacity, horizontally split, single-stage, centrifugal condensate makeup pumps with double-suction impellers, packed stuffing boxes, and flexible pump motor couplings. Pump has cast iron casing, bronze impeller, and stainless steel shaft and sleeves. Design performance is 440 GPM at a 250 ft TDH and an operating temperature of 80 °F. Electric motor driver is rated at 40 hp at 1750 rpm, 460 V, 3pH, 60 Hz; motor enclosure is open splashproof design.

Boiler Feed Pump. Two full-capacity horizontal, multistage, double-case barrel-type, centrifugal pumps; each pump rated at 2600 GPM at 7250 ft TDH, with a suction temperature of 222 °F. Each pump has chrome-steel casing, case wearing rings, impeller, and shaft. Pumps are provided with Kingsbury-type thrust bearing, sleeve-type radial bearings, and provision for bearing thermocouples and vibration probes. Lubrication for pump and motor bearings is provided by a pump lubricating oil system which includes main oil pump, auxiliary pump, oil coolers, filters, reservoir, and monitoring and control system. Electric motor driver is rated at 6000 hp at a synchronous speed of 3600 rpm, 4160 V, 3 pH, 60 Hz.

Deaerator. One full-sized, 8 ft diameter by 27 ft long, horizontal tray-type deaerator with an integral spray-type vent condenser and 12 ft diameter by 80 ft long horizontal storage tank. Design operating pressure is 18 psia, with a total feedwater outflow of 2,672,000 lbs/hr. Storage tank and deaeration shell are ASTM 285 carbon steel; deaerator internals are stainless steel. Design pressures for deaerator and storage tank are 50 psia and full vacuum.

Deaerator Makeup Pump. Two full-capacity, horizontally split, single-stage, centrifugal deaerator makeup pumps with double suction impellers, packed stuffing boxes, and flexible pump motor coupling. Pump has cast iron casing, bronze impeller, and stainless steel shaft and sleeve. Pump design point performance is 950 GPM at 150 ft TDH, at an operating temperature of 80 °F. Pump design pressure is 50 psig. Electric motor driver is rated at 50 hp at a synchronous speed of 1800 rpm, 460 V, 3 pH, 60 Hz motor enclosure is open splashproof.

Economizer Circulation Pump. Two full-capacity, horizontal, radially split, single-stage, double-suction, center line-supported centrifugal pumps with packed stuffing boxes and flexible pump motor coupling. Pump design point performance is 1920 GPM at 325 ft TDH, at 222 °F. Electric motor driver is rated at 250 hp at 1750 rpm, 480 V, 3 pH. 60 Hz.

Flash Tanks. Three carbon-steel process flash tanks designed to produce an outgoing steam moisture content not to exceed 1/2%; design retention time is one minute.

The low-pressure flash tank is designed for a total inflow of 1,562,000 lbs/hr at a 30 psia operating pressure, has a 78" I.D., is 252" seam to seam, and is rated 60 psig and full vacuum.

The intermediate-pressure flash tank is designed for a total inflow of 1,653,000 lbs/hr at a 70 psia operating pressure. It has a 60" I.S., is 336" seam to seam, and is rated at 100 psig and full vacuum.

The high-pressure tank is designed for a total inflow of 99,360 lbs/hr at a 160 psia operating pressure. It has a 30" I.D., is 126" seam to seam, and is rated at 200 psig and full vacuum.

6.4 BALANCE OF PLANT SYSTEMS

6.4.1 Water Supply

Water Supply Pumps. Two full-capacity, vertical wet pit, single-stage pumps with water-lubricated open lineshaft semi-enclosed mixed flow impeller, and packed stuffing box. Pump has cast iron bowls, bronze impeller, stainless steel shafting, and rigid steel coupling. Pump design performance point is 4500 GPM at 10 ft. Vertical, solid shaft electric motor driver is rated at 150 hp at 1170 rpm, 480 V, 3pH, 60 Hz.

Service Water Pumps. Two full-capacity, horizontally split, double-suction, single-stage centrifugal pumps with packed box, flexible pump motor coupling, and grease-lubricated antifriction bearings. Pump has cast iron casing, bronze impeller, wearing rings and shaft sleeves, and steel shaft. Pump design point performance is 4200 GPM at 200 ft TDH. Electric motor driver is rated at 300 hp at a synchronous speed of 1200 rpm, 4160 V, 3 pH, 60 Hz; motor enclosure weatherproof.

Potable Water Pumps. Two full-capacity, horizontal, centrifugal pumps having a 100 GPM capacity at a 120 ft TDH. Pump construction with cast iron casing, bronze impeller and wearing rings, stainless steel shaft and sleeves. Electric motor driver rated at 5 hp, 3600 rpm, 480 V, 3 pH, 60 Hz.

Raw Water Storage Tank. One carbon steel, 100 ft diameter raw water storage tank with a 3,200,000 gallon storage capacity, including 200,000 gallons dedicated fire water storage.

Demineralized Water Storage Tank. One carbon steel, 80 ft diameter demineralization water storage tank with a storage capacity of 1,300,000 gallons. Suitable corrosion allowance is included in plate thickness.

6.4.2 Water Treatment System Equipment

Cold Lime Softener

Influent capacity	4440 gpm
Size	75' diameter by 19' sidewall
Base	Concrete pad
Internals	Rake rake drive, half-bridge, center feedwell and agitator

Lime Storage Silo

Size	12' diameter by 25' sidewall
Capacity	60 tons
Feed system	Two-weigh belt type
Material	Carbon steel

Lime Slurry Tank

Size	7' diameter by 6' sidewall
Capacity	1700 gallons
Material	Carbon Steel
Design Pressure	Atmospheric
Other features	Agitator required

Lime Slurry Pumps

Type	Horizontal motor driven
Flow	80 gpm
Differential pressure	50 psi
Motor	5 hp

Coagulant Storage Silo

Size	12' diameter by 19' sidewall
Capacity	80 tons
Feed system	Screw type
Material	Stainless steel

Coagulant Solution Tank

Size	4' diameter by 5' sidewall
Capacity	450 gallons
Material	Stainless steel
Design pressure	Atmospheric
Other features	Agitator required

Coagulant Solution Pump (2)

Type	Horizontal, motor driven
Flow	5 gpm
Differential pressure	15 psi
Motor	0.25 hp

Polymer Tank

Size	7' diameter by 6' sidewall
Capacity	1700 gallons
Material	Carbon steel
Design pressure	Atmospheric
Other features	Two-speed agitator required

Polymer Solution Pump

Type	Horizontal, motor driven
Flow	3 gpm
Differential pressure	15 psi
Motor	0.25 hp

Clarifier Sludge Pit

Size	10' x 10' x 8' deep
Capacity	6000 gallons
Material	Concrete
Other features	Agitator required, construction probably below grade

Clarifier Sludge Pump (2)

Type	Vertical, motor driven
Flow	200 gpm
Differential pressure	25 psi
Motor	5 hp

Clear Well

Size	40' diameter by 20' sidewall
Capacity	18,000 gallons
Material	Carbon steel
Design pressure	Atmospheric

Cooling Tower Makeup Pump (2)

Type	Horizontal, motor driven
Flow	2500 gpm
Differential pressure	20 psi
Motor	50 hp

Cooling Tower Acid Supply Pump (2)

Type	Metering pump with motor
Flow	4 gph
Differential pressure	15 psi
Motor	0.25 hp

Corrosion Inhibitor Pump (2)

Type	Metering pump with motor
Flow	1 gph
Differential pressure	15 psi
Motor	0.25 hp

Chlorination System

Type	Package unit with chlorine evaporator and injector unit
Capacity	8000 pounds per day
Other features	Skid mounted and preassembled

Utility Water Pump (2)

Type	Horizontal, motor driven
Flow	400 gpm
Differential pressure	50 psi
Motor	20 hp

Demineralizer Supply Pump (2)

Type	Horizontal, motor driven
Flow	1340 gpm
Differential pressure	150 psi
Motor	175 hp

Pressure Filter (5)

Size	12' diameter by 6' sidewall
Material	Carbon steel
Design pressure	150 psi

Potable Water Storage Tank

Size	8' diameter x 9' sidewall
Capacity	3300 gallons
Material	Lined carbon steel or aluminum
Design pressure	Atmospheric

Potable Water Supply Pump (2)

Type	Horizontal, motor driven
Flow	100 gpm
Differential pressure	50 psi
Motor	5 hp

Ion Exchange Vessels (4 - 2 cation and 2 anion)

Size	11'-6" diameter by 8' sidewall
Material	Lined carbon steel
Design pressure	150 psi

Mixed-bed Polisher Vessels (2)

Size	8' diameter by 8' sidewall
Material	Lined carbon steel
Design pressure	150 psi

Filter Backwash Pump (2)

Type	Horizontal, motor driven
Flow	1100 gpm
Differential pressure	25 psi
Motor	hp

Regeneration Pump (2)

Type	Horizontal, motor driven
Flow	1200 gpm
Differential pressure	50 psi
Motor	60 hp

Mixed-bed Air Blower

Capacity	400 cfm
Differential pressure	10 psi
Motor	25 hp

Sulfuric Acid Day Tank

Size	5' diameter by 5' sidewall
Capacity	700 gallons
Material	Carbon steel
Design pressure	Atmospheric

Sulfuric Acid Supply Pump (2)

Type	Horizontal, motor driven
Flow	20 gpm
Differential pressure	15 psi
Motor	0.5 hp

Sulfuric Acid Regeneration Pump (2)

Type	Metering pump with motor
Flow	4 gpm
Differential pressure	30 psi
Motor	0.25 hp

Caustic Day Tank

Size	6' diameter by 7' sidewall
Capacity	1400 gallons
Material	Carbon steel
Design pressure	Atmospheric

Caustic Supply Pump (2)

Type	Horizontal, motor driven
Flow	40 gpm
Differential pressure	15 psi
Motor	0.5 hp

Caustic Regeneration Pump (2)

Type	Metering pump with motor
Flow	8 gpm
Differential pressure	30 psi
Motor	0.25 hp

Blowdown Filter (2)

Size	10' diameter by 6' sidewall
Material	Carbon steel
Design pressure	75 psi

Chromate Recovery Feed Pump (2)

Type	Horizontal, motor driven
Flow	228 gpm
Differential pressure	100 psi
Motor	25 hp

Chromate Recovery Ion Exchange Column

Size	5' diameter
Material	Lined carbon steel
Design pressure	125 psi

Sulfuric Acid Day Tank

Size	2'-6" diameter by 5' sidewall
Capacity	180 gallons
Material	Carbon steel
Design pressure	Atmospheric

Sulfuric Acid Regeneration Pump (2)

Type	Metering pump with motor
Flow	1 gph
Differential pressure	30 psi
Motor	0.25 hp

Caustic Day Tank

Size	2'-6" diameter by 5' sidewall.
Capacity	180 gallons
Material	Carbon steel
Design pressure	Atmospheric

Caustic Regeneration Pump (2)

Type	Metering pump with motor
Flow	1 gph
Differential pressure	30 psi
Motor	0.25 hp

Trash Racks

Traveling Water Screen

Potable Water Chlorinater

Condensate Polisher. One precoat-type, full-flow condensate polisher designed for 2200 GPM at 109 °F. Polisher includes two 100% deionizer tanks with wound nylon retaining elements, hold pumps, one precoat tank with agitator, precoat pump, control valves, water and air pressure control stations, control panels, interconnecting piping, and monitoring systems.

