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# HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

## Phase I – Program and System Definition

### Topical Report – Overall Plant Design Description Liquid Fuel Combined Cycle Electric Power Plant



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# HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

## Overall Plant Design Description
## Liquid Fuel Combined Cycle Electric Power Plant

## ABSTRACT


The combined cycle plant described in this report utilizes an advanced 2600$^{\circ}$F inlet temperature combustion gas turbine engine and burns a coal-derived liquid fuel. The plant is intended to serve the base and intermediate loads of a utility system. This operation requires that the equipment be capable of cyclic duty and of starting and accelerating to a full load condition in approximately one (1) hour.

The plant is comprised of two (2) air-cooled dual liquid fuel combustion gas turbine engines, each rated at a gross output of 122,663 KW. The 1200$^{\circ}$F exhaust heat of each combustion turbine is recovered in an unfired Heat Recovery Steam Generator (HRSG) generating steam at 1800 psig/1000$^{\circ}$F/1000$^{\circ}$F. Intermediate pressure steam is also generated and is mixed with the cold reheat steam prior to the reheater.

The tandem compound, double-flow reheat steam turbine operates at throttle conditions of 1800/1000$^{\circ}$F/1000$^{\circ}$F TT and a condenser pressure of 2.5" HgA. Gross power generated is 72,515 KW per combustion gas turbine unit or 145,030 KW for the plant.

The combined heat balance of the plant after allowing 7150 KW for total plant auxiliary power, shows a HHV heat rate of 6,966 Btu/KwHr at a net plant output of 383,206 KW. This heat rate translates to an overall efficiency of 49 percent.

The alternate plan heat balance, which uses water, steam and air for combustion gas turbine cooling shows the net plant power to be 393,638 KW at a HHV heat rate of 7182.6 Btu/KwHr. The power output of this plant is 2.7 percent greater than the base plant, but at an efficiency 3 percent less.

The multi-generator plant design and redundancy of critical components and controls gives a capability to maintain 50 percent minimum plant capacity in the event of the worst single projected component failure. Further, a preliminary analysis of unit availability shows that where individual unit availability is 93 percent or more, the availability of the combined cycle plant can equal or exceed that of a conventional single unit fossil fired plant.

On review of the complete OPDD, the single area requiring technological development is that required to bring a 2600$^{\circ}$F combustion gas turbine engine burning a coal-derived liquid fuel into commercial use.

# HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

## Overall Plant Design Description
## Liquid Fuel Combined Cycle Electric Power Plant

# INTRODUCTION

This topical report is an overall design description of a combined cycle electric generating plant having as its primary energy input, a coal-derived liquid fuel. The economic benefits of a combined cycle plant with combustion gas turbine engines and steam steam turbines were identified by the ERDA-sponsored ECAS studies.

The operating parameters of each combustion gas turbine engine design are unique and require individual cycle optimization. The combined cycle for this plant is matched to a combustion gas turbine having a nominal turbine inlet temperature of 2600°F exhausting to an unfired heat recovery steam generator operating in conjunction with an 1800 psig/1000°F/1000°F TT reheat steam turbine.

Two (2) combustion gas turbine engine cycles and the resulting overall combined cycle are presented. The base cycle employs a combustion gas turbine having air as the cooling medium for the turbine. The alternate cycle which is limited to a heat balance and general description uses a combustion gas turbine having water as the cooling medium for the first two (2) stationary rows of turbine blading, and steam for the first two (2) rotating rows of turbine blading.

To translate heat balances into a power plant definition requires the design, selection and integration of the plant equipment. In addition, modern power plant design must address itself to the environmental impact it will have on its surroundings and keep this effect to a minimum. Further, the plant must satisfy a particular operational need and offer the utility owner operating reliability and availability commensurate or better than that which currently exists for the industry.

Each item of equipment in the plant is examined for proper application in meeting the plant objectives. Equipment directly associated with the power cycle and consisting of turbines, generators, condensers, heat exchangers and other related items are classified as part of the "power block".

The remainder of the plant equipment covering the service and support systems for the power block is designated as "balance of plant". The C.T. Main Company, an architect-engineer with considerable utility experience is employed in this area. In addition, the scope of responsibility of the C.T. Main Company extends to defining plant site development, electrical system design criteria and the suggested arrangement of all equipment in a final plant configuration.

The design requirements of the power plant are defined to include an integrated program on maintenance and reliability. This report describes techniques available with which to analyze power plant equipment and systems from a reliability and availability viewpoint.

Finally, the report describes the various operating modes of the plant and the operational condition of each major piece of equipment during each mode.

# HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

## Overall Plant Design Description
## Liquid Fuel Combined Cycle Electric Power Plant

# CONCLUSIONS AND RECOMMENDATIONS

The Reference Design on which this Overall Plant Design Description is based is a combined cycle power generating plant utilizing two combustion gas turbine boiler sets to achieve a total capability of approximately 400 MWs with a heat rate of 6,966 Btu/KwHr. The plant utilizes coal-derived liquid fuel with water washing and additive systems, as required. In preparing the total design definition of the plant, the major areas requiring technology that does not exist today are:

(1) The 2600$^{o}$F combustion gas turbine;

(2) Technology related to the use of coal-derived liquid fuels for acceptable turbine hot part life.

Other than the two areas cited above, all of the technology required to construct a power plant of the type described exists today. The principle risk would be in combining the various systems and subsystems without allowing sufficient time for proper integration and shakedown during the phases of design and initial operation. The system would be applied principally for intermediate power generation due to the plant capability of taking load swings, expected relatively low capital cost, and high cost of the coal-derived liquid fuel.

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

A cycle was investigated utilizing a combustion gas turbine with water-cooled stationary vanes and steam-cooled rotating blades in the front stages. This combustion turbine produces slightly more power but results in a cycle having an increased heat rate of 7,180 Btus/KwHr. The increased heat rate is principally caused by the additional energy removed from the hot-gas stream in the turbine element by the water-cooled stator vanes. The cycle is also more complex since the recovered energy is used to produce low-pressure steam which is superheated before induction into the steam turbine.

Areas where additional investigation would be appropriate include cost evaluation and controllability. The cycle optimization studies were all related to obtaining the best possible heat rate with little attention to the ultimate cost of electricity. Final cycle selection should be based on trade-off studies evaluating the contribution to heat rate improvement of each cycle modification versus the cost of the associated equipment and its effect on plant availability. The high efficiency combined cycle selected for use with coal-derived liquid fuels is somewhat more complex than combined cycles operating in the field today. Since this plant would be applied in intermediate generation where frequent starts, stops and load swings are required, a controllability study relating the characteristics of the plant to those of an electric utility system would be most appropriate.

During the initial cycle study phase, calculations were performed using a current combustion gas turbine engine. These calculations resulted in performance levels better than those of presently-installed combined cycle plants. It would therefore appear most beneficial if, in parallel with the development of the high temperature turbine, a demonstration plant utilizing current technology was undertaken to bring the total system to a state of utility acceptance concurrent with the commercial availability of the high temperature turbine.

The key factor in utility acceptance of this power plant would be assurance relative to the availability of coal-derived liquid fuels suitable for use as turbine fuels.

Specific recommendations are:

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

(2) Perform controllability studies to identify any problem areas relating to the application of a high efficiency liquid fuel fired combined cycle for intermediate duty in a utility system.

(3) Establish the cost and specifications for coal-derived liquid fuels which will be available as a result of the ERDA Development Programs.

(4) Communicate with the utilities at the earliest possible date relative to the forthcoming availability of coal-derived liquid fuels for use in power generation.

# SECTION 1
# DESIGN OBJECTIVES

This plant is intended for intermediate and base load service and utilizes an advanced technology high temperature combustion gas turbine engine.

Intermediate generation requires highly efficient plants capable of daily start/stop operation, as well as continuous operation. The design life and operating procedures characteristic of cyclic duty will receive special attention.

The overall plant design will also satisfy the design criteria necessary in today's environment. These criteria fall into the areas of environmental effects, operation, and availability.

## 1.1 ENVIRONMENTAL

### 1.1.1 Ambient Conditions

The plant design point shall be based on ambient conditions of $59^{o}F$ dry bulb, 60 percent relative humidity, 29.92" Hg barometer and a condenser pressure of 2.5" Hg absolute. Further, the plant shall be capable of operating or maintaining itself in a shutdown condition throughout an ambient temperature range of $-5^{o}F$ to $105^{o}F$.

### 1.1.2 Emissions

The plant design exhaust emissions utilizing coal-derived liquid fuel, shall be in accordance with the final EPA emission regulation for this type of plant. The latest recommended emission standard for combustion turbines is dated July 20, 1976 and was presented on August 10, 1976, by the EPA Emission Standards and Engineering Division.

The principal turbine emission limit contained in this proposed regulation is:

$NO_X$ - less than 75 ppm v when referred to 15 percent oxygen in the exhaust and referenced to the ISO Standard Atmospheric Conditions for humidity and pressure and adjusted for turbine efficiency.

### 1.1.3 Effluents

The plant design shall allow only uncontaminated aqueous drains that meet the standard (set forth in EPA 40 CFR Chapter I, Subchapter N, Part 423) to pass from the plant into surrounding waterways, runoffs or sewerage systems. All chemical and hydrocarbon contaminated drains of equipment and area drains of the plant itself, shall be segregated for collection and holding within the plant boundary. The holding areas will permit access for chemical sampling and treatment, such that the neutralized or treated effluent may be re-used or discharged from the plant. Provision will be made for storage and disposal of contaminated wastes. Attention will be focused on equipment and drains in the fuel oil storage, transfer and conditioning areas; chemical storage area; and water treatment areas.

### 1.1.4 Sound

Emphasis will be placed on the design, selection and location of plant equipment for near-field (3-5 feet) sound levels and duration of exposure to operating and maintenance personnel. Table G-16 of OSHA, Paragraph 1910.95, will be used for exposure time limits at different sound levels.

Where possible, operating equipment producing high noise emission levels will be located in low maintenance or unmanned areas. If it is not possible to so locate the the item, adequate sound attenuation shall be provided through installation of case-mounted sound deadening materials; installation of sound attenuating covers; or selection of quieter equipment performing the same function.

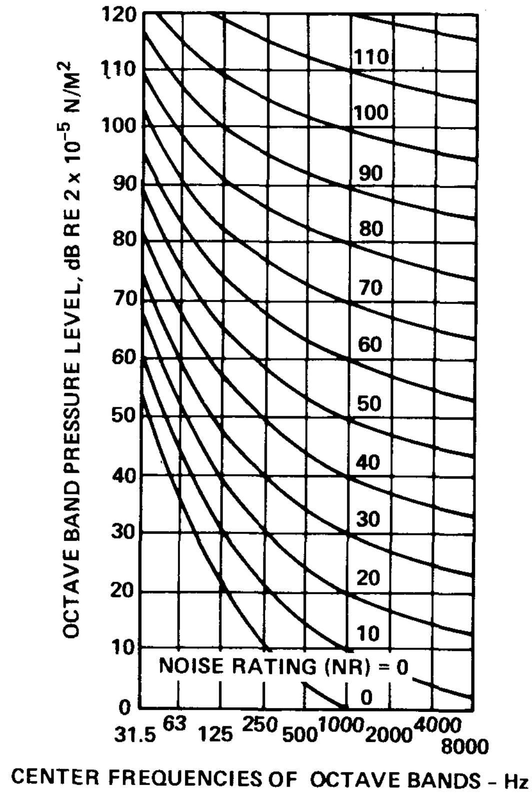
The overall plant is considered a point noise source when observed at a distance from the plant. The observed distance is known as the "far-field", and is defined as a distance of 4x plant length from the plant boundary. The plant boundary is further defined as an imaginary boundary at the extremity of the equipment supplied and is not to be taken as the site boundary.

The ISO Standard shall be the reference document in the design for "far-field" effects. This standard lists multi-sound level bands, each designated by a Noise Rating number (NR). Figure 1-1 displays the range of the Noise Ratings and the center frequency decibel level of each.

Sound attenuation of operating components integrated into the overall plant shall be designed to meet NR 50 in the far-field. This level is characteristic of central station design practice. The center frequency decibel levels of sound pressure levels (SPI) corresponding to NR 50 for the octave center frequencies are listed below:

| Octave Center Frequency - Hertz | | | | | | | |
|---|---|---|---|---|---|---|---|
| 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| 75 | 65.5 | 58.5 | 53.5 | 50 | 47.2 | 45.2 | 43.5 |
| Sound Pressure Levels - db | | | | | | | |

The assumption is made that the existing ambient sound levels at the site are 10 db or more below the levels of NR 50.




**NOISE RATING CURVES**
**Figure 1-1**

### 1.1.5 Aesthetics

The external appearance of the plant shall have a design commensurate with present day utility practice. In achieving an aesthetically pleasing plant, the turbine-generator units, along with their associated auxiliaries, shall be housed in a central enclosure. Overall plant height shall be held to as low a silhouette as practical. Roof lines and areas shall be kept clear and clean, wherever possible.

### 1.1.6 Seismic And Equipment Loads

The Middletown site described in WASH 1230 is classified as a Zone 1 site, as designated by the Uniform Building Code, for seismic design criteria. All plant equipment shall be designed accordingly. The Uniform Building Code shall be followed for designating live and dead loads on equipment and enclosures.

## 1.2 OPERATIONAL

The liquid fueled plant is designated for base and intermediate load service. Base service is defined as operation in excess of 6000 hours/year with minimum starts and stops.

Intermediate service is defined as 3000-5000 hours, year with up to 260 starts/year. Equipment design life shall be commensurate with central station practice, with attention given to intermediate service, since cyclic operation presents the most severe conditions. The plant shall further be capable of operating or maintaining itself in several different steady-state modes.

Cold Standby — Plant is in a shut down condition with environmental conditioning devices such as, heaters for freeze protection, activated as necessary and in an available operating condition.

Cold, Ready-To-Start — Plant is shut down, but certain auxiliary equipment of subsystems remain in operation, keeping fluid systems charged.

Hot, Ready-To-Start — Plant is in a warm standby status that will permit startup to a full load condition without incurring delays for such things as establishing condenser vacuum and steam turbine rotor warmup.

Power Generation — The plant is synchronized to the system and is producing electrical energy. The startup time to full base rating will vary, depending upon plant status, and is further defined as follows:

From cold, ready-to-start

$$T = t_1 + t_2 + t_3$$

where

$T$ = total time to plant base rating.

$t_1$ = time for combustion turbine to reach minimum load.

$t_2$ = steam turbine rotor warming soak period.

$t_3$ = loading time for steam turbine.

From hot, ready-to-start

$$T = t_1 + t_3.$$

The startup time (T) for a plant in the hot standby mode will be approximately one (1) hour.

Each combustion turbine shall have its own independent heat recovery steam generator (HRSG). In the multi-unit plant, the steam outlets of the heat recovery steam generators are manifolded into a common steam header. Steam header bypass to the condenser and associated control will allow combustion turbine-HRSG operation without the steam turbine generator, as long as the condenser is available.

Plant start-up shall be performed sequentially by first starting a combustion turbine-HRSG unit, commencement of steam turbine rotor warmup (if starting from the Cold, Ready-To-Start condition), and starting the remaining combustion turbine-HRSG units. Normal design plant turndown shall allow complete combustion turbine-HRSG units to be removed from operation, with the remainder of the plant operating at a reduced output.

While in the Power Generation mode with the steam turbine out of service, the plant will be capable of operating under HRSG wet or dry conditions. In the wet condition, the combustion turbine(s) is operating and steam is generated by the heat recovery boiler(s). The steam bypasses the steam turbine and is dumped directly into the condenser.

In the dry condition, the exhaust heat recovery boiler is dry with no steam generation and the combustion turbine at reduced load passes exhaust gas directly through the boiler. In this dry HRSG mode, it is necessary to limit the turbine exhaust temperature passing into the boiler to prevent a reduction in HRSG life. In this case, reduced turbine output will occur and would be considered an abnormal operating condition.

Steam turbine operation is possible with a minimum of one combustion turbine-heat recovery system operating in the wet condition.

The overall plant control system allows complete plant operation in all modes between the Cold, Ready-To-Start condition and Power Generation, from the control room, with assistance of roving operators. Water analysis will be performed by a chemist on a single shift per day basis.

## 1.3 AVAILABILITY

The term "Availability" is a statistical number that is influenced by many factors. As used herein, these factors will be classed as physical, those relating directly to equipment selection, and human-related, those indirectly associated with the plant operation.

Before actual availability values and the factors affecting the values are discussed, it is first necessary to define the term.

$$\text{Availability} = \frac{\text{Available Hours} \times 100 \text{ percent}}{\text{Period Hours}}$$

This definition used by EEI is a general definition applicable to components, individual generating units, or the plant as a whole, and considers the plant availability for service, whether or not it is actually in service. Further, plant capacity is not used in statistically determining plant availability. It is considered separately in determining the Plant Capacity Factor defined as:

$$\frac{\text{Net Generation, KW}}{\text{Period Hours x Max. Dependable Capacity, KW}} \times 100 \text{ percent.}$$

The ideal goal is to have a plant with 100 percent Availability at 100 percent Capacity Factor. Historical data (EEI Reports on fossil-fired power plants) shows that in practice, the average availability is 86 percent at a capacity factor of 66 percent. Physical factors affecting overall plant availability include cycle configuration, number of generating units in the plant, operating conditions, unit sizes, and redundant measures. Experience to date has shown that plant availability and capacity factor are the highest in plants having multiple generation units capable of independent operation.

Operating steam conditions of the plant will be less than supercritical. This is in agreement with the ECAS Study (Reference 1), which showed that high efficiency plants producing low cost electricity are attainable, using moderate steam pressures. Further, steam conditions in the sub-critical region will allow maximum utilization of existing technology backed by extensive operating experience. The tentative steam conditions selected in this study, along with steam turbine rating, will be subject to economic review in Phase II.

The design will emphasize availability of power generation (even at reduced capacity) thru judicious auxiliary equipment selection, redundancy of critical control functions, and backup (manual) control systems.

Other factors indirectly influencing availability are human-related and can be controlled by programs in the design, manufacturing, construction, training and operating phases as well as an effective maintenance program.

The plant design program will include the development of a PERT schedule. The schedule shall include detail events and interfaces necessary through the periods of design, manufacture, construction, start-up and testing. Through this method of scheduling and updating of events, it will be possible to program efforts well in advance of the actual requirement. Job completion events are highlighted and task omissions, which repeatedly lead to high risk decisions, will be minimized.

Timely design reviews are included. As the design progresses, a detail scale model of the plant shall be produced and used in conjunction with the design reviews. Through the process of design reviews, Westinghouse Quality Assurance activity will identify critical human-performance functions in the manufacture and construction of the plant. Accordingly, strict quality assurance acceptance and check-off procedures can be established and implemented.

The prototype plant will include a full-scale operational test period prior to the manufacture of commercial plants. The plant design includes a test and design verification program that will allow necessary changes to be made prior to operation of succeeding commercial plants.

Plant availability can be improved by an awareness and understanding of the plant operation and equipment by the plant operating and maintenance personnel. To achieve this, the plant design shall include preparation of both Operating and Maintenance Manuals, along with the establishment of a formal training program that is made available to plant operating and maintenance personnel. This program will emphasize operating procedures, equipment limitations, preventive maintenance, spare parts stocking, and the effect of each upon plant availability.

# SECTION 2
# SYSTEM DESCRIPTION

For purposes of discussion, the combined cycle generating system can be divided into three major areas: the Fuel Treatment System, which treats the coal-derived liquid fuel, as delivered, so that it can be used in the combustion turbine; the Power Block which converts the fuel into electrical energy; and the Balance of Plant which includes all of the peripheral systems which service the fuel treatment system and the power block. Cycle studies utilizing the heat balances of the system components, ECAS Study (Reference 1) results and steam turbine design parameters, were performed to optimize and simplify the overall cycle. A high, overall efficiency is achieved with a cycle that can be realistically constructed and operated.

## 2.1 FUEL TREATMENT SYSTEM

The coal-derived oil, as delivered to the plant site, must be treated before it enters the power block. This treatment will consist of:

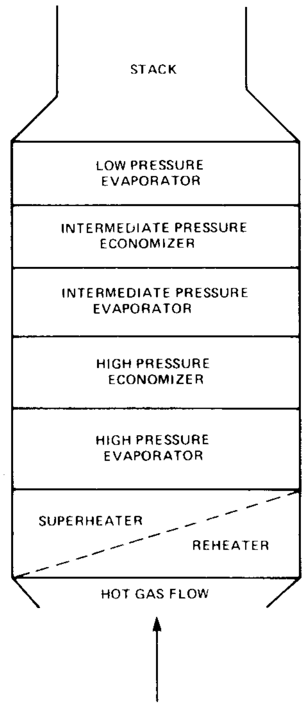
1. Heating to approximately $235^{O}F$ to satisfy minimum operating fuel nozzle viscosity of 70 SSU.

2. Water-wash to remove and reduce the sodium and potassium to a combined limit not to exceed 0.5 ppm. This limit is necessary to avoid a significant life reduction for the combustion turbine hot parts.

3. Injection of a vanadium inhibitor to minimize the corrosive effects of vanadium on life of hot parts, as required.

## 2.2 COMBINED CYCLE

The cycle employed in this plant burning coal-derived oil fuel is the conventional combined cycle, wherein a combustion gas turbine engine is integrated with a steam turbine through a heat recovery steam generator (HRSG). Although simply described, the combined cycle has many variations, each of which has a definite effect upon the overall performance. Among these variations are: main steam turbine throttle conditions; number and pressure levels of intermediate HRSG evaporator sections; supplemental firing of the combustion turbine exhaust gases; steam mix points; and auxiliary losses of the combustion gas turbine engine system, recovered and incorporated in the steam cycle. See Figure 2.2-1.




**HEAT RECOVERY STEAM GENERATOR**
**Figure 2.2-1**

From the ECAS study results (Reference 1), supplemental firing of the combustion turbine exhaust, yielded a lower cost of electricity, but at a penalty in efficiency. In this efficiency study, no supplemental firing will be used. Final benefits, if any, with regards to equipment selection and economic evaluation, will be performed in Phase II of this study.

The combined cycle centers upon the combustion gas turbine engine, where the thermal fuel energy is the input and shaft power and hot exhaust gases for steam generation are the output.

In the simple open cycle combustion gas turbine engine, air is compressed to approximately fifteen (15) atmospheres, and is discharged into a chamber where the high pressure air stream is divided. A small flow of high pressure air is taken outside the turbine and cooled before returning to the combustion turbine for the cooling of hot blading and other critical parts. Another portion of the high pressure compressor discharge air passes directly to the turbine for metal cooling.

The major portion of the compressor airflow is discharged into a combustor, where fuel is added and burned, thus raising the temperature. The hot high pressure gases are then expanded through a multi-stage turbine, developing shaft power to drive both the compressor and the electrical-generator.

The hot exhaust gases from the combustion turbine are ducted to an unfired Heat-Recovery Steam Generator (HRSG), for use with a steam turbine generator unit. Cycle studies supplemental to the ECAS work (Reference 1) were performed to optimize the energy transfer between the gas and steam cycle.

The HRSG selected in the optimization study, generates steam at three (3) progressively lower pressure levels, closely matching the gas energy level as it passes through the HRSG.

The energy transfer sections of the HRSG consist of a superheater-reheater, high pressure evaporator, high pressure economizer, intermediate pressure evaporator, intermediate pressure economizer and low pressure evaporator arranged in the gas flow path as shown in Figure 2.2-1. The main high pressure steam generated in the high pressure evaporator passes through the superheater and is raised in temperature before entering the high pressure (HP) turbine. The steam expands through the turbine to a pressure approximately one-fourth of the throttle pressure.

The intermediate pressure steam, exhausting from the HP turbine, mixes with saturated intermediate pressure steam generated in the intermediate pressure evaporator of the HRSG. This combined steam flow then passes through the reheater of the HRSG, where its temperature is raised to the same level as the superheater outlet steam temperature before entering the intermediate pressure (IP) turbine.

The steam, again, is partially expanded in the IP turbine. The discharge of the IP turbine is piped to the low pressure (LP) steam turbine to complete the expansion and then goes to a condenser pressure of 2.5" Hg absolute.

The two (2) economizer sections, HP and IP, take water from the low pressure drum which is raised in pressure by the boiler feedpump, and heat this water to the saturation temperature of the drum it is supplying.

The HRSG exhaust gas (stack) temperature of approximately 280$^{o}$F established in conjunction with the low pressure (28.2 psia) evaporator section, allows the gas side surface of the low pressure evaporator to operate safely above the sulfur dew point of the exhaust gas. For the 0.22 percent sulfur by weight in the fuel oil specified, the acid dew point of the exhaust gases is approximately 245$^{o}$F. The low pressure steam is used in a deaerating feedwater heater. Condensate from the condenser hotwell is pumped back through the gland and steam jet air ejector condensers to the deaerating heater(s). Circulating water for the condenser is cooled by a wet cooling tower, which also provides the cooling water for the plant heat exchangers.

# SECTION 3
# HEAT AND MATERIAL BALANCE

Cycle study results were confirmed by performing heat and material balances on each major piece of thermal equipment in the cycle. Balances performed on the final combustion and steam turbines, as well as the final selected overall combined cycle accounted for energy within expected tolerances.

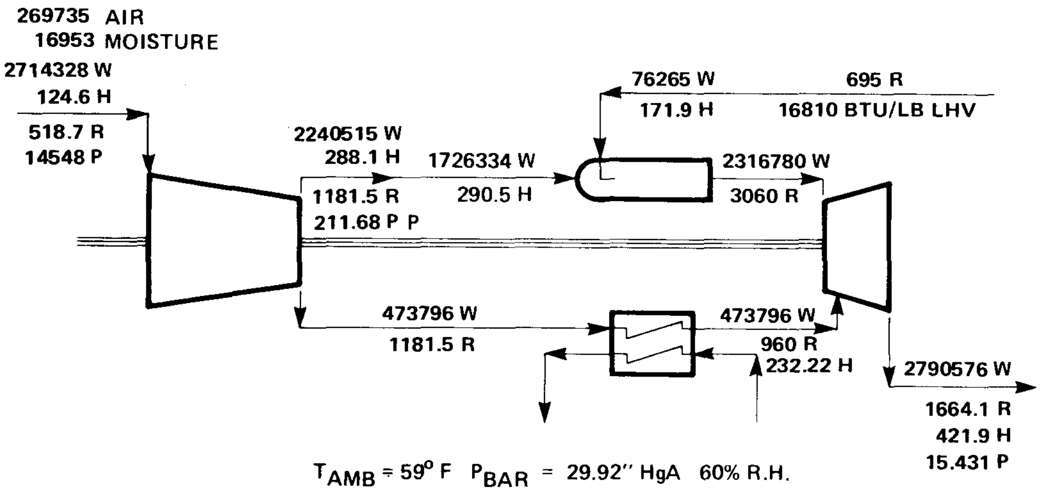
## 3.1 COMBUSTION GAS TURBINE ENGINE CYCLE

The combustion gas turbine engine heat and material balance shown on Figure 3.1-1 represents the turbine used in the coal-derived liquid fuel combined cycle. Atmospheric air at ISO conditions ($59^{o}$F and 29.92 In. HgA with 60 percent Relative Humidity) is compressed to a 15 to 1 pressure ratio. A portion of the compressed air is bled to the air heat exchanger where it is cooled prior to injection into critical components of the turbine expander hot section. The remaining compressed air is boosted in temperature by mixing with and burning the $235^{o}$F treated coal-derived liquid fuel raising the mixture temperature to $2600^{o}$F. The hot-gas mixture expands in the combustion turbine expander where the work of air compression is provided for the compressor. Energy in excess of that required for work of compression is used in a small part by the turbine bearings and in the larger part by an electric generator attached to the gas turbine shaft at the compressor end. The expander gas inlet temperature is $2600^{o}$F and the exhaust temperature is just over $1204^{o}$F. Inlet loss to the compressor is 1 percent (approximately 4 inches of water) while the exhaust back pressure is 5 percent (approximately 20 inches of water).