Bucket Coolant Polisher. One precoat-type, full-flow bucket coolant polisher designed for 300 GPM at 109 °F. Polisher includes two 100% deionizer tanks with wound nylon retaining elements, hold pumps, one precoat tank with agitator; precoat pumps, control valves, water and air pressure control stations, control panels, interconnecting piping, and monitoring systems. Entire system is skid-mounted.

Bucket Coolant Heat Exchanger. Three half-capacity bucket coolant heat exchangers, having removable tube bundles with 5 ft long, 5/8" O.D. stainless steel tubes. Design duty for each heat exchanger is approximately 2,320,000 Btu/hr.

6.4.3 Air Systems

Plant Service Air Compressor (1)

Single-stage, water-cooled, rotary screw-type compressor
Capacity-750 SCFM at 100 psig
Supplied as skid-mounted package including:
  Inlet filter and silencer
  Aftercooler and separator
  Receiver
  Interconnecting piping, and valves
  Instrumentation, capacity control, and control panel
  Motor (200 hp)

Instrument Air System

Instrument Air Compressor (2)

Single-stage, double-acting, water-cooled
reciprocating compressor, nonlubricated-type
Capacity - 400 SCFM at 100 psig discharge
Supplied as a skid-mounted package, including:
  Inlet filter and silencer
  Aftercooler and separator
  Receiver
  Interconnecting piping and valves
  Instrumentation, capacity control, and control panel
  Motor (100 hp)

Instrument Air Dryer (2)

Dual-type (two desiccant towers) air dryer with
  reactivation heaters
Capacity-400 SCFM at 100 psig and 100 °F inlet temperature
Design atmospheric dew point of minus 40 °F
Skid-mounted with interconnecting piping, valves, wiring,
  and automatic control

Prefilter (2)

Capacity - 400 SCFM at 100 psig

Afterfilter (2)

No particles greater than 10 microns
Capacity - 400 SCFM at 100 psig

Ventilation and Air Conditioning

Administration Building

Central air conditioning system

Mechanical refrigeration:		
DX system		80 tons
Compressor		100 hp
Condenser		15 hp
Air supply system:		25,000 cfm
1000 MBH heating coil, steam		
20 hp air handling unit with 1000 MBH steam heating coil, DX coil, and filters		
10 hp return - exhaust fan		
Toilet exhaust system	2 at	3/4 hp each
Equipment room exhauster		2 hp
Equipment room heater		10 kW

Warehouse, Shop and Laboratory

Package air conditioner:		12 ton
Compressor		15 hp
Condenser		3 hp
Supply fan		3 hp
Miscellaneous exhaust fans	5 at	2 hp each
Unit heaters	5 at	60,000 Btu/hr each
Unit ventilator		15,000 cfm
and filter fan		5 hp
and heater		300,000 Btu/hr

Water Treatment Building

Heat and vent only

Roof ventilators	2 at	10,000 cfm, 5 hp each
Unit heaters	10 at	100,000 Btu/hr each

Steam Generator Building

Powered ventilators	10 at	30,000 cfm each, 7 1/2 hp each
Miscellaneous exhausters	4	3 hp each
Unit heaters	35 at	200,000 Btu/hr each
Package air conditioner		3 tons
Compressor		5 hp
Fan		2 hp

Gasification Building (46,000 hp)

Powered ventilators	20 at	40,000 cfm each
Fan		10 hp
Miscellaneous	6 at	3 hp each
Unit heaters	50 average	250,000 Btu/hr

Maintenance Shop and Garage

Exhausters	4 at	3 hp each
Exhausters	2 at	1 hp each
Unit heaters	4 at	50,000 Btu/hr
Package air conditioner		3 ton (5 hp)

Chlorinator Building

Exhaust fan for 5-minute air change rate		
Unit heaters	5 at	30,000 Btu/hr each

Crushing Building

Heaters	10 at	250,000 Btu/hr

6.4.4 Auxiliary Boiler

Auxiliary Boiler (2)

Capacity-55,000 lb/hr of saturated steam at operating pressure of 150 psig
Fuel - Number 2 distillate oil
Feedwater temperature - 250°F
Packaged type, including the following:
  Economizer
FC fan (top-mounted)
Flues to the stack
Instrumentation and controls for automatic operation
Control panel
Insulation and lagging

Fuel Oil Day Tank (1)

Vertical, cylindrical tank, flat top and bottom
Capacity (each pump) 1,200 gph at 150 psig with duplex strainer, instrumentation, pressure regulator, and piping.

Light Fuel Oil Pump Set (1)

Duplex-type skid-mounted, packaged assembly
Capacity (each pump) 1,200 gph at 150 psig with duplex strainer, instrumentation, pressure regulator, and piping

Blowdown Tank (1)

Vertical, cylindrical tank, 3 ft diameter, 4 ft SS
Design pressure - 200 psig,
Design temperature - 388°F
Material - carbon steel
ASME, Section VIII

Deaerator - Feed Pumps Package (1)

Capacity - 125,000 lb/hr
Storage capacity - approximately 2,300 gallons
Operating pressure - 15 psig maximum
With three (3) feedwater pumps, each for 135 gpm at 450 ft (40 hp)
Complete engineered package assembled on a common base, including interconnecting piping, valves, instruments, steam pressure regulating valve, two feedwater regulating valves, makeup water regulating valve, controls, wiring, and insulation

Chemical Ball Feeder (1)

For injecting chemicals into auxiliary boiler feedwater
Capacity - 60 balls
Design pressure - 300 psig

Stack (1)

Steel stack with necessary supporting structure
6" diameter, 150' high

Condensate Return Unit (4)

Condensate collection tank and two (2) condensate return pump units on common steel base, each pump 30 gpm with discharge pressure 60 psig
Motor - 2 hp
With pump control, interconnecting piping and valves, pressure and level gauges, and insulation

Condensate Return Unit (1)

As above but with pump capacity 20 gpm
Motor - 2 hp

Condensate Return Unit (3)

As above, but with pump capacity 10 gpm
Motor - 1 hp

6.4.5 Emergency Diesel Generator

One 800 kW, 480 V, 3 ph, 60 Hz, 4 wire, emergency generator driven by a 12 cylinder, 1150 hp, 1800 rpm diesel engine

The system includes a distillate fuel system with fuel pumps and priming system; lube oil system; engine cooling system with expansion tank, automatic temperature control system, and heat exchanger; and automatic starting system. Engine is equipped with immersion heater for rapid start capability.

6.4.6 Waste Heat Rejection

Cooling Tower

Mechanical draft, wet-type, fire retardant material

Design heat load	10.12×10^8 Btu/hr
Wet bulb temperature	76 °F
Cold water temperature (Approach 10° F)	86 °F
Cooling water temperature range	17.7 °F
Cooling water flow	114,000 gpm
Eight cells, power requirement for fans	1600 hp (approximately)

Circulating Water Pump (3)

Vertical, wet pit-type, motor-driven

Flow	60,000 gpm
TDH	75 ft
Motor	1500 hp

Support Systems Traveling Screen (3)

Motor operated, wire cloth with 3/8" square openings, 2' wide

Flow	2450 gpm
Submerged area	approximately 40 square feet
Motor	1 hp

Raw Water Pump (3)

Vertical, wet pit type, motor-driven

Flow	2450 pgm
TDH	100 ft
Motor	100 hp

Cooling Tower Makeup Pump (2)

Included Under Water Treatment Data.

Auxiliary Cooling Water Pump (3)

Vertical, in-line, double suction, motor-driven

Flow	4,500 gpm
TDH	150 ft
Motor	250 hp

6.4.7 Distillate Fuel Unloading - One distillate fuel unloading station with pumps, heaters, and metering station.

6.4.8 Miscellaneous Fire, Cranes, Tanks, Etc.

Fire Pump - Electric Motor-Driven (1)

Vertical, wet pit-type fire pump, rated 2,000 gpm at 150 psi
Under the overload condition the pump shall deliver 3,000 gpm at 98 psi
Motor - 250 hp

Fire Pump - Diesel Engine-Driven (1)

Vertical, wet pit-type fire pump, rated 2,000 gpm at 150 psi
Under the overload condition the pump shall deliver 3,000 gpm at 98 psi
Diesel engine shall include hot start engine preheater, fuel system with fuel tank for minimum of 8 hours of engine operation, cooling water system, muffler, batteries, battery chargers, and manual controller
(Approximately 300 hp engine)

Hose Reel Stations (50)

With 100 ft of 1-1/2 in. rubber-lined, synthetic fiber-covered hose on a reel and a stream-fog nozzle

Fire Detectors (200)

With local audible alarms and with alarm and readout in control room

Manual Fire Alarm Station (50)

With local audible alarm and alarm in the control room

Fire Extinguisher (150)

Type ABC-28A-80BC

6.5 ELECTRICAL AUXILIARY SYSTEM

Station Auxiliary Transformers (2)

12,000/16,000/20,000, OA/FA/FOA, oil-air/forced air/forced oil-air-cooled, 55 °C, 13.8/4.16 kV transformers which will have standard low-voltage no-load taps 2-2.5% above and 2-2.5% below rated 4.16 kV, bushing CTS (6), isolated phase bus duct flanges for 13.8 kV and nonsegregated phase bus duct flanges for 4.16 kV connections, winding temperature equipment, and fault pressure relay.

Station Startup Transformer (1)

Gas Turbine Auxiliary Transformers (2)

1000/1250 kVA, OA/FA, 55°/65 °C, 13.8 kV - 480 V, 3 Ø, 60 Hz

4.16 kV Metal Clad Switchgear

One lineup of outdoor protected isle vertical-lift magne-blast metal clad switchgear rated 350 MVA. This lineup will include four transformer secondary breakers (2 aux., 2 start-up) (3000 A), one bus tie breaker (3000 A), 14 transformer primary feeders (1200 A), 20 induction motor feeders (1200 A), 3000 A aluminum bus, incoming line PT and metering compartments, transfer truck and test cabinet.

Cooling Tower Substation (1)

Each transformer rated at 1500/1932 kVA, OA/FA, 55°/65°C, 416-480 V, 3 Ø, 60 Hz
One set of 480 volt switchgear
One set of motor control centers

Coal Handling Substation (2)

Each transformer rated at 1500/1937 kVA, OA/FA, 55°/65 °C, 416-480 V, 3 Ø, 60 Hz
One set of 480 volt switchgear
One set of motor control centers

Gasification Substation (1)

Each transformer rated at 2000/2576 kVA, OA/FA, 55°/65 °C, 4160 V, 3 Ø, 60 Hz
One set of 480 volt switchgear
One set of motor control centers

Coal Thawing Substations (3)

Each transformer rated at 3000 kVA, OA, 65 °C, 4160 - 480 V, 3 Ø, 60 Hz
One set of 480 volt switchgear
One set of motor control centers

Station Water Substation (1)

Each transformer rated at 1500/1932 kVA, OA/FA, 55°/65 °C, 4160-480 V, 3 Ø, 60 Hz
- One set of 480 volt switchgear
- One set of motor control centers

Gas Cleanup Substation (1)

Each transformer rated at 2000/2576 kVA, OA/FA, 55°/65°C, 4160-480 V, 3 Ø, 60 Hz
- One set of 480 volt switchgear
- One set of motor control centers

Gas Turbine Auxiliary Standby Substation (1)

Gas Turbine Auxiliary Substation (2)

Transformers, switchgear, and motor control centers

Plant and Steam Turbine Auxiliary Substation (1)

Steam Turbine and Plant Load Center Unit Substation

One secondary selective load center unit substation, consisting of: two incoming 4.16 kV line sections, two oil-filled transformers, and one line-up of 480 V low-voltage switchgear. This load center unit substation includes:

- Two 4.16 kV air-filled incoming line units, cable connected, with air interrupter switch
- Two 4.16 kV transition units to transformer
- Two 2000/2500 kVA 4.16 kV-480V OA/FA oil-filled transformers connected to the low voltage switchgear lineup; transformer equipped with winding temperature equipment fault pressure relays
- One line-up of 480 V metal-enclosed switchgear, containing the following equipment:
  - Two PT auxiliary units
  - Two Type AK 75 incoming breakers
  - One Type AK 75 tie breaker
  - Ten Type AK 50 motor starter breakers
  - Four Type AK 50 feeder breakers
  - CT, instrumentation metering, and control equipment

480 V Motor Control Centers

Steam Turbine and Plant 480 V Motor Control Center

Two NEMA Class II, Type B, motor control centers, in NEMA I enclosure, gasketed door, 1200 A aluminum mainbus (300 A vertical). Each of the two motor control centers will include 17 size 1, six size 2, seven size 3, and three size 4 FVNR combination motor starters, 10 feeder breakers, two 240/120 V panelboards, two 480 V-240/120 V dry-type transformers, and necessary instrumentation, metering, and control.

Essential Bus (1)

6.6 INTEGRATED PLANT CONTROL--PLANT CONTROL ROOM

One Station Control Panel

Two Gas Turbine/HRSG Control Panels

Two Fuels Plant/Gas Turbine Control Panels

One Station Control Console for Plant Operation

One Plant Sequencer

Two Gas Turbine-Generator Control Panels Incorporating Speedtronic Control and Protection System

Two HRSG Control Cabinets

14 Gasifier Control Panels

Two Low-Btu Gas Cleanup System Control Panels

One Steam Turbine Electro-Hydraulic Control Cabinet

One Environmental Standards Monitoring Cabinet

6.7 ELECTRICAL POWER SYSTEM

6.7.1 Gas Turbine Generator Step-Up Transformers. Two 180,000 kVA/202,000 kVA FOA, forced oil/forced air-cooled, forced oil-to-air, 55 °C/65 °C, 230 kV/13.1 kV, generator step-up transformers with standard low voltage no-load taps 2-2.5% above and 2-2.5% below rated 13.1 kV, bushing CTS (6) 230 kV surge arrestors (180 kV rating): (3) bracket-mounted on tank, transformer low-voltage isolated phase bus duct flanges (13.1 kV wdg.), winding temperature equipment, and fault pressure relay.

6.7.2 Steam Turbine-Generator Step-Up Transformer. One 180,000/202,000 kVA, FOA, forced oil/forced air-cooled, 55 °C/65 °C, 230 kV/14.3 kV generator step-up transformer with standard low voltage no-load taps 2-2.5% above and 2-2.5% below rated 14.3 kV, bushing CTS (6), 230 surge arrestors (180 kV rating) (3) bracket-mounted on tank, transformer low-voltage isolated phase bus duct flanges (14.3 kV wdg.), winding temperature equipment, and fault pressure relay.

6.7.3 Station Start-Up Transformer. One 12,000/16,000/20,000 OA/FA/FOA oil-air/forced air/forced oil-air-cooled, 55°°C, 230 kV/4.16 kV transformers which will have standard low voltage no-load taps 2-2.5% above and 2-2.5% below rated 4.16 kV, bushing CTS (6), bus duct flange for 4.16 kV connection on tank sidewall ANSI segment 1, winding temperature equipment, fault pressure relay, and equipped with 230 kV surge arrestors (rated 180 kV).

6.7.4 Isolated Phase Bus Ducting

Gas Turbine-Generator to GTG Step-Up Transformer

One isolated phase bus structure from generator to step-up transformer, including:

Three complete metal enclosures with provisions for taps to associated equipment and flexible connections to generator and step-up transformer

Three conductors--10,000-ampere, aluminum tubing

One set seal-off bushings

Three disconnect links

Three transformer flexible enclosures

Three transformer adaptor hoods

One isolated phase bus structure from main bus to stations auxiliary transformer, consisting of:

Three complete metal enclosures with flexible connections to transformer

Three conductors--1000 ampere, aluminum tubing

Two sets seal-off bushings

Three bushing current transformers (relaying)

Six bushing current transformers (metering and relaying)

One disconnect switch, TPST

Three transformer flexible enclosures

Three transformer adaptor hoods

Three transformer terminals

One isolated phase bus structure from main bus to gas turbine auxiliary transformer consisting of:

Three complete metal enclosures with flexible connections to transformer

Three conductors--100-ampere, aluminum tubing

Two sets seal-off bushings

Three bushing current transformers (relaying)

Six bushing current transformers (metering and relaying)

Three transformer flexible enclosures

Three adaptor hoods

Three transformer terminals

One isolated phase potential transformer and surge protective equipment consisting of:

Six potential transformers

Six current limiting fuses

Six drawout devices

Three surge arresters

Three capacitors

Three complete steel enclosures

Three connections to main bus tap

One generator neutral tie, consisting of:

One bus tie with flexible connections

One metal enclosure

Three generator terminals

One terminal for neutral cable

One generator neutral grounding equipment, consisting of:

One steel enclosure with provision for neutral connections

One isolation disconnecting switch

One grounding transformer

One secondary resistor

One set of interconnections

One supporting structure, consisting of: Complete supporting steel structure for bus structure and associated equipment including cross, longitudinal and vertical columns with hardware

Gas Turbine Generator to GTG Step-Up Transformer

One isolated phase bus structure from generator to step-up transformer, including:

Three complete metal enclosures with provisions for taps to associated equipment and flexible connections to generator and step-up transformer

Three conductors--10,000-ampere, aluminum tubing

One set seal-off bushings

Three disconnect links

Three transformer flexible enclosures

Three transformer adaptor hoods

One isolated phase bus structure from main bus to stations auxiliary transformer, consisting of:

Three complete metal enclosures with flexible connections to transformer

Three conductors: 1000-ampere, aluminum tubing

Two sets seal-off bushings

Three bushing current transformers (relaying)

Six bushing current transformers (metering and relaying)

One disconnect switch, TPST

Three transformer flexible enclosures

Three transformer adaptor hoods

Three transformer terminals

One isolated phase bus structure from main bus to gas turbine auxiliary transformer, consisting of:

Three complete metal enclosures with flexible connections to transformer

Three conductors: 100-ampere, aluminum tubing

Two sets seal-off bushings

Three bushing current transformers (relaying)

Six bushing current transformers (metering and relaying)

One disconnect switch, TPST

Three transformer flexible enclosures

Three transformer adaptor hoods

Three transformer terminals

One isolated phase potential transformer and surge protective equipment consisting of:

Six potential transformers

Six current limiting fuses

Six drawout devices

Three surge arresters

Three capacitors

Three complete steel enclosures

Three connections to main bus tap

One generator neutral tie, consisting of:

One bus tie with flexible connections

One metal enclosure

Three generator terminals

One terminal for neutral cable

One generator neutral grounding equipment, consisting of:

One steel enclosure with provision for neutral connections

One isolation disconnecting switch

One grounding transformer

One secondary resistor

One set of interconnections

One supporting structure, consisting of:

Complete supporting steel structure for bus structure and associated equipment including cross, longitudinal and vertical columns with hardware

<u>Steam Turbine Generator to ST/G Step-Up Transformer</u>

One isolated phase bus structure from generator to step-up transformer including:

Three complete metal enclosures with provisions for taps to associated equipment and flexible connections to generator and step-up transformer, wall bushings and at generator foundation

Three conductors: 9000-ampere, aluminum tubing

Two sets seal off bushings

One wall frame and support plate

Three disconnect links

Three transformer flexible enclosures

Three transformer adaptor hoods

One isolated phase potential transformer and surge protective equipment consisting of:

Six potential transformers

Six current limiting fuses

Six draw-out devices

Three surge arresters

Three capacitors

Three complete steel enclosures

Three connections to main bus tap

One generator neutral tie, consisting of:

One bus tie with flexible connections

One metal enclosure

Three generator terminals

One terminal for neutral cable

One generator neutral grounding equipment, consisting of:

One steel enclosure with provision for neutral connections

One isolation disconnecting switch

One grounding transformer

One secondary resistor

One set of interconnections

One supporting structure, consisting of:

Complete supporting steel structure for bus structure and associated equipment including cross, longitudinal, and vertical columns with hardware.

Nonsegregated Phase Bus Duct. (Connection from Station Start-Up Transformer to 4.16 kV Metal Clad Switchgear) One lot--metal-enclosed, nonsegregated, phase bus, 3-phase, 3-wire, 4.16 kV rated at 400 amperes consisting of standard lengths of straight sections, elbows, flanges, flexible connections, gasketing, bus and internal supports to a switchgear termination, transformer termination cable tap box. One lot--bus duct support columns.

6.7.5 Ground System

6.7.6 Battery Systems. Station battery systems, consisting of 60 lead acid cells, static rectifier-type charger, racks, stands, interconnections, and accessories. Nominal 130 V DC system is designed for 1500 amp-hours at eight hour rate; 480 V, 3-phase, 60 Hz charger is rated at 150 A.

Section 7

OVERALL PLANT OPERATING MODES

7.1 INTRODUCTION

A major design objective with respect to the CGS-CC system is that it retains the basic operating modes that are characteristic of General Electric Company's combined cycle STAG system (Steam and Gas), which are commercially available with gas turbines operating in the 1900 °F to 2000 °F range. The data on Figure 7-1 shows the basic operating mode over the load range, wherein, in order to optimize overall plant performance, only one of the two gas turbines operates below about 50% of plant output. Another outstanding characteristic of the combined cycle (STAG) portion of the plant, when operating on No. 2 distillate, is its ability to start, synchronize, and load to a condition permitting transfer to low-Btu gas in about one hour, from a hot standby condition. Both of these operating modes, at-load and startup, are executed with the following design features:

1. Centralized Control--Operating decisions and actions are made in one control room.
2. Automatic One-Line Controls--One operator at the control panels for normal operation.
3. Automatic Plant Start-Stop--One operator at the control panel for a startup.
4. Independent Manual Control--A full complement of manual controls is provided so that the operators can take over functional control of the plant.
5. Flexibility--Automatic controls allow taking full advantage of the inherent flexibility of STAG system to achieve fast starts and operation over a wide load range at favorable heat rates. Manual controls allow separate portions of the plant to be operated independently.
6. Reliability--Only proven powerplant control equipment and techniques are used. High generation reliability is achieved by control equipment reliability, plus plant operating flexibility.

In achieving the objective of STAG plant flexibility, the operating characteristics and constraints of the gasification and cleanup systems must be considered. As a basis for discussing the overall plant operating modes, these fuel plant characteristics as well as those of the basic combined cycle portion of the plant will be discussed.