The power available at the turbine coupling of 125,166 KW includes the bearing losses for the turbine. The power available at the generator terminals results from deducting the generator and exciter bearing and electrical heat losses from the turbine coupling power.

## 3.2 STEAM TURBINE CYCLE

The steam turbine heat and material balance is shown on Figure 3.2-1. The quantities shown correspond to a coal-derived liquid combined cycle plant utilizing one combustion turbine and one steam turbine. However, the actual plant will contain two gas turbines and one large reheat steam turbine, and the complete plant quantities can be calculated to the proper values by multiplying flows and kilowatts from Figure 3.2-1 by two.



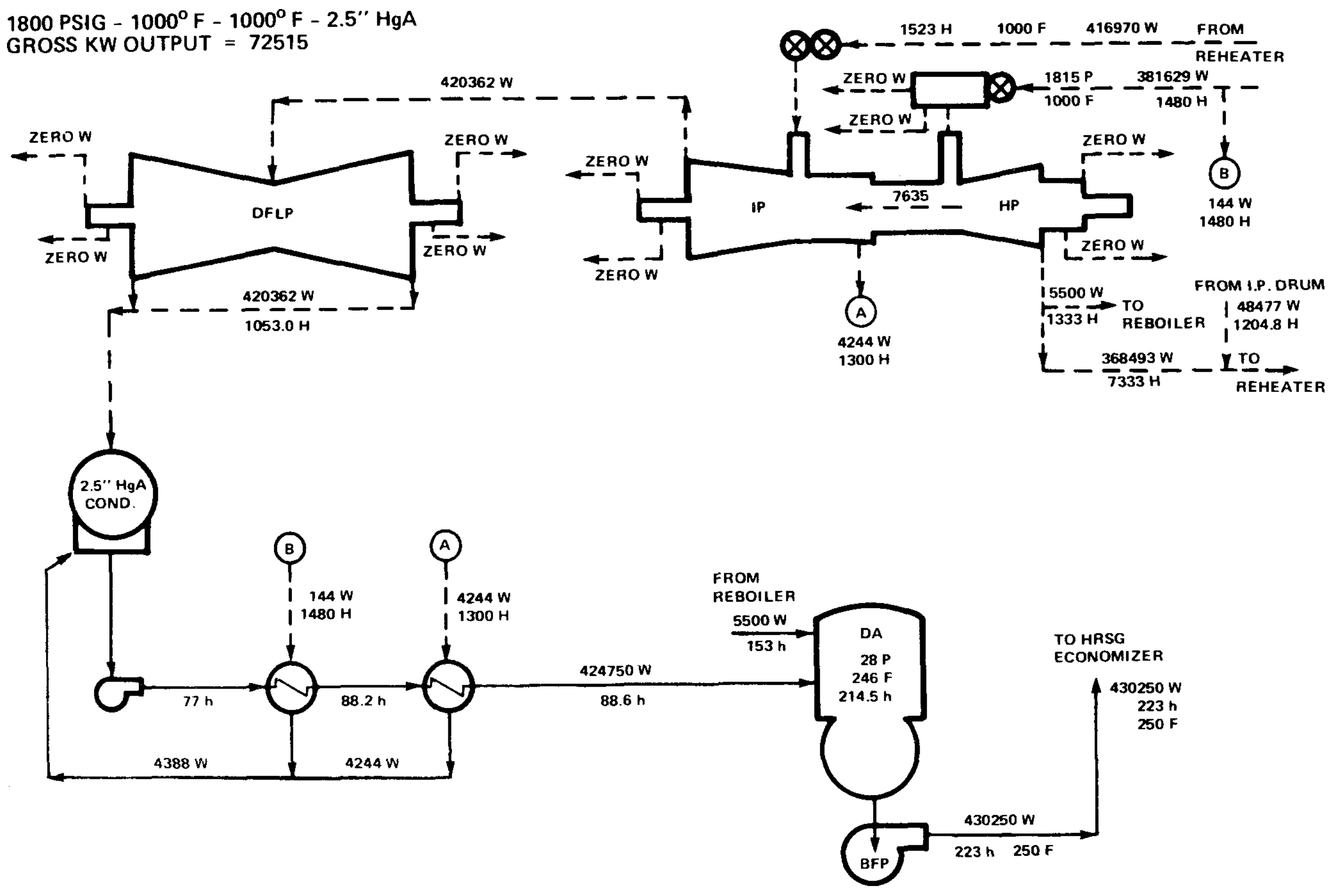

$T_{AMB}$ = 59° F  $P_{BAR}$ = 29.92" HgA  60% R.H.

125166 KW AT TURBINE COUPLING

2503 ELEC. & MECH. LOSSES

122663 KW AT GENERATOR TERMINALS

**GAS TURBINE HEAT AND MATERIAL BALANCE - COAL OIL COMBINED CYCLE**
**Figure 3.1-1**




**STEAM TURBINE MATERIAL BALANCE COAL OIL COMBINED CYCLE**
**Figure 3.2-1**

Figure 3.2-1 lists the major quantities for the steam turbine balance plus those interfacing with other components of the system that affect the steam turbine. Throttle flow at 1800 psig-1000$^{o}$F expands through the high pressure turbine. The high pressure turbine exhaust steam mixes with the dry and saturated intermediate pressure steam being generated in the HRSG and is reheated to 1000$^{o}$F before expansion in the intermediate and low pressure turbines. A minor portion of the high pressure exhaust steam is sent to a reboiler which is used to heat the coal-liquid fuel. No further steam extraction is required at this rated load point. The low pressure exhaust steam is condensed at 2.5 inches of Mercury absolute. The gross calculated power of the steam turbine is 72, 515 KW at the generator terminals. This includes the mechanical and electrical losses of the steam turbine-generator unit. Auxiliary electrical loads are not included as part of this energy balance.

## 3.3 OVERALL CYCLE

The heat and material balance of the overall cycle brings together the combustion and steam turbines, and includes the HRSG interface along with other auxiliary steam uses within the power block. For the purpose of the balance, only one (1) combustion turbine is shown. In the reference design plant, there will be two (2) combustion turbine-HRSG sets providing the steam for a single steam turbine generator unit.

The key interface within the combined cycle is the HRSG. The total exhaust gas flow of the combustion turbine flows through the HRSG, where the energy is transferred to water and steam for use in the steam turbine.

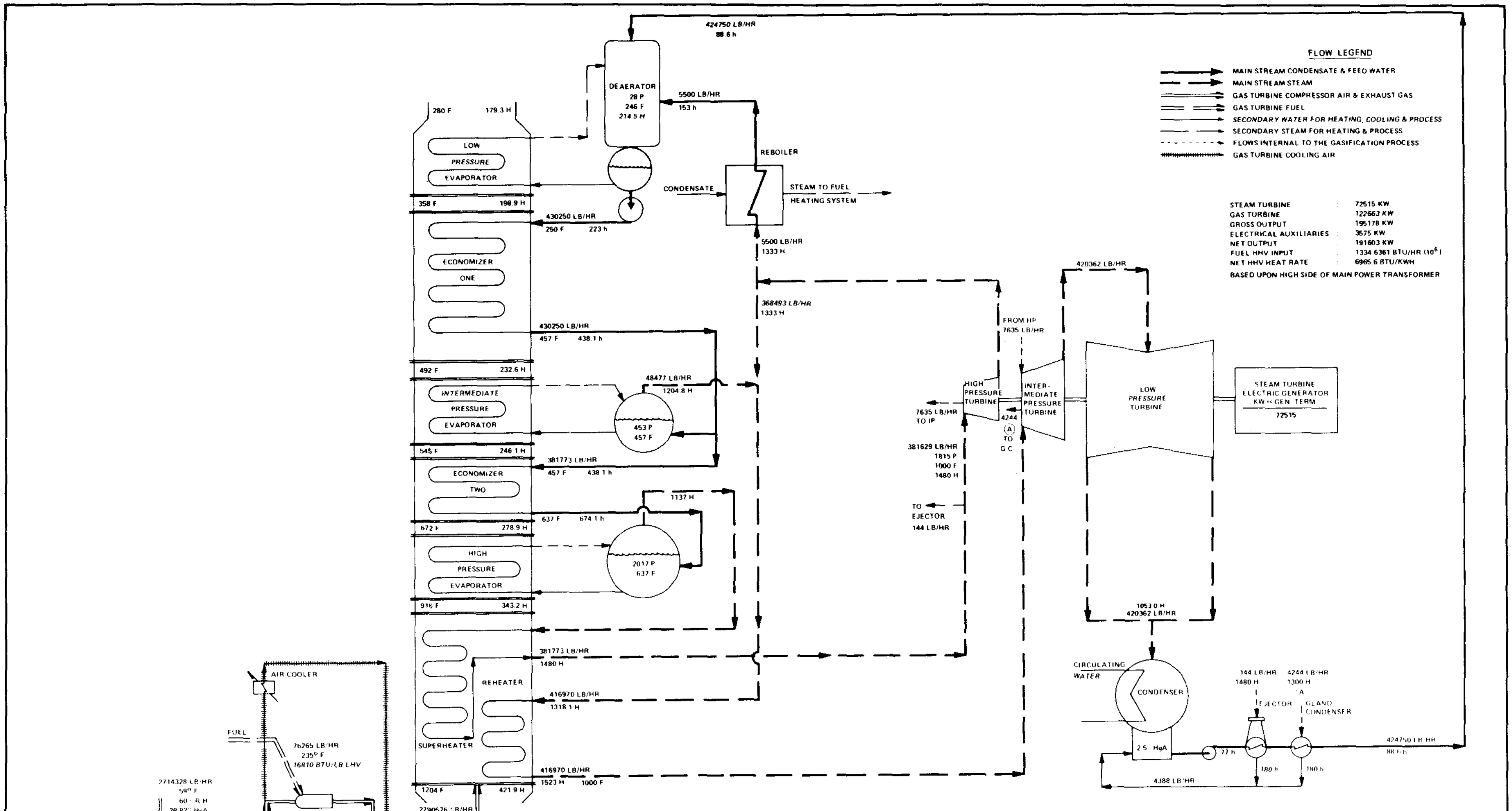
In calculating the energy transferred in the HRSG, a 1.5 percent radiation loss was used. Pressure-drops in the system were also accounted for.

The gross power output of the 1 to 1, combustion turbine-steam turbine plant is 195,178KW. This is the power available at the generator terminals. Total plant auxiliary electrical load was calculated at 3575KW. This value includes the following operating auxiliaries:

- Main stepup transformer losses
- Boiler feedpump
- Fuel oil pumps
- Lube oil pumps
- Circulating water pumps
- Cooling tower fans
- Condensate pumps
- HRSG circulating pumps
- Control power

The net plant power per the heat balance, Figure 3.3-1, is therefore 195,178 - 3,575 or 191,603KW. With the HHV fuel input to the combustion turbine being 1334.64 x $10^6$ Btu/Hr., the net plant heat rate is 6,966 Btu/KwH (HHV).

As stated earlier, the reference plant will consist of two (2) combustion turbines. Therefore, its net plant rating will be twice that displayed by the heat balance, or 383,206KW. The net plant heat rate will remain unchanged at 6,966 Btu/KwH (HHV).




**COAL DERIVED LIQUID FUEL COMBINED CYCLE SCHEMATIC AIR-COOLED COMBUSTION TURBINE**

**Figure 3.3-1**

# SECTION 4
# FUEL SPECIFICATION

The untreated liquid fuel to be delivered to the combined cycle plant shall have the following physical and chemical properties, typical of a coal-derived liquid fuel:

| | |
|---|---|
| API Gravity | -2:3 |
| Viscosity, SSU @ $210^{o}$F | 160 |
| Sulfur, percent wt. | 0.22 |
| Nitrogen, percent wt. | 1.0 |
| Hydrogen, percent wt. | 7.58 |
| Carbon, percent wt. | 90.0 |
| H/C | 1.01 |
| Aromatics, percent wt. | 76.3 |
| Pour Point, F | 86 |
| Carbon Residue, percent | 4.4 |
| V, ppm wt. | 0.5 |
| Na + K, ppm wt. | 10.0 |
| Heating value, Btu/Lb, HHV | 17,500. |

# SECTION 5
# POWER BLOCK

The equipment referred to as part of the Power Block includes the combustion and steam turbine-generator units and the major equipments directly associated such as the main steam condenser, feedwater heaters, boiler feedpumps, HRSGs and instrument air system.