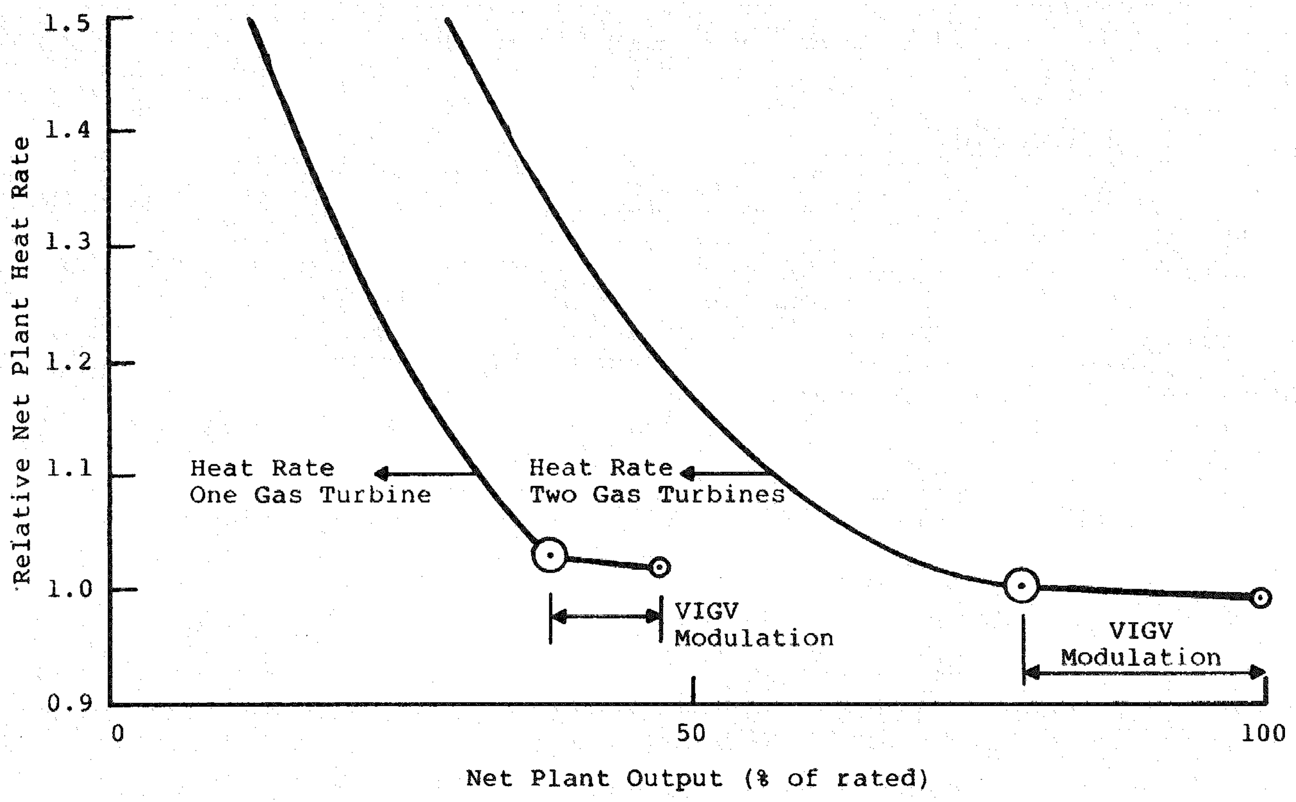


Figure 7-1. Plant Characteristics at Partial Load

7.2 CGS-CC PLANT SUBSYSTEM CHARACTERISTICS

7.2.1 Introduction

The integrated, fixed-bed CGS-CC plant may be considered to include five (5) major subsystems:

1. The fixed-bed gasification system
2. The low-temperature gas cleanup system
3. The water-cooled, 2600 °F gas turbine-generator
4. The unfired HRSG
5. The steam turbine-generator and its associated subsystems

7.2.2 The Fixed-Bed Gasification System

The advanced, fixed-bed gasification system is characterized by low-temperature operation in which there is no slagging. Consequently, following a shutdown, the total gasifier can be safely shut down by simply tripping the air and steam blast to the grate area and "bottling-up" the system. The system can then be kept in a hot standby condition near rated pressure by about 15 minutes of "pulse firing" every 2 hours. Or the system can be left overnight, with some decay in pressure and loss of temperature, and still be ready for a relatively fast startup.

The data on Figure 7-2 summarizes the operating characteristics of the fixed-bed gasifier during both a cold and a hot startup situation. The startup is initiated with a suitable

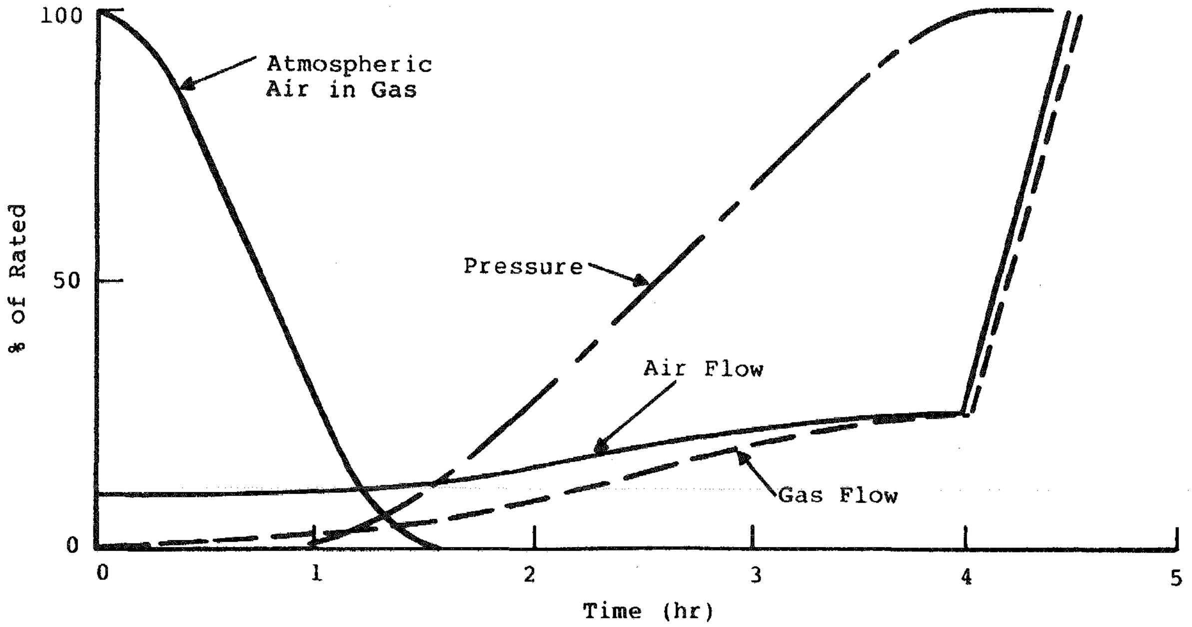


Figure 7-2. Typical Startup of A Cold Gasifier with Gas Cleanup System in Operation

material, such as wood, using about 10% air. Combustion products are vented until the oxygen content in the stack has dropped to a level suitable for flaring. Gas flow is transferred to the cleanup train and steam injection initiated as the system is gradually pressurized. As the gasifier is pressurized, the air flow is ramped from 10% to 25%. The gas flow increases, with air flow reaching about 25% by the time the gasifier is at normal operating pressure. From 4 to 8 hours will be required to reach this condition, which is equivalent to the hot standby state. Beyond this point, the response of the gasifier is the same as a hot restart with the capability of going to full output in about 30 minutes.

In the event of a plant trip which requires a fuels plant trip, the gasifiers are bottled with no external steam and air flow required for about two hours. This shutdown is accomplished without flaring gas or blowing relief valves. During this period the gasifiers are available for a hot restart. Beyond the 2 hours, pulse firing will be required to maintain the hot standby condition.

7.2.3 The Gas Cleanup System

The Benfield gas cleanup system, as well as other process equipment associated with the gas cleanup system, operates at constant steam temperatures, but with varying mass rates. In addition, consideration is being given to variable pressure operation.

Carryover of the potassium carbonate is a possible problem if the gas velocities become excessive. This condition can be encountered when the mass flow is too high or if there is too great a pressure change at a given mass flow.

Another problem is loss of effectiveness at partial loads in the Benfield system. These do not affect controllability per se, but can and do make it necessary to use multiple cleanup trains so that, by cutting out one train, efficient light load cleanup can be achieved. Such requirements introduce the problems of changeover valving and the related controls.

7.2.4 The Gas Turbine

One of the objectives in establishing the operating modes and the associated control system for the integrated CGS-CC plant is to retain as much of the current STAG philosophy of operating and controlling as possible, wherein the gas turbine is able to retain its very rapid startup without serious consequences with respect to the HRSG and steam turbine.

Figure 7-3 indicates the three major input loops for the standard one-shaft control system: startup, speed, and temperature. The output of these is fed into a minimum value gate,

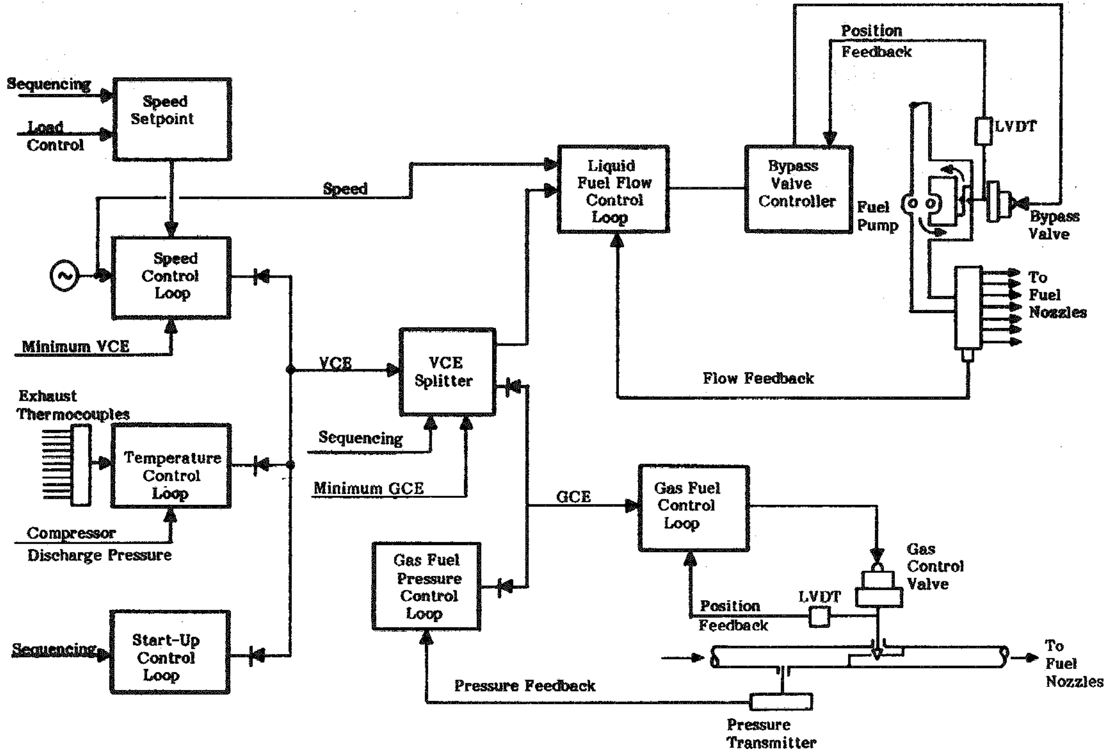


Figure 7-3. Simplified Control Schematic Gas Turbine Follow Mode

where the parameter requiring the least fuel will take control. The output of this minimum value gate is the one basic output: VCE (electronic control voltage), which, in turn, determines fuel flow.

Into these three input loops may be fed a number of derived parameters, such as acceleration, as well as separate inputs, such as load. The output may, in turn, be split into separate values, such as LCE (liquid fuel control) and GCE (gas fuel control).

STARTUP LOOP

The VCE is determined by a number of preset values to obtain the proper fuel flow for cranking, warmup, acceleration, and a maximum ceiling. During startup the gas turbine is initially cranked to about 20% speed where, after purging, combustion is initiated. During the first several minutes, combustion will be controlled to warm up the machine and limit the rate of temperature increase. When critical temperatures permit, the fuel rate is modified to permit the machine to accelerate to 100% speed at a constant rate, where, after synchronization, the unit will automatically load to the required power level.

SPEED LOOP

The most important operating loop is the speed loop. It consists of the speed sensor, amplifiers, set point, and feedback, as well as appropriate pulse rate to analog converters, scaling resistors, etc. Normally the loading rate is set at about 8% per minute. The system will be operated with about 4% droop in order to share load proportionally.

TEMPERATURE LOOP

The temperature loop is the other main gas turbine control loop. Its main purpose is to limit the startup and operating temperature of the gas turbine to safe values. Exhaust temperature is used as the prime parameter, rather than turbine inlet temperature; this is dictated by the requirements for long sensor life, good sampling, serviceability, etc.

7.2.5 The Gas Turbine/HRSG/Steam Turbine System

During normal on-line operation of the plant, the steam system (HRSG and steam turbine) is slaved to the thermal input of the gas turbine. Design steam turbine throttle conditions are attained at only one operating point with respect to both ambient temperature and gas turbine load condition. Both steam generation and steam temperature decline as the load on the gas turbine is reduced, reflecting the lower exhaust temperature.

At reduced ambient temperatures, the gas turbine's mass flow increases and the exhaust temperature decreases, resulting in somewhat higher steam flow but lower superheat temperature. At higher ambient temperatures, the somewhat lower steam flow is accompanied by higher temperatures. Some degree of temperature control can be attained by using an oversized superheater and reheater with attemperation.

In contrast to a conventional fossile-fired power boiler, which uses firing to control pressure, the unfired HRSG has no direct method for pressure control. Consequently, with the control valves in the wide-open position, the steam turbine's throttle pressure will be proportional to the lower steam flows associated with reduced gas turbine, and system, power. The reduced temperatures associated with this type of reduced pressure, partial-load operation have the unique effect of maintaining about the same expansion line and, hence, about the same percent moisture in the last stage. Consequently, water erosion, which is a function of this percent moisture, is not a problem in unfired HRSG systems when variable pressure operation is used.

In actual practice, a degree of constant throttle pressure operation can be used without erosion problems, and is achieved by using the steam turbine's control valves as pressure-regulating valves, as shown on Figure 7-4. Operating on the three pressure plateaus, as shown, gives additional stability to the overall steam system. Note that there is a minimum pressure plateau, which is required before the steam turbine is put into operation. As steam flow increases, the control valves open to maintain pressure until they are at the 95% open position, when the set point is ramped up to the intermediate pressure plateau, Pm. Similarly, the pressure is maintained until the 95% valve position is reached, and the set point is increased to the full design pressure p_H. When steam flow decreases, the pressure is not reset to a lower pressure until the 60% valve position is reached.

The normal gas turbine startup as described in Section 7.2.4 imposes a very high and rapidly increasing heat flux on the HRSG. The resulting operating characteristics of the HRSG are indicated on Figure 7-5. Note that in about 5 minutes the gas turbine has been cranked, purged, fired, brought to speed, and synchronized. As load is subsequently increased, with a corresponding increase in exhaust temperature, the steam temperature follows closely. With only the relatively small steam flow for line heating, etc, the pressure also ramps up rapidly, until a minimum is reached in about 15 minutes. As steam generation increases, a steam bypass valve acts to maintain the header pressure, thereby permitting the steam turbine to utilize whatever is required for its startup, at a rate compatible with temperature levels in critical areas.

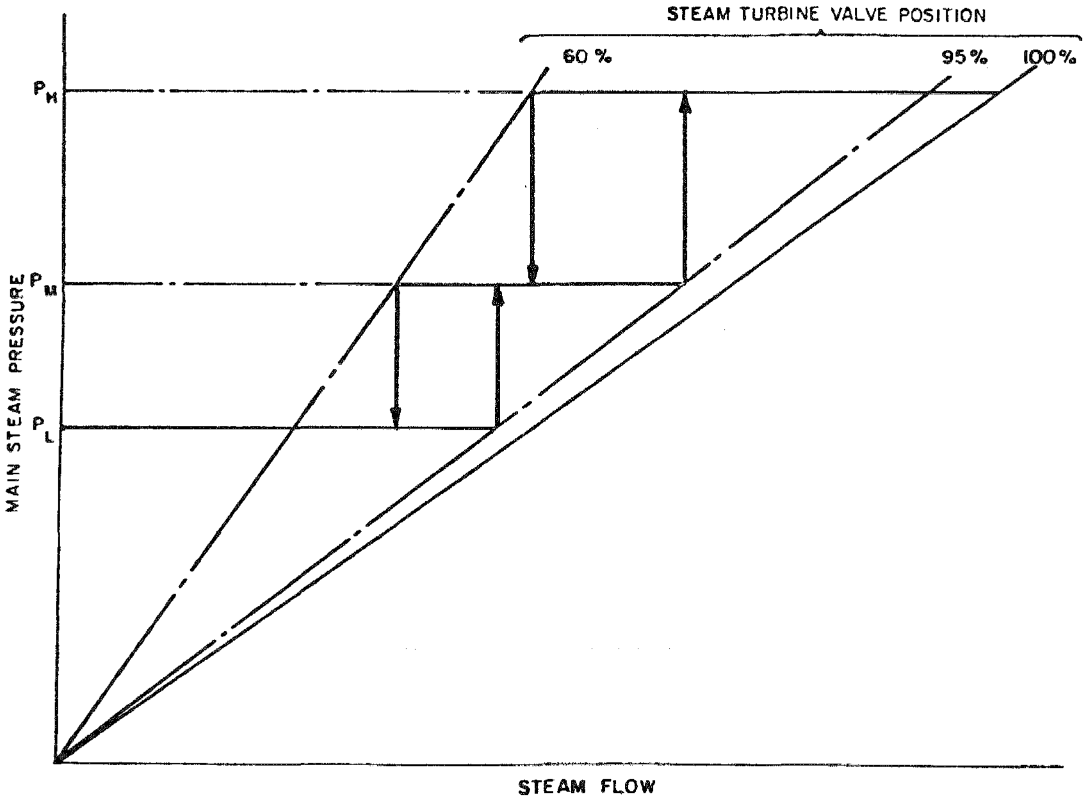


Figure 7-4. Typical Steam Turbine Initial Pressure Schedule

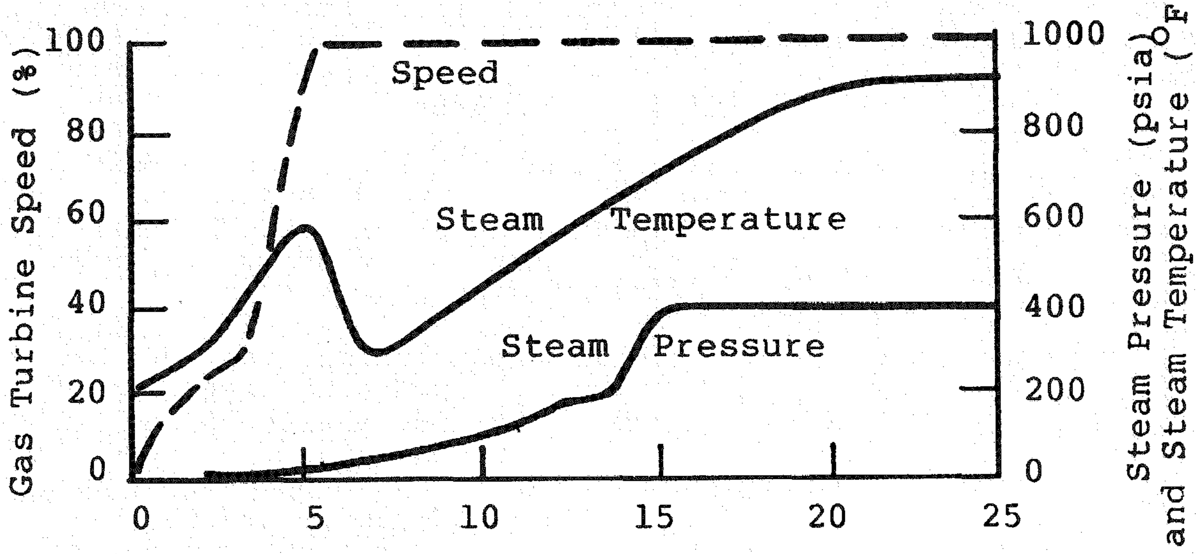


Figure 7-5. Hot Startup Characteristics

7.2.6 Main Final Control Elements of the CGS-CC System

7.2.6.1 Gasifier - Gas Turbine Interface. During normal integrated operation of the CGS-CC plant, process air from the gas turbine and low-Btu gas from the gasifier are controlled with the elements indicated on Figure 7-6. As indicated, load control is to the gasifiers, wherein, in response to a change in load demand, the rate of gasification is modified first, with a subsequent effect on load as the gas turbine control valves, acting to maintain upstream gas pressure, adjust the gas flow to the gas turbine. The incorporation of the required gas fuel pressure control loop into the gas turbine's control system is shown on Figure 7-3.

It should be emphasized that there are attractive variations on the basic "gas turbine follow" mode, which will permit quicker load response. For example, it is quite likely that the inherent accumulator capability of the fuels plant can be utilized to some extent, in order to permit the gas turbines, as well as the fuel plant, to immediately respond to changes in load demand.