## 5.1 COMBUSTION GAS TURBINE-GENERATOR

The combustion gas turbine engine-generator unit will be an integrally-designed plant with all support and control systems such that the interfaces to the remainder of the power block or plant be limited to:

a. Control signals in and out;

b. Fuel in;

c. Electric power out;

d. Exhaust energy out;

e. Cooling water in and out;

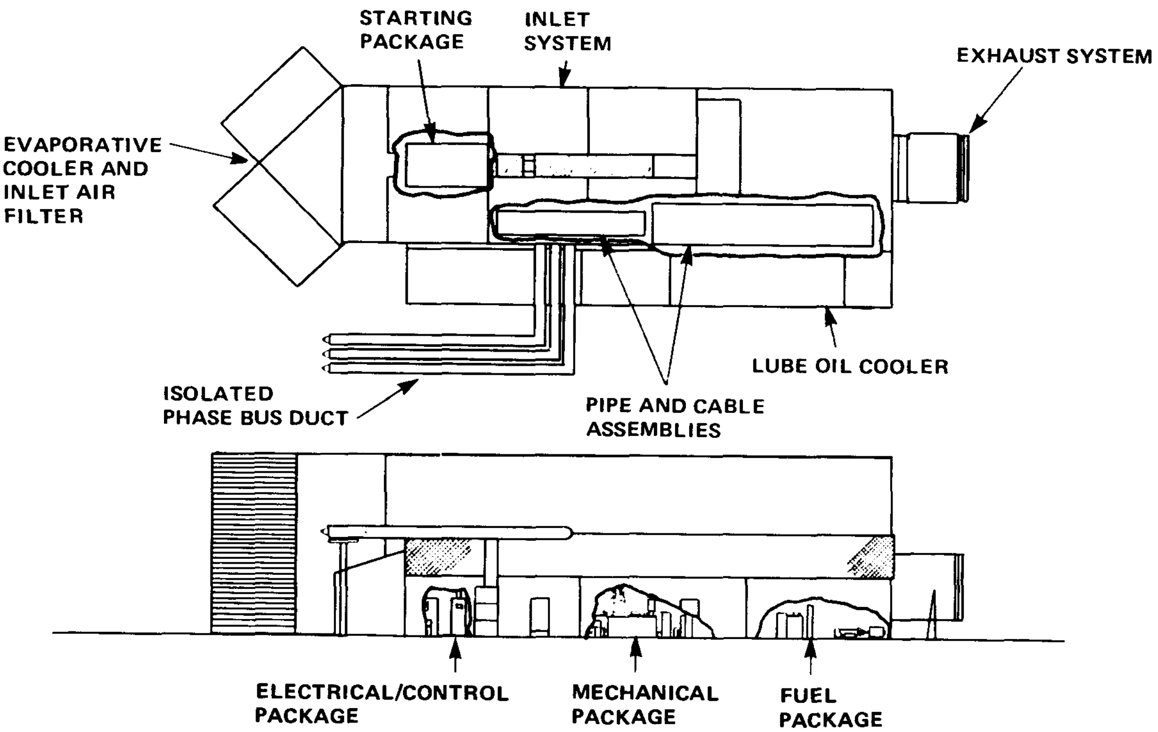
f. Generator gases in;

g. Compressor air in.

A typical layout of the equipment in this portion of the plant is shown in Figure 5.1-1.

Both the turbine and generator will be designed to operate at 3600 rpm, with drive through the cold-end of the turbine, permitting direct connection through a reliable solid type coupling. Air to the compressor of the combustion turbine will be ducted axially in an elevated system over the generator to a top oriented inlet to the compressor. The duct system will contain the necessary acoustic treatment for airborne noise emitted from the duct opening and radiated noise transmitted through the duct walls.

In addition, the inlet air-duct system will be fitted with an inlet air filter and an evaporative air cooler. These two (2) auxiliary appurtances can have a major effect on maintaining a high operating plant efficiency. The primary function of the inlet air filter is to prevent dust particles and other airborne impurities from entering the machine.




**GAS TURBINE -GENERATOR PLANT**
**Figure 5.1-1**

The original concern of dust and impurities entering the machine, was that they would collect on the blading of the axial flow compressor, causing fouling and a significant deterioration of power output. When internal cooling air passages in turbine vanes and blades were introduced on turbines having higher firing temperatures, the concern for air cleanliness became even greater. Fouling or plugging of cooling passages in the turbine area can lead to metal hot spots, and eventual mechanical failure.

On Westinghouse turbines, the cooling air flow for critical passages is taken from the compressor discharge external to the machine for cooling, and since the mass flow is small, relative to the compressor intake flow, it is filtered independently of the compressor inlet air. This arrangement has the following advantages for both the user and the manufacturer:

1. Cleanliness to the cooling air system was ensured, even without an inlet air filter installed.

2. Redundancy and an even cleaner cooling air system would result on machines having an inlet filter.

3. Partial restoration of power lost due to compressor fouling is possible by injecting a dry agent, such as ground pecan shells, into the air stream of the operating unit. The separate turbine cooling air filter permits this procedure without adverse effect to the cooling system.

Turbines operating at the higher firing temperatures become more susceptible to corrosion attack by the alkaline metals, sodium and potassium. It is necessary to control the quantitative amount of these elements in the turbine through fuel oil selection and/or treatment and filtering of the inlet air for baseload applications.

More recently, with operating time on the latest generation of turbines increasing and turbine conditions being examined, there is rise to the possibility of even other airborne contaminants causing corrosion of turbine hot parts. It is important to include the inlet air filter in the basic plant design.

As there are many choices of filter media with a wide range of efficiency, the media can be selected to suit the site ambient and/or operating limits as they may dictate.

The evaporative air cooler reduces the high ambient temperature effect on the combustion turbine power output (10 percent for a $20^{o}F$ temperature change) by humidifying the inlet air and lowering its temperature to within a few degrees of the ambient wet bulb temperature. When operating, the evaporative cooler also acts as a water wash type filter to the incoming air.

The turbine will be fitted with a combustion system (piping, nozzles and combustors) capable of burning the treated coal-derived liquid fuel. The exhaust gases from the turbine will be ducted axially to the HRSG, thus keeping duct pressure drop losses to a minimum. Included as part of the ducting is an expansion joint, that permits independent thermal growth of the turbine and ducting, without exceeding mechanical stress limits of each.

Because of the inherent capability of the combustion turbine to develop more power at reduced ambients, the design of the turbine and generator will permit an excess of ISO rating to be generated without exceeding mechanical and thermal limits.

The generator will be a conventionally hydrogen-cooled machine packaged to minimize field installation time. In addition to the hydrogen gas system, a carbon dioxide system is provided to permit safe purging of the generator, as required.

The hydrogen and carbon dioxide systems are mounted in an auxiliary control enclosure on the side of the generator. This subassembly is factory assembled, but shipped separately.

The exciter for the generator will be of the brushless type, consisting of three (3) major components. These are: the permanent magnet generator, the ac exciter, and the rotating rectifier. These components are all mounted on a single shaft in an "exciter package", located on the starting equipment end of the generator.

Isolated phase bus duct will be used to carry the electrical energy from the generator out to the switchyard. The bus duct will be connected to top-mounted bushings at the generator and will then be directed out to the side of the machine before turning axially toward the switchyard. This arrangement minimizes possible interference when maintenance is performed on the starting package, exciter or generator.

The packaging (maximum factory assembly) will be accomplished within the limits of rail transportation, but most importantly, will be designed to minimize package interfaces and maximize functional or fluid system factory testing of individual packages.

Each package assembly has an enclosure complete with access doors, lighting, heating and ventilation. The turbine unit will also be housed in a field erected enclosure.

Even though the turbine, generator and their associated auxiliary packages will be installed within a large central turbine-generator room, the individual enclosures serve several important functions:

1. They provide an acoustic barrier for radiated noise being emitted from operating equipment.

2. They allow for separate environmental control, unique to the equipment enclosed.

3. On factory assembled packages, the enclosure serves as a shipping container.

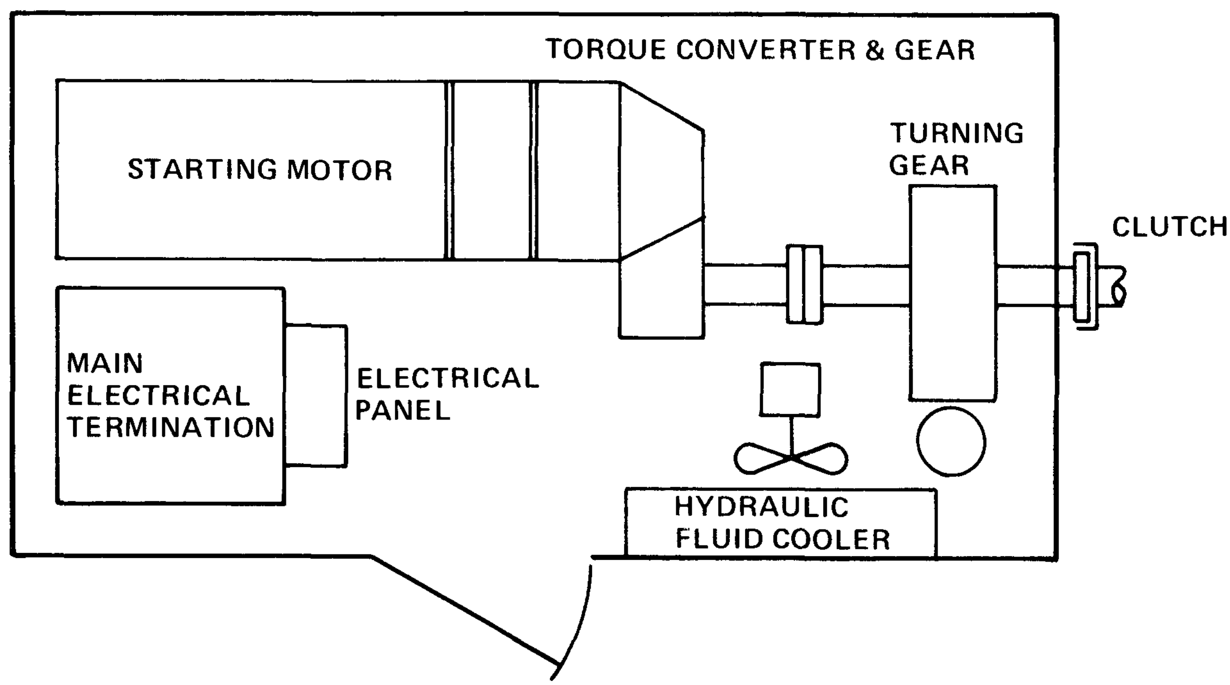
An optional Halon gas fire-protection system will be designed into each enclosure, with the exception of the starting package. This type of system suppresses flame, while maintaining a life-supporting atmosphere requiring no release time delay, as in other systems.

The major auxiliary packages of the combustion turbine-generator unit are:

*STARTING PACKAGE*

This package has several functions applicable to the main turbine-generating shafting. First, it provides the breakaway torque necessary to accelerate the shafting from a standstill. Secondly, it provides the necessary torque to accelerate the shaft system to ignition and self-sustaining speed of the combustion turbine. Thirdly, it provides the torque necessary to slow roll the shaft system after a shutdown, to prevent thermal distortion or bowing of the rotor shaft.

An additional starting function, that of supplying atomizing air to the fuel oil nozzles during the ignition period, is incorporated into this package. The equipment necessary to provide these functions is assembled on a common steel fabricated bedplate and consists of: an electric motor, torque converter and hydraulic fluid cooling system, turning gear, clutch and atomizing air blower. The package will have its own electrical distribution system, requiring only a single AC and DC feeder source. Figure 5.1-2 shows the layout of this package.