An alternative to the simple gasifier follow and turbine follow control modes is a form of coordinated control, wherein both the gasifier and gas turbine respond to load demand changes. The fundamental control functions for this coordinated control scheme are shown on Figure 7-7. In response to a change in load demand, the gasifier blast air system reacts directly, while the

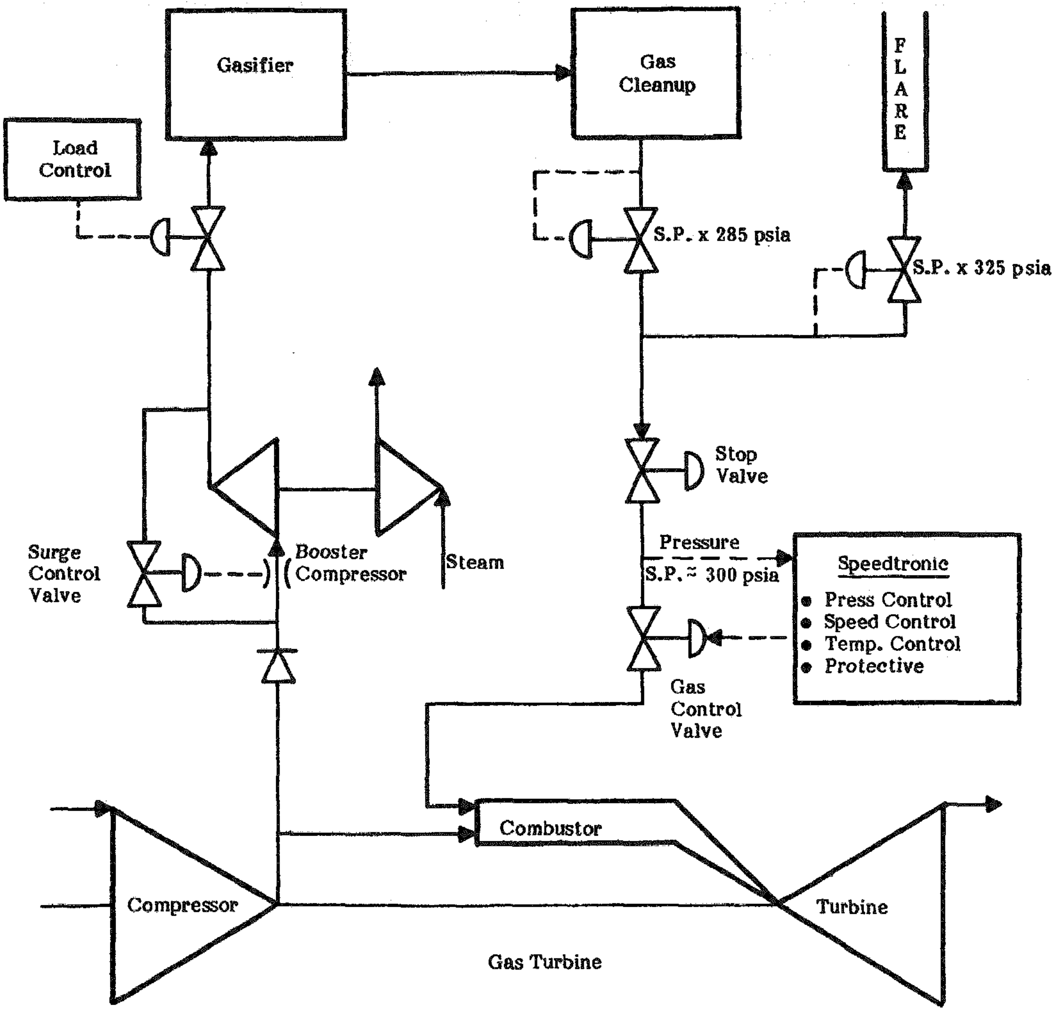


Figure 7-6. Gas Turbine Follow Control Mode

reaction of the gas turbine control valve is modified by a gasifier pressure error signal, so that pressure control is by the gas turbine control valve.

A form of the coordinated control method combines the virtues of the simpler gasifier and turbine follow modes but avoids their individual pitfalls of wide pressure swings or sluggish load control. The scope of the Phase I effort did not permit a study of these trade-offs, but it is hoped that subsequent phases of this program will permit determination of a specific preferred system.

Note that the basic requirements of the gas turbine control system with respect to speed, temperature, and contingencies, overrides the pressure-regulating function.

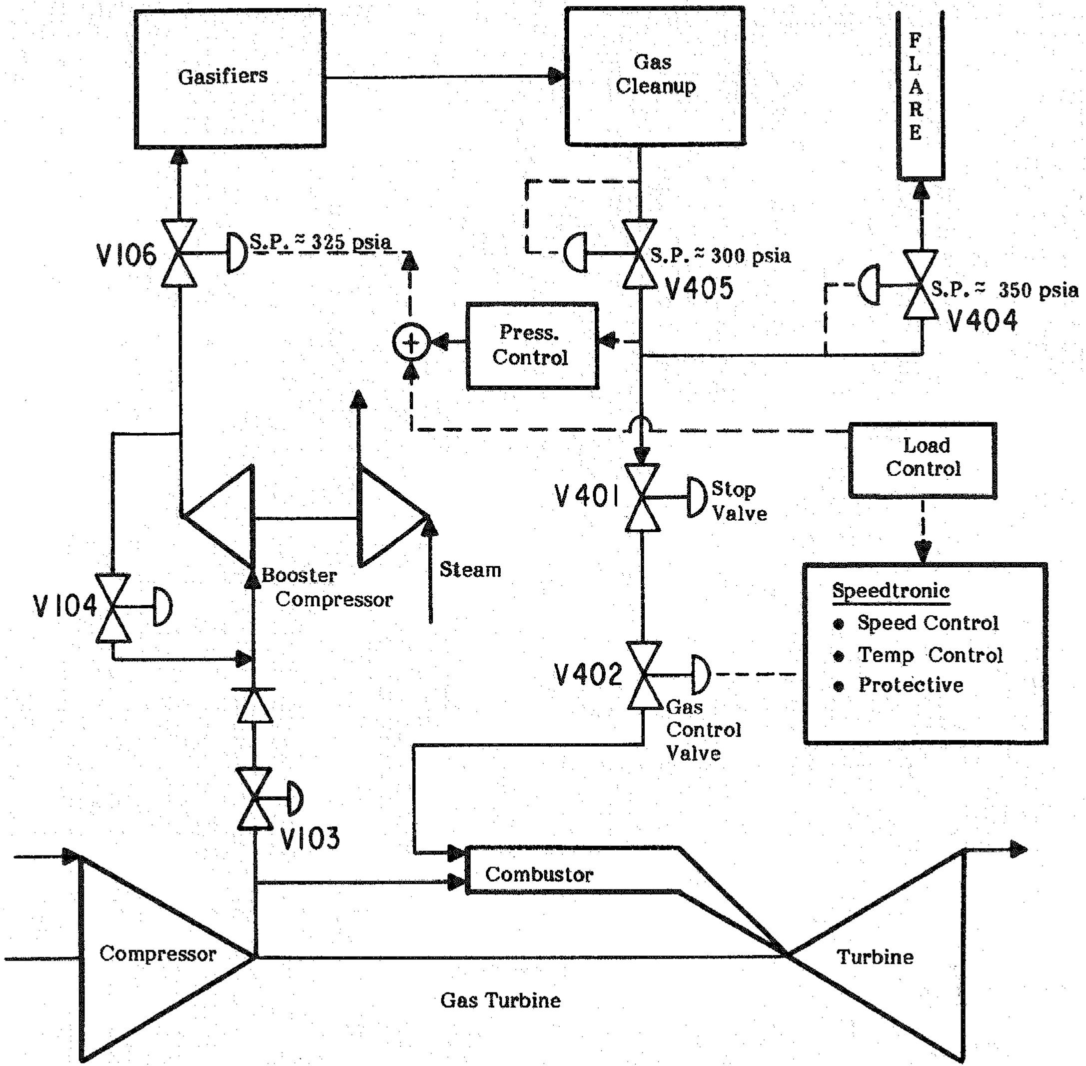


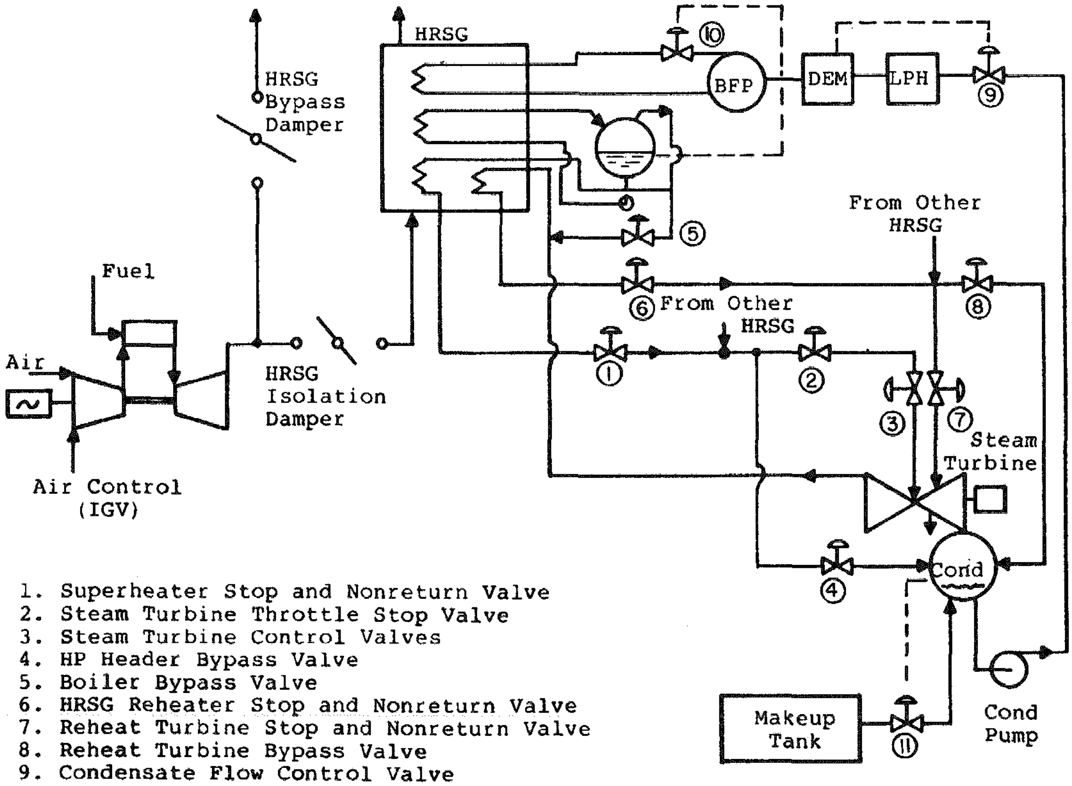
Figure 7-7. Coordinated Gasifier Follow Mode-Simplified Diagram

The fuel plant also has controls that safeguard the system in the event pressure regulation by the gas turbine fuel valve is inadequate. A flow will act to prevent overpressurization and a throttling valve will prevent underpressurization.

7.2.6.2 Gas Turbine - Steam System Interface. The main control elements necessary to interface the gas turbine, HRSG, and reheat steam turbine are shown on Figure 7-8. In addition to fuel control, as previously discussed, gas turbine power can also be controlled by modulating the compressor's air flow by means of inlet guide vanes. By operating with reduced air flow and constant exhaust temperature at part load, the gas turbine operates at higher temperatures than it would if full flow were maintained, with an associated improvement in gas turbine and overall plant performance. A relatively flat plant heat rate is achieved in the 80% to 100% load range where the air is being modulated, as indicated on Figure 7-1; below about 80% load, load reduction is accomplished at constant air flow and with a reduction in firing temperature, thereby resulting in a relatively sharp deterioration in plant performance. To optimize plant performance below approximately 47% load, the plant can be operated on only one gas turbine.

An HRSG isolation damper and an exhaust gas bypass damper are used to permit simple-cycle gas turbine operation during startup, as well as normal heat recovery operation. At the HRSG superheater and reheater outlets, stop and nonreturn valves (1) and (8), respectively, are utilized to seal the HRSG until steam flow and permissive conditions are suitable. These valves are used during the startup and shutdown sequences, and also to prevent reverse steam flow from the headers.

Conventional steam turbine stop valves (2) and control valves (3) and reheat stop and nonreturn valves (7) are included. Valves (4) and (8) bypass main throttle steam and reheat steam around the steam turbine during startup until the flows and steam turbine conditions are suitable. Water level controls for the condenser Hotwell, deaerating heater, and the HRSG drum are controlled by valves (11), (9), and (10), respectively.