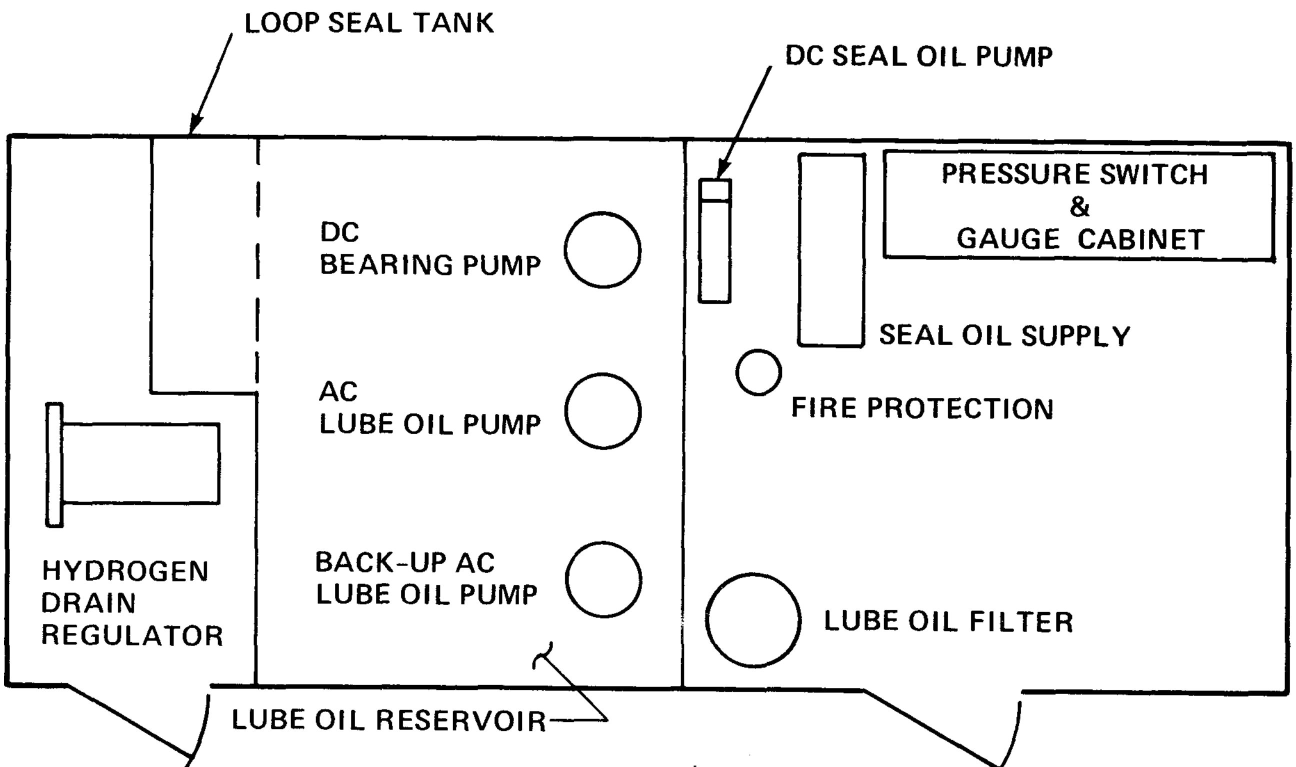

**STARTING PACKAGE**
**Figure 5.1-2**

*MECHANICAL PACKAGE*

This package assembles the lube oil system, generator seal oil system, a pressure switch and gauge cabinet assembly (part of the control system) and the dry chemical storage for the turbine exhaust bearing fire protection system on a fabricated steel bedplate. The arrangement of the equipment is shown by Figure 5.1-3.

All components of the lube oil and generator seal oil system are mounted internally to the package, except the lube oil cooler. This shell and tube cooler will be mounted horizontally on the roof of the package. Its location will not interfere with the vertical removal space required for maintenance on the vertical reservoir mounted lube oil pumps.

The pressure switch and gauge assembly houses in a central cabinet pressure gauges, pressure regulators, switches and transducers for the display and control of the various unit-related fluid systems. It serves as the interface panel between fluid and electrical control signals. Space within this package will be set aside so that water or steam injection equipment for $NO_x$ emission control can be added should it be necessary.




MECHANICAL PACKAGE
Figure 5.1-3

*FUEL PACKAGE*

This package will have assembled within it, all of the major components of the fuel systems. All filters, valves, pumps, interconnecting piping, associated controls and interconnecting conduit and tubing will be included.

It is advantageous to group the fuel systems in a separate package, to minimize and simplify gas detection systems, fire protection systems and the classification of associated electrical equipment, as required by code, or desired by the customer.

Both distillate fuel and the primary fuel, a coal-derived oil, will be delivered to the fuel package from the balance of plant system. The heavier coal-derived oil, as delivered, will have been heated to a temperature corresponding to a viscosity of 100 SSU. This will permit using the same pump, filters and control valves for the distillate oil and the coal-derived liquid fuels.

Unit space heaters will not be included in this package, as the installed components are not sensitive to freeze conditions. Electrical heat tracing will be installed on the fuel oil lines to maintain a minimum line viscosity under low ambient conditions. As this package adjoins the turbine enclosure, it is a suitable location for the Halon gas fire protection spheres of the turbine enclosure.

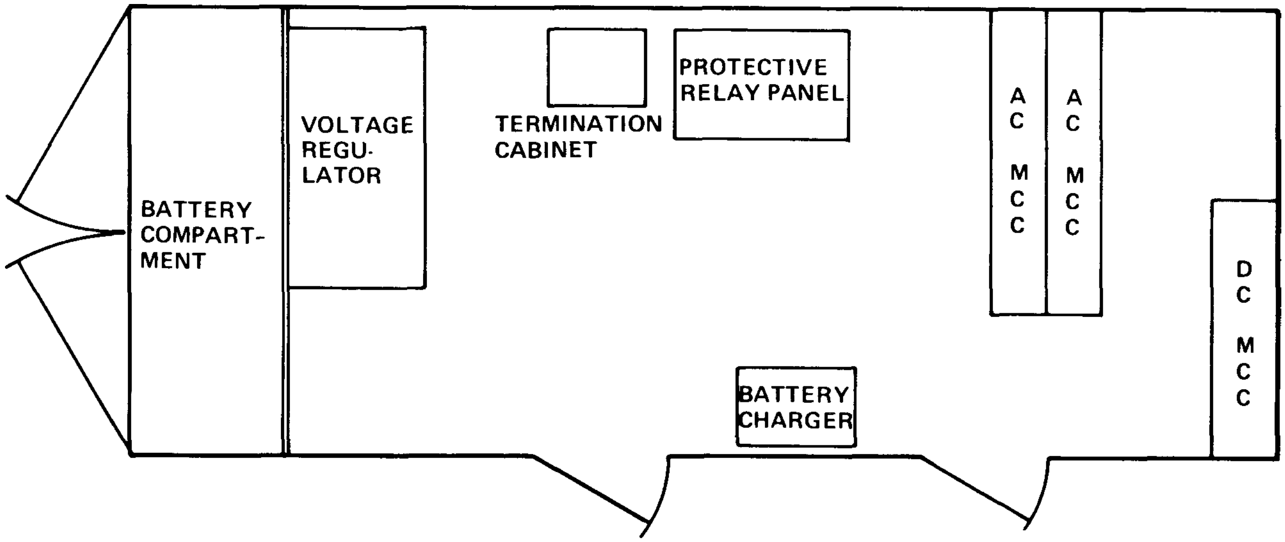
Space only will be provided in this package for additive injection into the liquid fuel system for control of opacity of the exhaust stack gases should it become necessary to add for any reason in the future.

*ELECTRICAL AND CONTROL PACKAGE*

Assembled on a common bedplate are the major electrical and control components of the unit. These items include the AC and DC motor control centers, the generator voltage regulator, protective relay panel, emergency batteries for the unit, along with a rectifier battery charger and an interface panel for making the control connections to the central control room. The typical arrangement of this package is presented in Figure 5.1-4.

The AC and DC motor control center houses the breakers, motor starters, overload protection and relays necessary to interface the various auxiliary loads of the plant with the main control system.

The voltage regulator, part of the generator excitation system, is a static system, used to control the excitation of the brushless shaft driven exciter, thus the output of the generator. Although located in the package, the regulator control mode (manual or automatic) and the necessary raise-lower control functions will be selected at the central control panel.




**ELECTRICAL AND CONTROL PACKAGE**
**Figure 5.1-4**

The protective relay panel mounts the relays required to properly protect the generator from an electrical malfunction. This includes: generator differential, generator ground fault, negative sequence, overcurrent, and reverse power relay. The panel is designed, however, to accommodate additional protective relays, such as transformer differential, voltage balance and/or loss of field relays. Relay trips will be displayed locally by the respective relays and will also be annunciated in the central control room.

The electrical equipment installed in this package is sensitive to climatic conditions, such as temperature changes, humidity, and dust. Therefore, the atmosphere within this package will be controlled by the use of air conditioners and electric space heaters.

## 5.2 HEAT RECOVERY STEAM GENERATOR

The HRSG will receive its energy input from the combustion turbine in the form of hot exhaust gas. The gas will be at the temperature as discharged from the turbine, and will not receive any additional energy through supplemental firing.

The function of the HRSG is to recover this otherwise lost turbine exhaust energy and transform it into steam and heated feedwater through appropriate heat transfer surface for ultimate use in the steam turbine. For this study, a forced circulation type HRSG will be used for rapid load follow and more effective factory packaging of the tube surface. Gas flow from the turbine will enter the HRSG axially and be directed upward to the heat transfer surface by turning vanes. The heat transfer sections of the HRSG will have horizontal tubes of serpentine design with the sections stacked in a vertical gas flow path. A schematic arrangement of the HRSG is displayed in Figure 5.2-1.

The high-pressure and intermediate-pressure steam drums will be vertically oriented and fitted with internal moisture separators to prevent moisture carryover. The low-pressure evaporator will be connected to a storage drum and deaerating feedwater heater assembly.

Separate motor-driven circulating pumps in the evaporator circuits will move the water from the drums into the respective evaporator sections. The boiler feedpump takes its suction from the low-pressure storage drum. As the heat transfer process on the water side of the evaporator section is isothermal, the log mean temperature difference is the same for a counterflow or parallel flow design. The design will be parallel flow to permit operation at part loads under natural circulation in the event of a circulating pump malfunction.

A complete water management analysis of the HRSG system must be part of the detail design process under all operating modes to ensure proper equipment sizing and selection. Areas having particular interest are:

1. Control of drum swell upon startup. This includes sizing of the drum and blowdown systems; selection of drum level controls and the feedwater valve; and establishment of proper operating sequence of pumps and valves.

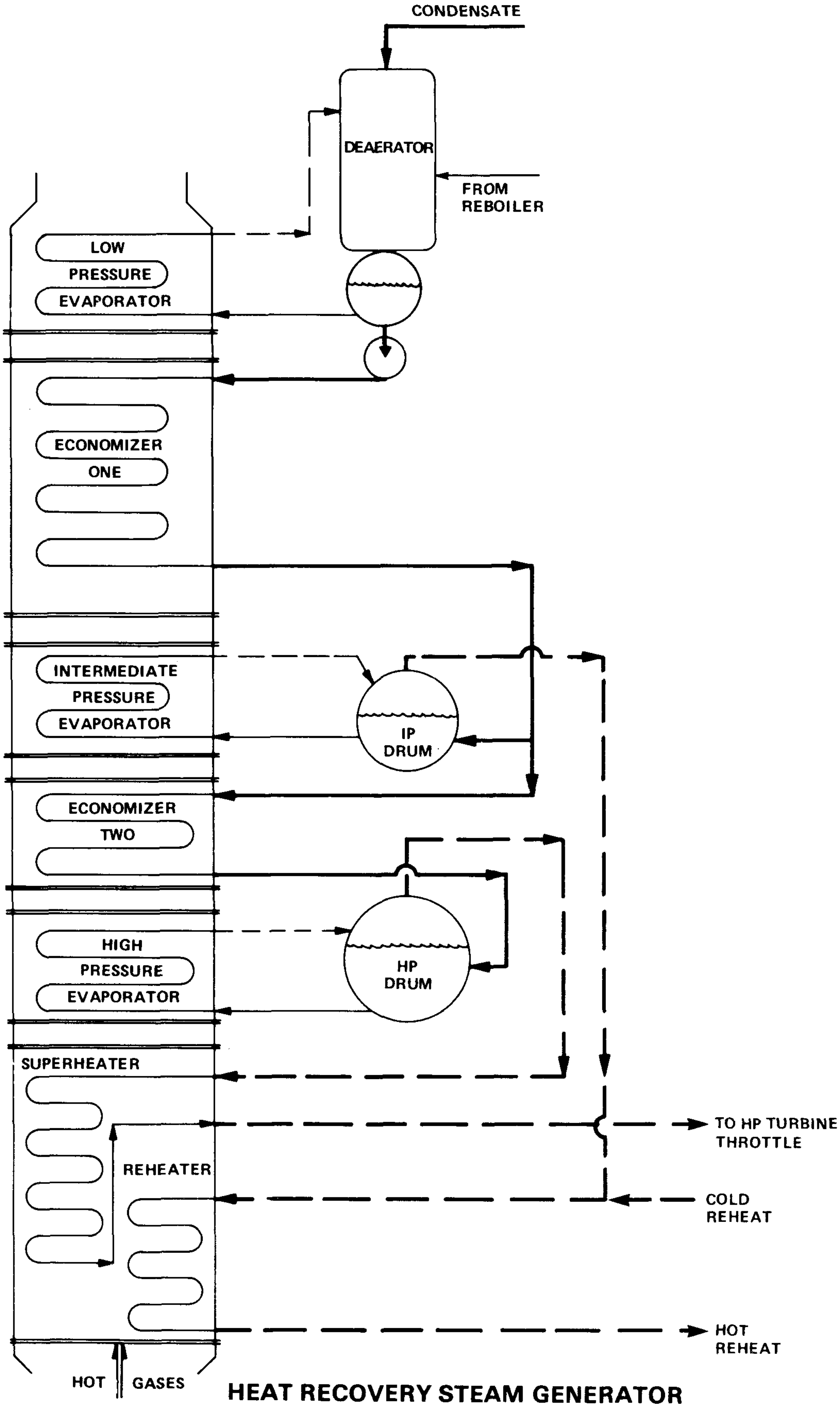
2. High pressure circuit circulation rate. Circulating pump selection, along with sizing of the pipe system and installed components, must provide proper circulation rates at all times to prevent "boil dry" situations.

3. Control of the boiler feedpump Net Pressure Suction Head (NPSH) particularly during a hot, ready-to-start condition. This includes providing a means of maintaining pressure in the deaerating low-pressure drum by high-pressure steam addition and shutoff of condensate flow to reduce chilling of the drum water.

4. Maintaining a minimum low-pressure evaporator tube surface temperature so as to avoid the sulfur dewpoint during all phases of operation.

5. Feedwater flow control of the economizer sections to avoid excessive steaming conditions at any operating point.

6. Failure analysis of water and steam circuits to ensure compliance with ASME codes for proper relief devices.




**HEAT RECOVERY STEAM GENERATOR**
**Figure 5.2-1**

The HRSG will match the operating modes of the plant and the combustion turbine without exceeding operating limits of any component or the system, as a whole. Where an operational limit of a component is approached, a control interface is established so as to realign systems to permit continued operation within limits.

The total exhaust gas flow of the combustion turbine will pass through the HRSG. Bypass stacks and associated louvres or dampers will not be employed. The simple straight-through gas flow holds performance at the highest level, since leakage, characteristic of the bypass arrangement, will not exist.

The HRSG will normally be operated in the wet (full of water) condition. During certain standby conditions, it will be desirable to retain heat in the HRSG for a hot, ready-to-start condition, or, for freeze protection. To this end, the exhaust stack of the HRSG will be fitted with a motor-operated, open/closed cover; and electric heaters will be installed.

To minimize corrosion of the internal dry surfaces during short, idle periods when the HRSG is full, or in prolonged periods when it is drained and empty, an inert gas system will be used. Pump seals and valves within the system, protected by the inert gas, will be selected, keeping in mind secondary leakage of the inert gas, and that it must be minimal.

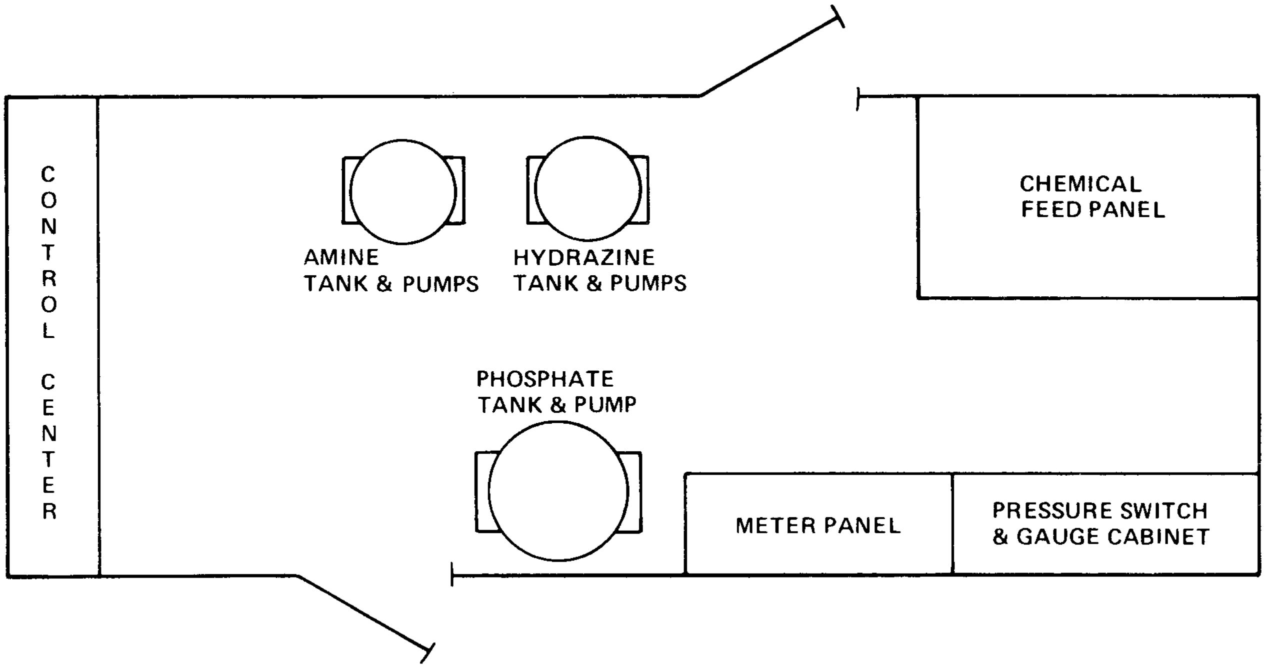
Access ladders, platforms and walkways are provided to permit operator access to all elevated operating components.

The design of the HRSG follows the packaging philosophy used throughout the plant. This includes maximum factory pre-assembly of ductwork and breaching between the turbine and HRSG inlet; the tubed heat transfer sections; the exhaust stack; steam drums; and, an auxiliary package.

The HRSG auxiliary package contains associated systems and equipment having numerous, mechanical and electrical interconnections between components within the system, making it desirable for factory assembly and checkout.

Further, many of the components and systems are sensitive to the hot environment near the HRSG and/or to freezing, making a controlled environment installation an operational advantage. A typical arrangement of the equipment in this package is shown in Figure 5.2-2.

The principal system, assembled into the HRSG auxiliary package, is the chemical feed system. The purpose of this system is to monitor boiler water and chemically treat it to maintain the required water chemistry. The system is comprised of sample coolers, an instrument panel, chemical tanks and injection pumps. Also included in the package is a pressure switch and gauge cabinet, which houses the pneumatic, hydraulic and electrical control devices for the HRSG; a meter panel to indicate steam and condensate




**HRSG AUXILIARY PACKAGE**
**Figure 5.2-2**

flows for each HRSG; and a control center for the distribution of electrical power and control of auxiliary loads associated with the HRSG.

Environmental control of this package will be provided by a weathertight enclosure, containing thermostatically operated ventilation fans and electric space heaters.

Package fabrication will include:

1. Open floor grating to permit heating of space below floor level containing fluid lines.

2. Equipment drains manifolded to a single floor drain point.

3. Isolating partition and floor splash plate to prevent moisture from entering electrical control center.

The emergency chemical contamination shower will be located external to the package, so as to avoid interference with internally-installed electrical apparatus.

## 5.3 STEAM TURBINE, GENERATOR AND EXCITER

The steam turbine-generator unit will be axially arranged on a common shaft system. The steam turbine will be a two (2)-case unit, having a common high-pressure/ intermediate-pressure cylinder, and one (1) low-pressure cylinder having two (2) sets of exhaust blading. This type unit is known as a tandem (in-line) compound (more than one cylinder) double-flow condensing reheat unit.

The high-pressure/intermediate-pressure turbine is of the combination impulse and reaction type. The steam enters the high-pressure element through two throttle valve steam chest assemblies, one located at each side of the turbine. The steam chest outlets are connected to the HP-IP casing through inlet sleeves, each connected to its nozzle chamber by a slip joint. Half of the inlet sleeve connections are in the base and half are in the cover. The steam passes through the impulse stage and high-pressure blading to the reheater, through two exhaust openings in the outer casing base.

The steam returns from the reheater to the intermediate-pressure element through two interceptor-reheat stop valve assemblies, one located at each side of the turbine. The four outlets of these valve assemblies are connected to the IP casing inlet sleeves which are connected to the inner casing by slip joints. The steam passes through the intermediate-pressure element reaction blading to one exhaust opening in the outer casing cover. This exhaust opening is connected through a separate crossover pipe to an opening in the casing cover of the low-pressure turbine. A pressure balance expansion joint is provided at the low-pressure turbine end of the crossover pipe to accommodate the thermal expansion of the crossover pipe and at the same time balance the internal pressure force. The double flow low-pressure turbine is a straight reaction double flow type element with steam entering at the center of the blade path and flowing toward an exhaust opening at each end, then downward into a combined exhaust into the condenser. Openings are provided in the casings through which steam may be extracted for feedwater heating. The unit is provided with two steam chest-throttle valve assemblies, one located at each side of the turbine casing. Each steam chest contains four plug-type governing valves which are controlled by an electric hydraulic governing system through individual servo-actuators, one mounted on each governing valve. The throttle valves, which are located horizontally at one end of each steam chest, are also controlled by servo-actuators.

The generator driven by the steam turbine will be a hydrogen inner-cooled machine with an air-cooled brushless exciter. With the inner cooled generator, hydrogen gas is circulated through openings in the rotor and stator coils to improve the dissipation of the heat generated. This is in addition to the cooling of the stator laminations and the rotor forging and end turn retaining ring found in the conventionally cooled machine.

The brushless exciter and the hydrogen and carbon dioxide gas systems will be the same as those for the generator used with the combustion turbine.

The steam turbine and the generator and exciter will be factory assembled as required to establish and verify operating clearances. Due to the physical size of the assembled equipment exceeding shipping limits, it will be necessary to ship subassemblies to the installation site for final assembly.

At points where the rotor penetrates the outer cylinders, some means is needed to prevent leakage of air into or steam from the cylinders. Glands, with their labyrinth type seal rings, and the gland sealing steam system, are provided to perform this function. The gland sealing steam system contains the valves to regulate sealing steam pressure to the glands, and a desuperheater, to control sealing steam temperature to the glands of the low-pressure turbine.

Air operated drain valves are provided for the main inlet steam piping, the first-stage chamber, the HP-IP outer cylinder and the reheat-inlet steam piping drain systems. These valves will be operated automatically through the various operating modes to ensure that no water enters the turbine.

The exhaust of the low-pressure turbine will have a spray water system that will prevent overheating of the turbine exhaust from low-speed operation up to approximately ten percent load. This spray system will also be used to control exhaust temperature when large amounts of steam are being bypassed directly to the condenser.

The steam turbine will be limited in operating conditions to the following:

1. The turbine will be designed with a 5 percent throttle flow margin above the flow required to meet the maximum rated output with extraction points in service. This procedure is standard in allowing for manufacturing tolerances.

2. With governing valves wide open and the extraction points in operation, the turbine will safely operate at 105 percent of its rated throttle pressure.

3. The maximum operating exhaust pressure is 5" Hg absolute.

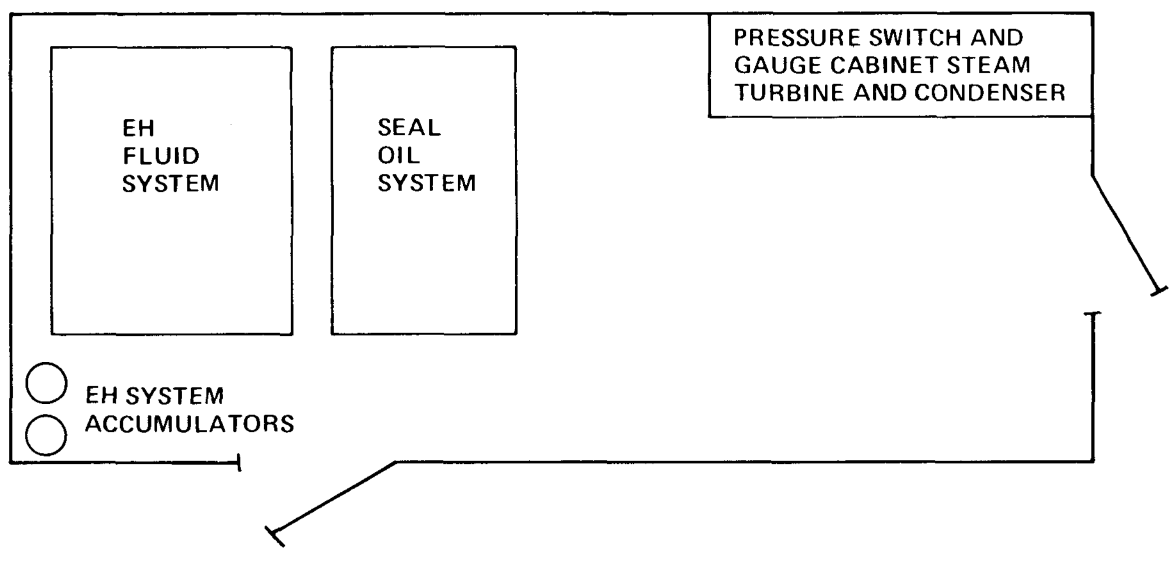
4. The limiting exhaust casing temperature is $250^{\circ}$F.

There are two fluid systems provided for in the operational control of the steam turbine-generator unit, the EH fluid system and the lube and seal oil system. Each system is separate and individual, but they are interlocked through an interface emergency trip valve to ensure a unified effective trip system. The function of the EH high-pressure fluid system is to provide a motive force for positioning the turbine steam valves in response to an electrical control signal. The lube and seal oil system satisfies the requirements for bearing lubrication and the generator hydrogen seals. In addition, this system provides the medium to hydraulically operate the mechanical overspeed trip mechanism and manual trip lever.

Due to the physical size of the lube and seal oil system, packaging and shop assembly of this system to the same degree as was done on the combustion turbine units is prohibitive. Therefore, design effort will focus upon a minimum of subassemblies for minimum interfacing. Major lube system subassemblies will include the lube oil reservoir which mount the main oil pump ejector, backup and emergency lube oil pumps, backup seal oil pump-vapor extractor and associated interconnecting pipe; and the shell and tube, oil to water lube oil coolers.

A common fabricated base assembly will contain the remaining auxiliary mechanical equipment. This equipment includes the EH high-pressure fluid system, seal oil system, steam turbine and condenser pressure switch and gauge assemblies.

A typical skid arrangement of this equipment is given in Figure 5.3-1. The high working pressure of the EH system necessitates the use of a synthetic fluid. The fluid is stored in a stainless steel reservoir assembly, upon which is mounted a duplicate system of fluid pumps, controls, filters and heat exchangers. The system is so arranged that one pump and one set of the various control components function, while the duplicate set serves as a standby system. Because of the relative demands (quantity, pressure and temperature) between the bearing and hydrogen seals, on generating units of this size, it is more desirable to have seal oil conditioning separate from the bearing oil supply.