1. Superheater Stop and Nonreturn Valve
2. Steam Turbine Throttle Stop Valve
3. Steam Turbine Control Valves
4. HP Header Bypass Valve
5. Boiler Bypass Valve
6. HRSG Reheater Stop and Nonreturn Valve
7. Reheat Turbine Stop and Nonreturn Valve
8. Reheat Turbine Bypass Valve
9. Condensate Flow Control Valve
10. HRSG FW Control Valve
11. Condensate Makeup Control Valve

Figure 7-8. Main Control Elements

7.2.6.3 Headering and Component Arrangements. The two gas turbines, two HRSG's, two gas cleanup systems, one Claus tail gas plant, two steam-turbine-driven booster compressors, single reheat steam turbine, and two banks of seven gasifiers are functionally arranged and headered as shown in Figure 7-9. This installation will permit two parallel, independent gas turbine/fuels plant trains to be combined with a single steam turbine system. In normal operation, the two trains would be isolated. The arrangement here permits flexibility of operation and eliminates the possibility of interaction between the pressure control loops on the two trains. For startup and other conditions, it is possible to interconnect the two gas systems, the two air blast headers, and the two steam blast headers.

Not shown on the diagram are the auxiliary air and steam supplies necessary to effect a cold start and also to maintain the hot standby condition. In a cold start, the gasifiers can be partially pressurized directly by gas turbine compressor discharge air, if desired, but the more likely source will be an auxiliary air compressor feeding the process air header. The auxiliary steam supply will furnish steam to the cold reheat steam header during startups in order to supply both the gasifiers and the boost compressor drivers. As the power plant warms up, the HRSG steam output will reach a level high enough to take over this function. Finally, as the reheat steam turbine comes on line, the steam header for the gasifiers and boost compressors will be supplied by steam from the cold reheat point of the steam turbine generator.

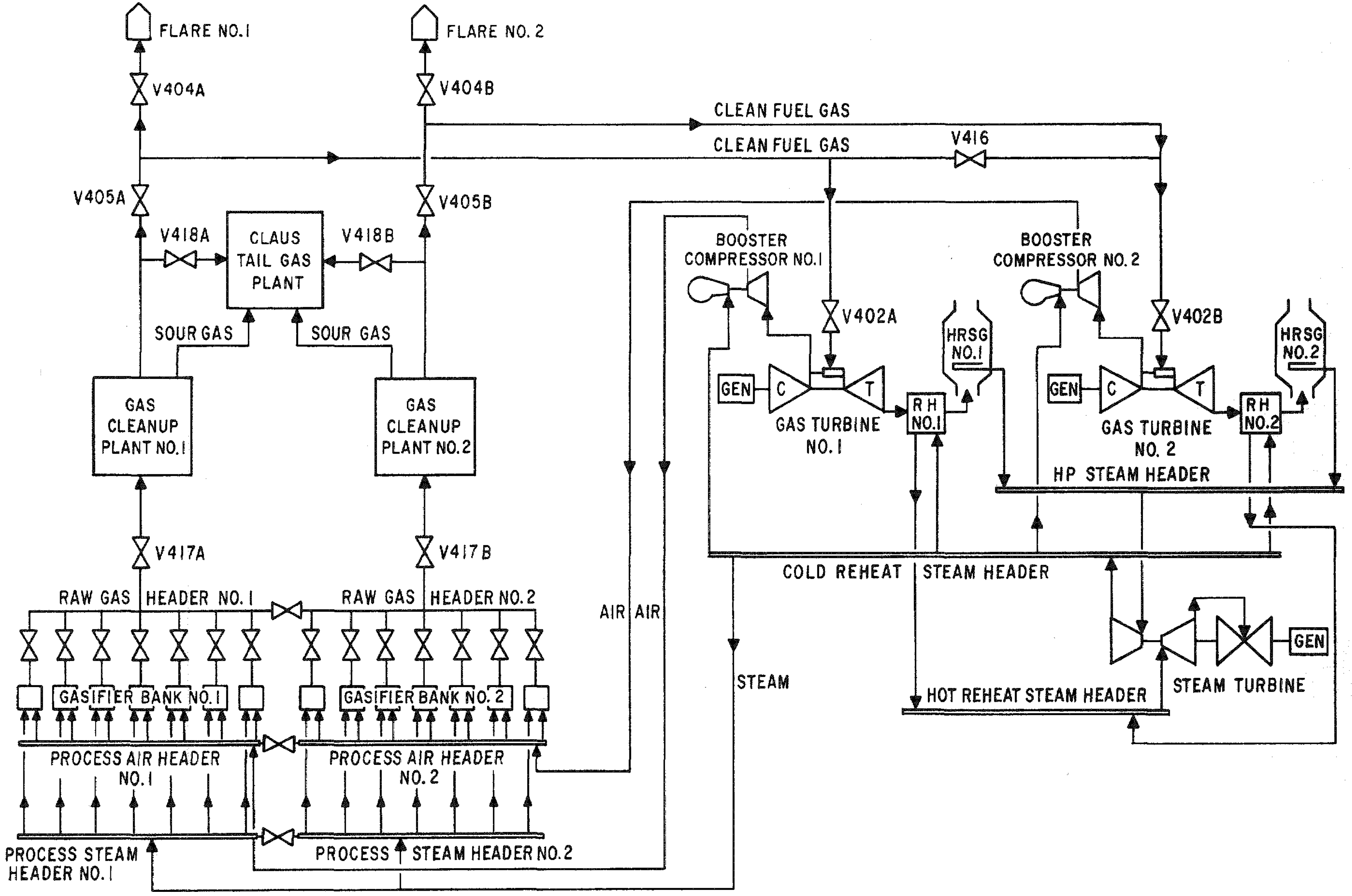


Figure 7-9. Major Components and Headers--Case A

7.3 PLANT OPERATING MODES

7.3.1 Plant Load Control

The overall plant control is provided by the master load controller. The gas turbine and steam turbines operate in a modified turbine-follow mode, wherein the master load demand signal is a master gas flow demand to the coal gasification system, but derivative feed forward signals to the gas turbine will be used to prevent unnecessary load variations by transiently adjusting the fuel header pressure control set point.

The load demand will be automatically divided between the operating gas turbines, selecting the variable inlet guide vane (VIGV) position for optimum overall plant efficiency at partial loads; the latter is automatically accomplished by maintaining a constant gas turbine exhaust temperature at partial loads.

7.3.2 Start Sequences

Depending on the period of shutdown and conditions maintained during shutdown, a plant may require a "cold," "warm," or "hot" start. The pacing items in such starts are the steam turbine temperature and the gasifier conditions. If the steam turbine has been shut down only overnight (12 hours or less), it can be considered in the hot condition. Similarly, if the gasifiers have been kept on a pulse firing cycle, the gas cleanup system maintained at temperature, the Claus plant held at temperature by auxiliary fuel firing, and the booster drive turbines maintained at temperature, a hot start can be considered. If these conditions do not exist, the operator will have to bring the individual systems up to the required standby conditions. As shown before, it can take approximately four hours to bring the gasifier up to "hot standby." In addition, prior to start, the operator must bring one booster compressor driver up to minimum compressor speed and must have the steam, air, gas turbine, and booster air compressor systems in the state of readinesss briefly described by Table 7-1.

In executing a hot start the major constraints and assumptions that govern are delineated in Table 7-2. It is envisioned that the hot start will be automatically controlled in a manner analogous to the current STAG systems.

On initiation of a hot start, the start sequence for one gas turbine is started immediately, as is the blast on the first gasifier from the auxiliary air supply system. The boost compressor bypass valve will start to ramp closed, and pressure will start to build up in the air header. Approximately six minutes after start, the first gas turbine is synchronized while still on distillate fuel, and its load ramp started. At about the eight-minute point, the maximum gas turbine load on distillate (15 to 20% load) is reached, and load is held at that level while the HRSG warms up.

Table 7-1

HOT START READINESS STATE

FUELS PLANT

- Gasifiers on Hot Standby
    - Air and Steam Headers and Gasifier at Pressure (Aux. Air & Steam Systems On)
    - Drum Levels OK
    - Quench Water Flow On
- Gas Cleanup Plants On Hot Standby
    - Benfield Regenerator Reboiler Steam Heater On
    - All Pumps On, Make-Up Available
    - All Elements Exposed to Fuel Gas Are at Temperature
- Claus Tail Gas Plant and Temperature On Standby Fuel

GAS TURBINE

- On Turning Gear, Isolation Damper Closed, Bypass Damper Open
- Liquid Fuel System in Standby Mode
- Cooling Water Pressure and Temperature OK (all pumps on)
- Lube System On

BOOSTER COMPRESSOR

- Booster at Min. Compressor rpm: Drive Turbine On Aux. Steam Supply
- Air Bypass Valve Full Open
- Precooler Water Flow On

STEAM SYSTEM

- HRSG Circ. Pumps On and Drum Levels OK
- DA Temperatures and Pressures OK: Level @ Max. Normal
- All Steam Drain Valves Open
- Aux. Steam Supply Running and Supplying Process Steam Header
- Condenser Vacuum in Range
- Steam Turbine On Turning Gear (lube system on)
- Steam Turbine Eccentricity and Diff. Expansion OK
- Auxiliary Cooling Water Pump On "Steam Turbine Restart"

Table 7-2

MAJOR CONSTRAINTS AND ASSUMPTIONS GOVERNING HOT START SEQUENCE

FUELS PLANT

- Fuel Gas Reaches Combustible Value 10 Minutes After Warm Restart of Gasifier
- Gasifier Reaches Full Output 30 Minutes After Warm Restart
- Maximum Turndown Capability of Each Cleanup Plant is 50%
- Auxiliary Air Supply Can Support One Gasifier at Full Output
- Auxiliary Steam Supply is Not A Limitation
- Gasifiers Are Re-started At One Minute Intervals

GAS TURBINE

- Nozzle Cooling Water On Before Roll
- Turbine Cooling Water On At 20% Speed Prior To Firing
- Start On Distillate
- Synchronism 6 Minutes From Roll
- Maximum Load On Distillate is 15 To 20%
- Maximum Loading Rate is 8% Per Minute
- Gas Turbine Transfers To Pressure Control (Turbine Follow) When Gas Turbine Flow Demand Equals Gasifier Output

STEAM PLANT

- Piping and Headers Sequentially Warmed Until Acceptable Steam Conditions Are Reached
- Turbine Rolls When Steam Chest Temperature And Bypass Flows Reach Acceptable Levels
- Synchronism 15 Minutes From Roll
- Maximum Loading Rate is 4% Per Minute
- Transfers To Pressure Control When Bypass Valves Close

Meanwhile, the first gasifier's blast is being ramped up, during which time its gas output is being flared. After ten minutes, the gas will be suitable for introduction to the cleanup system. Figure 7-10 shows the fuel plant output during the start sequence. Remembering that the output of the cleanup system may not be acceptable at levels below 50% turndown for each individual system, the clean gas output will be flared until that level is reached. (Since there are two cleanup systems, this percentage represents 25% of total fuels plant capacity.) By 15 minutes after the start, the first boost compressor will have come up to operating pressure. It will take over the supply to the first air header, and the start compressor will be transferred to the second header. Now that the first booster compressor is on line, it is possible to start the other gasifiers. In this example it is assumed that the gasifiers are started from this point on at one-minute intervals and ramped up individually. It is possible to ramp an entire bank-up as a single block of gasifiers, and such a mode should be considered in the future.