**STEAM TURBINE AUXILIARY PACKAGE**
**Figure 5.3-1**

The generator hydrogen seal oil system consists of booster pumps, coolers, filters, and regulating valves. This system receives oil from the lube oil system and conditions it to the temperature and pressure requirements of the shaft seals.

A combined steam turbine-condenser pressure switch and gauge assembly mounts in a central cabinet, pressure gauges, regulators, switches and transducers for the display and control of the related fluid systems. A bulkhead will be provided for fluid connections, and a terminal board for all external electrical connections.

An enclosure containing lighting, heating and ventilation will house the above auxiliary equipment. Provision will be made to add a Halon gas fire protection system as an option.

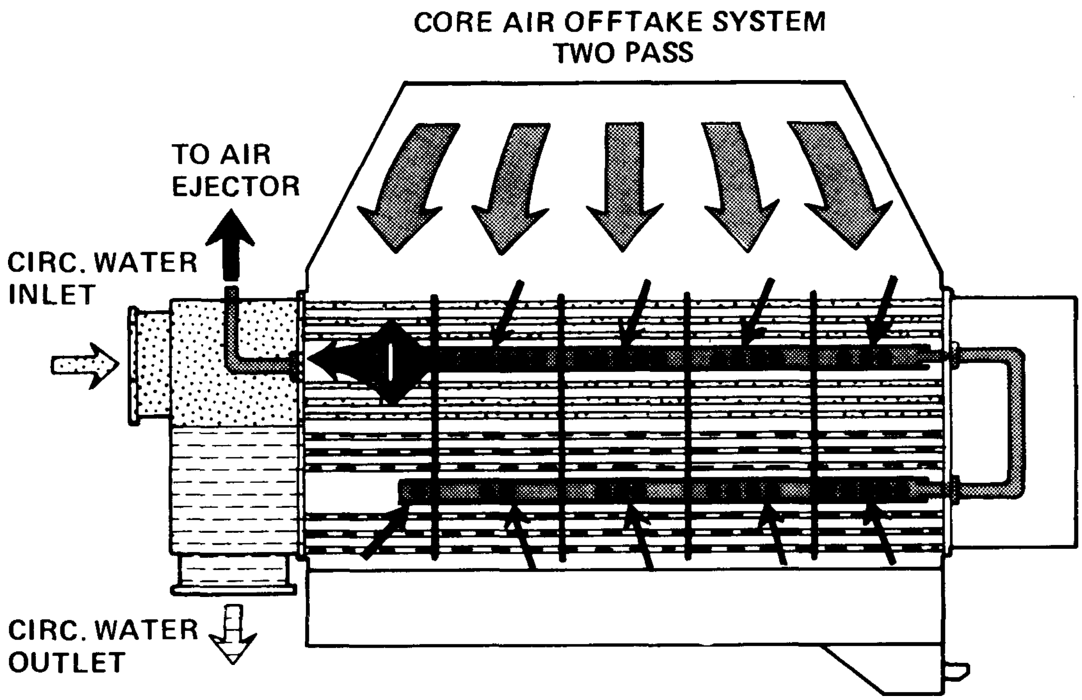
An electrical and control package, essentially a duplicate of that provided on the combustion turbine-generator, and described earlier will also be provided for the steam turbine-generator.

## 5.4 MAIN CONDENSER AND CONDENSATE PUMPS

The condenser will be floor-mounted beneath the exhaust opening of the low-pressure steam turbine. Mounting will be such that the tubes are horizontal and normal to the turbine axis. Connection to the exhaust cylinder of the steam turbine will be through an expansion joint, allowing independent thermal movement of each without exceeding mechanical limits. The tube bundles will be arranged using the Westinghouse radial flow concept, assuring an evenly distributed steam flow pattern radially inward to the core. With an air offtake located in the core, equal venting of all portions of the tube banks is thus assured.

The mixture of air and steam reaching the core enters the air offtake pipe through orifices carefully sized to control the venting along the length. Air and gases flow through the vent pipe to the cold end where a baffle arranged transversely to the flow causes the vent mixture to cross several rows of the coldest tubes before it enters the offtake pipe leading to the air ejectors. This final pass over the coldest tubes reduces the amount of steam in the vented gases to a minimum.

This air offtake system is illustrated in Figure 5.4-1. Another important function of the condenser is to ensure that the leaving condensate is free of dissolved gases, particularly oxygen, which can cause corrosion in other parts of the cycle. Since the quantity of gas that a liquid can hold in solution depends on the nearness of the liquid temperature to its saturation temperature, if there is no subcooling, there can be no gas. Therefore, the condensate formed must be as close as possible to the saturation temperature. The radial flow design accomplishes this.




TWO-PASS RECTANGULAR SURFACE CONDENSER
Figure 5.4-1

There are two (2) condenser arrangements available in reference to circulating water flow. First, there is the single-pass design where the circulating water from the balance of plant enters one end of the condenser, passes through the tubes and exits on the other end. Then there is the two (2)-pass condenser, where the circulating water passes through the upper half tubes of the bundle in one direction and then reverses its flow through the lower tubes before exiting.

There are technical considerations associated with each arrangement, with each having an economic value for final optimization of the heat rejection system.

This analysis was performed in the ECAS advanced steam cycle study and a two (2)-pass condenser was selected for use on an equivalent rated steam unit. The condenser used in this plant will therefore be of the two (2)-pass design. Manholes will be provided in the waterboxes and shell, permitting maintenance access to the tubes and hotwell. The condenser air offtakes, discussed earlier, are connected to steam driven air ejectors. A large volume hogging ejector is used for air removal and establishing a vacuum during startup, while the primary ejectors are used to remove the air during operation. The exhaust of the hogging ejector will be directed to the atmosphere, since it has only limited operation. The exhaust of the primary ejectors is directed to an air ejector condenser, where the latent heat of condensation is transferred to the condensate coming from the hotwell.

The condenser shell will be provided with auxiliary connections as follows:

1. A connection for steam bypassed from the turbine.
2. A breakable diaphragm as an emergency limit to the exhaust pressure imposed on the steam turbine and condenser.
3. Drain and vent connections as required by the steam turbine. Connections with a fluid temperature above 650°F will be connected by a thermal sleeve.

Waterboxes will be divided so as to allow tube cleaning, inspection and repair, if necessary, by reducing load rather than a total unit outage. In addition, the hotwell of the condenser will be divided to assist in locating tube leakage. This is accomplished by taking conductivity readings in the line from each hotwell compartment to the condensate pumps.

The condenser will be factory assembled, with the tube bundles shipped as an assembly. The condenser shell will be shipped in pre-fabricated sections for final field assembly and welding.

The condensate pumps will be motor-driven centrifugal pumps of the vertical can type. Three (3) 50 percent capacity pumps will be installed, with one of the pumps being a backup. The characteristic head curve of each pump will be identical and each will be capable of parallel operation. Each pump will be fitted with a washable suction strainer and a discharge check valve, the installed elevation of the latter being below the hotwell condensate level assuring full lines to the idle pump(s) and avoiding liquid surges on startup.

## 5.5 FEEDWATER HEATING

Condensate pumped from the condenser hotwell to the HRSG recovers energy from the steam used to power the air ejectors and to seal the glands on the steam turbine shafting. This is accomplished by passing the condensate through two (2) separate series connected heat exchangers — the air ejector condenser and the gland steam condenser.

The air ejector condenser will be of the shell and tube design, with the condensate passing through the tubes. The condenser will have a trapped drain allowing the collected condensate to be returned to the main condenser hotwell. The condenser will have an orificed vent for operating at atmospheric pressure.

The gland steam condenser construction will be similar to that of the air ejector condenser. A motor driven exhauster, connected to the shell side of the gland condenser, removes the air and other non-condensible vapors that have leaked through the glands, and discharges them to the atmosphere. This condenser must operate at a sufficient vacuum so as to maintain the slightly sub-atmospheric pressure at the glands. The drain of this condenser is also trapped, and the condensate returned to the main condenser hotwell. All heat exchangers will be constructed in accordance with the ASME Unfired Pressure Vessel Code, Section VIII.

## 5.6 BOILER FEEDPUMPS

The function of the boiler feedpump is to raise the pressure of the condensate flow to satisfy HRSG and steam system losses and yet produce rated throttle pressure.

Each HRSG will have a full capacity (approximately 50 percent of the steam turbine throttle flow) boiler feedpump which will take its suction from the storage tank of the deaerating feedwater heater and discharge the high-pressure water for use in both intermediate and high-pressure evaporator sections of the HRSG for the production of steam.

Each pump will be suitable for outdoor installation adjacent to the HRSG so as to minimize suction line losses. The NPSH of the pump will be sufficient to avoid cavitation under all modes of operation, which include steady-state and transient variations of suction pressure and temperature.

## 5.7 INSTRUMENT AIR SYSTEM

The instrument air system supplies the air used as the motive force and the control medium by the pneumatic valves throughout the power block. As a part of the control system, the instrument air supply will be dry, oil free, and reliable with regard to source.

The central source for all instrument air will be an air package. This package will be self-contained and capable of supplying all of the air required, from its air compressors. This is necessary since no bleed air will be available from the gas turbine compressors when the plant is in a cold standby or ready-to-start operating mode.

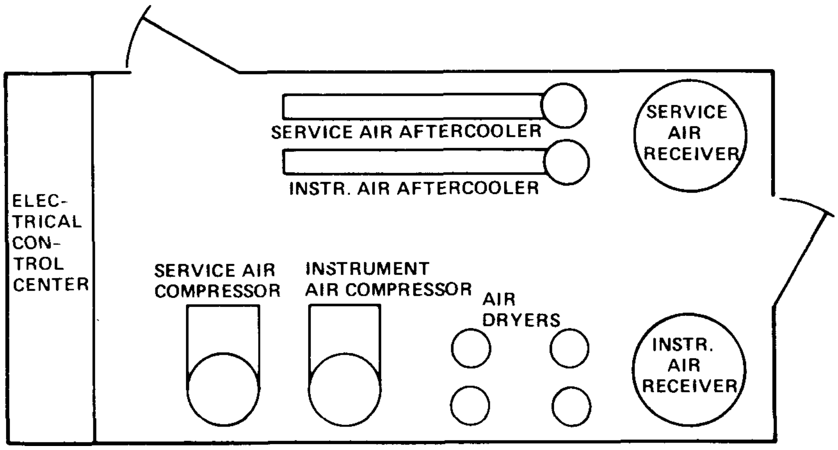
The air package assembly is made up of two (2) independent systems; the instrument air system and the service air system. Each system is complete, with regard to compressor, aftercooler, air separator and receiver tank. The instrument air system also has an air dryer, with a backup to positively assure dry air in the event of a malfunction. Both systems will be interconnected to provide maximum operating flexibility along with redundancy for the instrument air supply. These systems are described in greater detail in the plant reference design.

In addition to the air handling equipment, the air package assembly is completed by an electrical control center and an enclosure having lighting, ventilation and heating. A typical equipment arrangement of the air package is given in Figure 5.7-1.

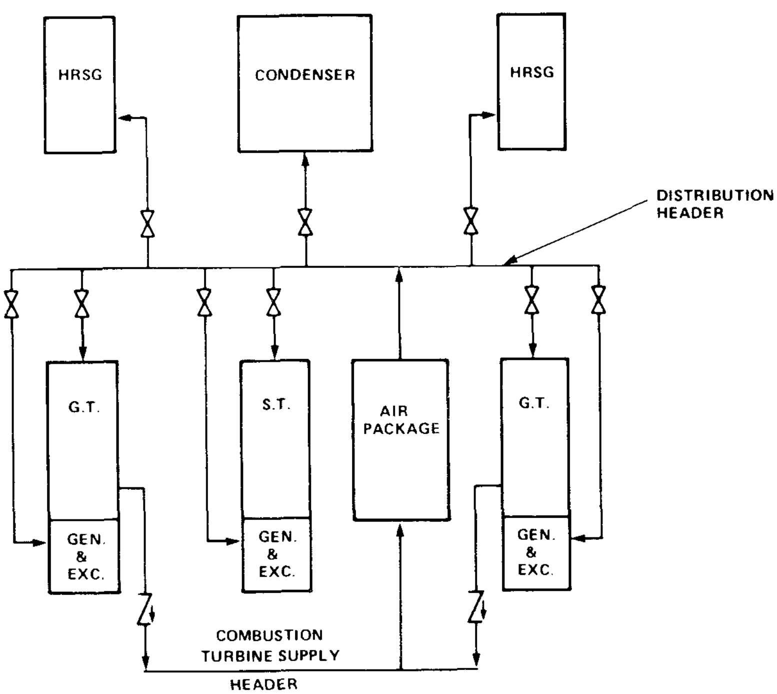
Since compressed air is part of the combustion turbine cycle, it will be used as the principal supply to the air package, when the plant is operating. This places the air package compressors in a standby condition. By manifolding the air supply from the combustion turbines to each of the air systems, the total operating air requirements will be shared by the operating units. This arrangement offers several steps of redundant supply.

Dry instrument air from the air package is delivered to the pneumatic devices of each major component from a distribution header. Shutoff valves for maintenance will be on each line from the distribution header. In addition, each pneumatically operated valve having a manual bypass will have shutoff valves in the pneumatic lines to permit valve maintenance. Piping or tubing used in the system downstream of the air package will be non-corrosive.

A schematic of instrument air within the power block is shown in Figure 5.7-2.