Referring now to Figure 7-10, the first bank of gasifiers and its cleanup system reaches its 50% capacity level (25% of total plant capacity) in 30 minutes. The gas is suitable at that point for burning in the gas turbine, and transition from distillate to fuel gas on the first gas turbine will occur at that time. Note from Figure 7-11 that the gas turbine will not accept the full output of gas plant No. 1 immediately, since it can only be loaded to 15 to 20% while on distillate. As soon as transition is complete, the gas turbine will be ramped up in load until its flow requirements match the output of gas plant No. 1, at which point the gas turbine goes into the pressure control (gasifier follow) mode of control. From this point on, the gas turbine output is paced by the fuel gas plant output and will reach baseload conditions at the 45-minute mark. Meanwhile, the second fuel gas plant, boost compressor, and gas turbine are being brought on line and reach base load at about the 55-minute mark. Figure 7-11 shows the loading of the gas turbines and the steam turbine. It can be seen that the second gas turbine will load up slightly faster than the first, since six gasifiers will be ramping simultaneously in gas plant No. 2, while only five were ramping in the first.

During the loading of the gas turbines, their HRSGs and the steam system have been going through their warmup cycles as generally described in Section 7.2.5, and, at about the 45-minute mark, the steam turbine will be synchronized, reaching 100% load at the 70-minute mark.

Note (Figure 7-11) that 100% gas turbine load is reached in about 55 minutes, and full plant output in approximately 70 minutes.

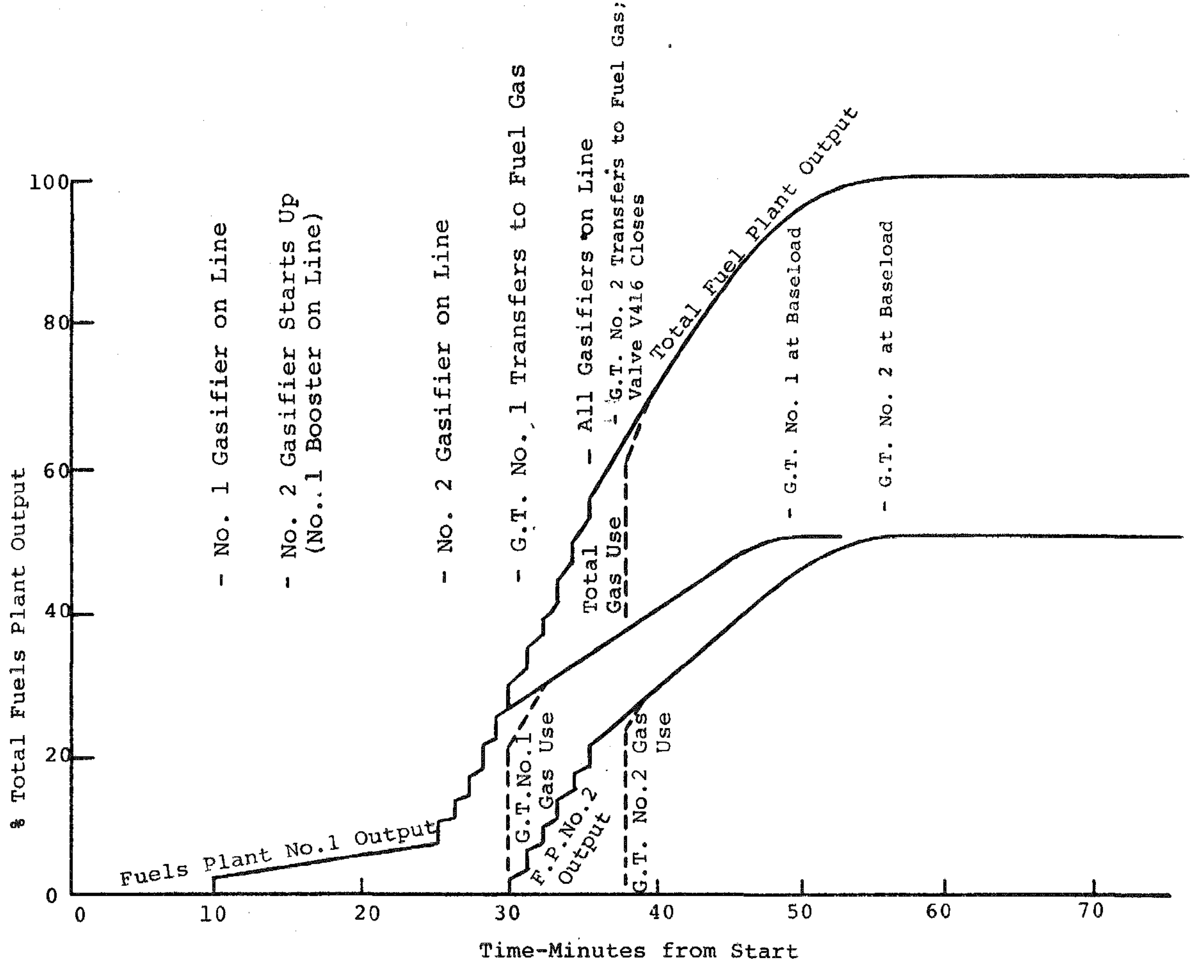


Figure 7-10 Hot Start Sequence - Fuels Plant Operation--Case A

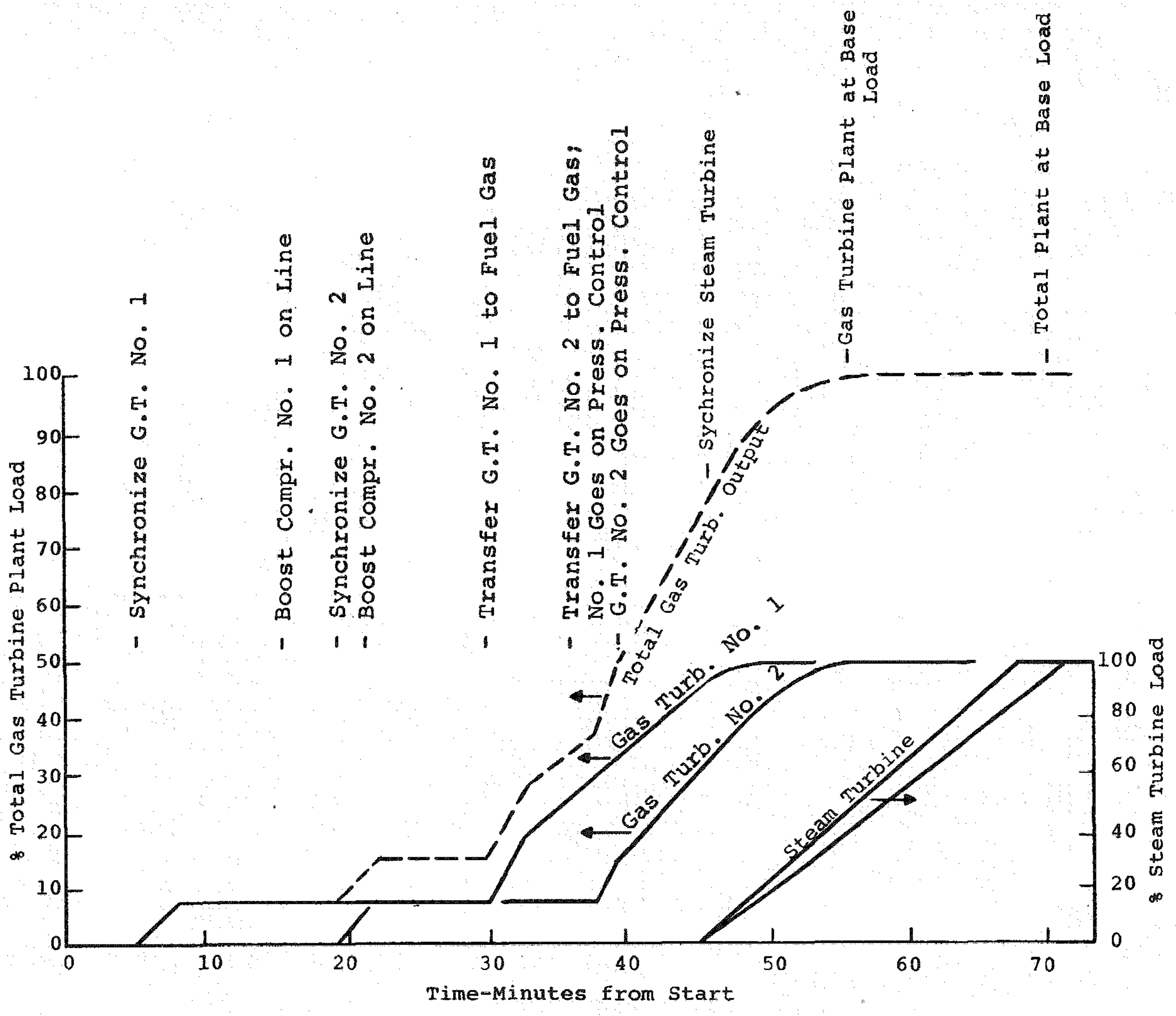


Figure 7-11. Hot Start Sequence - Plant Output--Case A

7.3.3 Shutdown Sequence

Two types of station shutdown, which should span the maximum and minimum times, excluding a plant emergency trip, have been considered. The first is a shutdown to the hot standby mode, where the shutdown condition is one permitting a plant startup in the minimum possible time. The principal requirement in such a shutdown is to maintain the highest possible temperature of the steam turbines. The second type of shutdown is for maintenance. In this case, maximum cooldown of the various systems is usually desired.

Prior to starting the shutdown to a hot restart condition, the auxiliary steam and air supplies must be in a state of readiness. Then, on the station operator's command, the shutdown sequence will begin. To maintain high turbine steam temperature, it is necessary to unload the steam turbine-generator without reducing the superheat of the steam to any significant degree. For this reason damper actions are used to unload the steam turbine, maintaining gas turbine exhaust temperature high. As each HRSG is shut down, the corresponding fuel gas plant is unloaded and its gas turbine follows it down. As the separate gas fuel plants reach their 50% turndown points, they will be held at that operating level as the gas turbines continue to unload. During this period, the fuel gas plants will be on flare. When the first gas turbine is down to a load level permitting transition to distillate, the transition will occur and the gas turbine will continue shutdown under automatic sequence control. The second HRSG will maintain enough steam flow to support the process while the second gas turbine is being unloaded, until steam conditions deteriorate to a point where the auxiliary steam supply takes over the supply of the process and booster. When transition to distillate is reached on the second gas turbine, it will transfer to the normal shutdown sequence on distillate, while the booster compressors and the fuels plant are brought down rapidly to the hot standby condition. Final action is to "bottle up" the HRSGs and pulse-fire the gasifiers to maintain the standby condition. The normal shutdown to hot standby will take 60 to 90 minutes.

In a shutdown for maintenance, the gasifier load set points would be ramped down, with the entire plant load following the reduction in fuel gas. Steam turbine cooling would occur as the gas turbines unloaded. Depending on the load conditions at the beginning of shutdown, considerable lengths of time could be required for gas turbine and steam turbine cooldown before they could be removed from turning gear in the case of required maintenance.

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