**PLANT AIR PACKAGE**
**Figure 5.7-1**




**INSTRUMENT AIR SYSTEM**
**Figure 5.7-2**

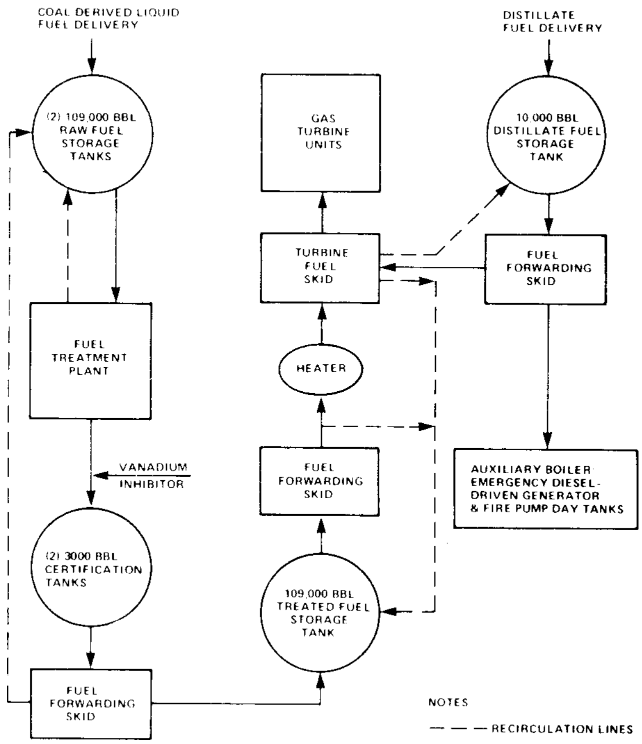
# SECTION 6
# BALANCE OF PLANT

The balance of plant includes the primary cycle auxiliary mechanical equipment and supporting subsystems necessary for the operation of the plant. Included are the:

- coal-derived liquid fuel receiving
- storage and transfer equipment
- a coal-derived liquid fuel treatment subsystem for reducing contaminants and particulate to acceptable limits for combustion in the gas turbines
- distillate fuel receiving
- storage and transfer equipment for gas turbine startup and shutdown, for the auxiliary boiler, for emergency diesel-driven generator and fire pump operation
- boiler feedwater storage and treatment equipment for maintaining water quality limits necessary for plant operation
- a heat rejection system including a cooling tower, circulating equipment, and chemical treatment equipment for algae control
- a waste handling system providing for the collection, treatment and disposal of storm water, fuel treatment subsystem effluent, and other plant wastes.

## 6.1 LIQUID FUEL RECEIVING, STORAGE AND FORWARDING

A fuel handling system is provided for receiving, storaging and forwarding of the coal-derived liquid fuel. The system design is based on pipeline delivery of the fuel to the plant, a daily fuel consumption rate of 42.4 lbs per second at 100 percent plant capacity factor, and a total on-site storage capacity of raw and treated fuel for thirty (30) days continuous plant operation. A Simplified Fuel Process Flow Diagram of the liquid fuel receiving, storage, and forwarding system is shown in Figure 6.1-1. The location of the coal-derived liquid fuel receiving, storage and transfer equipment described in this Section is shown on the Plot Plan in Section 7 of this Report.




**SIMPLIFIED FUEL PROCESS FLOW DIAGRAM**
**Figure 6.1-1**

The raw fuel is delivered via a pipeline to the station and stored in two 109,000 BBL Raw Fuel Storage Tanks. The tanks are designed to API Standards and furnished with steam-heated coils to maintain the raw fuel at 100°F. The heat is required to maintain fluidity of the fuel. In order to reduce heat loss, the tanks are insulated with a monolithic layer of polyurethane foam, coated with a silicone rubber for protection against the weather.

The raw fuel is supplied by gravity to the fuel treatment plant and, following treatment and vanadium inhibitor injection, is temporarily stored in one of two 3000 BBL Treated Fuel Certification Tanks. Prior to transfer to the Treated Fuel Storage Tank, fuel samples are extracted from the Certification Tanks to determine fuel acceptably. This ensures against contamination in the treated Fuel Storage Tank resulting from a malfunction in the fuel treatment plant.

Two 350 gpm 100 percent capacity Fuel Transfer Pumps transfer the acceptable fuel from the Treated Fuel Certification Tanks to the 109,000 BBL main Treated Fuel Storage Tank. This tank is identical in design to the Raw Fuel Storage Tanks and is also provided with steam heating coils to maintain the fuel temperature at 150°F.

Two Fuel Forwarding Skids are provided to supply the treated liquid fuel, or when required, distillate fuel, directly from their respective storage tank to the Gas Turbine

Fuel Skid without use of intermediate day tanks. Each Forwarding Skid is connected by separate No. 2 distillate and treated liquid fuel oil lines to both gas Turbine Fuel Skids located adjacent to the gas turbines. Separate circulation headers are provided for both types of fuel. In addition, a heater is provided in the treated liquid fuel line running to the Gas Turbine Fuel Skid in order to maintain the treated liquid fuel at the desired viscosity for proper fuel atomization.

All piping to and from the units is above ground and located at the outer perimeter of the plant away from electrical equipment. All coal-derived liquid fuel lines are steam-heat traced to maintain the fuel at 100$^{o}$F.

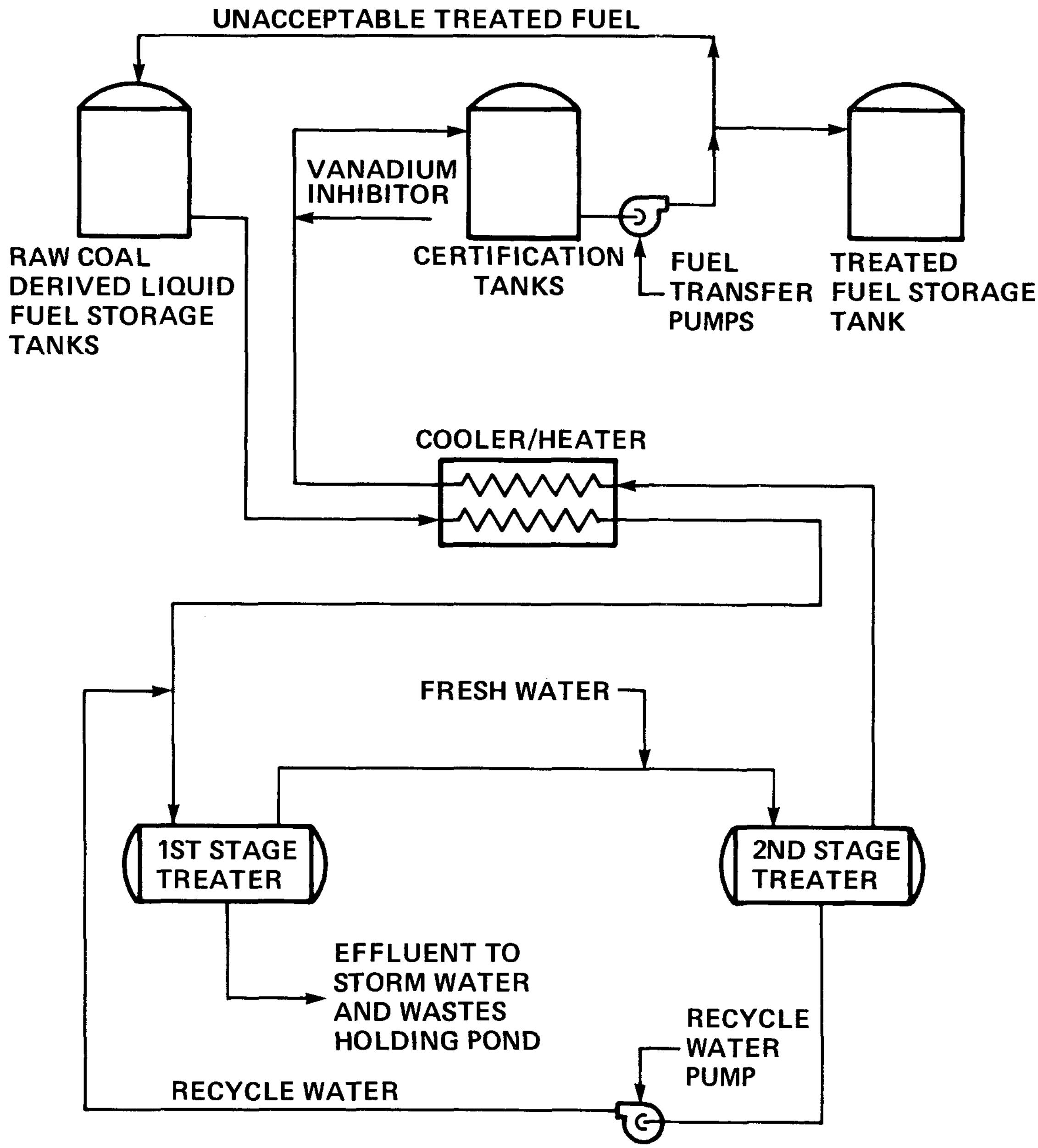
The heating steam necessary to maintain the required fuel temperatures in the fuel tanks, fuel treatment plant, piping and at the gas turbine nozzles is generated in a Reboiler. This provides heating steam from a closed system eliminating the danger of contaminating the HRSG feedwater system. The Reboiler, which provides 10,000 lbs/hr saturated steam at 90 psia, receives heating steam from either the cold reheat piping or the Auxiliary Boiler. The heating steam condensate is returned to the HRSG feedwater system. During operating periods when steam is supplied from the Auxiliary Boiler, the condensate is then returned to the Auxiliary Boiler Deaerator. The condensate from the fuel heating system is collected in a receiver and returned to the Reboiler.

## 6.2 LIQUID FUEL TREATMENT SYSTEM

The raw coal-derived liquid fuel as delivered to the plant must be treated to reduce the level of alkali metals and particulates prior to burning in the gas turbines. Two techniques for treating the fuel are electrostatic precipitation and centrifugation. In both techniques, water washing is used to dissolve the soluble contaminants and flush out suspended solids. A third technique being considered for fuel treatment is electrostatic filtering. The electrostatic filtering technique uses electro-mechanical methods to reduce the level of contaminants, but this technique is still in its infancy and requires further development. Since electrostatic precipitation has been widely used for the treatment of heavy fuels, it was selected for use in Phase I of this study. A Simplified Fuel Treatment Process Flow Diagram is shown in Figure 6.2-1.

It should be noted that the coal-derived liquid fuel, as defined, is not characteristic of conventional fuels and only a conceptual approach was taken during Phase I to describe the fuel treatment system. Accordingly in Phase II of this study, a greater emphasis will be placed on the area of fuel treatment.

The fuel treatment plant is designed to process 13,000 barrels per day of raw coal-derived liquid fuel in a two-stage electrostatic desalter to reduce the sodium and potassium concentrations to less than 0.5 ppm. The raw fuel at 100$^{o}$F is supplied by gravity to the fuel treatment facility where it undergoes two stages of heating to 300$^{o}$F and is then discharged to the first-stage treater tank. Fresh water is introduced to




**SIMPLIFIED FUEL TREATMENT PROCESS FLOW DIAGRAM**
**Figure 6.2-1**

the fuel leaving the first-stage treater prior to the second-stage treater and is uniformly dispersed throughout the fuel. The water is then separated and mixed with the raw fuel being pumped to the first-stage treater, separated again and withdrawn as effluent. The resulting dispersion of fresh water and particulate matter is exposed to a high potential electric field in both treatment stages, promoting the coalescence of water droplets which rise to the surface. The fuel is purified to the extent that the water droplets make contact with the contaminants. The two stages of treatment have been assumed to accomplish satisfactory purification.

A magnesium compound is injected into the fuel following the two stages of washing to minimize the high-temperature corrosive effects of vanadium in the fuel.

The treated fuel is then discharged to one of the two 3000-barrel Certification Tanks where fuel samples are obtained for analysis. An atomic absorption spectro-photometer is used to analyze the metal content in the fuel. After analysis, the acceptable fuel is forwarded to the Treated Fuel Storage Tank. Should a batch be determined unacceptable, it is returned to the Raw Fuel Storage Tanks. Fuel transfer from the Certification Tanks to the Treated Fuel Storage Tank is accomplished with two 350 gpm positive-displacement pumps. Recirculation loops are provided to route fuel back to the storage tanks, if required, during desalter startup, fuel system cleanup or other phases of operation.

## 6.3 STARTUP AND/OR STANDBY FUEL SYSTEM

A No. 2 distillate fuel oil system is provided for the startup and shutdown requirements of the gas turbines, auxiliary boiler, and emergency diesel engine-driven generator and fire pump. The system is designed to provide start/stop operations of the gas turbines for sixty (60) days, based on an assumed 260 plant starts per year, and for continuous operation of the auxiliary boiler for thirty (30) days. (Figure 6.1-1 provides a Simplified Fuel Process Flow Diagram.)

The No. 2 distillate fuel oil is stored in a 15,000-barrel capacity cone roof, flat bottom storage tank located inside a diked area as shown on the Plot Plan, in Section 7, together with a fuel forwarding skid. The fuel forwarding skid discharges to the gas turbine fuel skids located adjacent to each gas turbine in the station building. Recirculation lines returning to the storage tank are provided.

Rail and tank truck unloading facilities are provided for unloading the No. 2 distillate fuel. The rail unloading facility has two hose stations allowing two 23,000-gallon tank cars to be unloaded simultaneously through the bottom. The hose stations are located to permit connection to the two tank cars spotted in the unloading area without shifting. The unloading station is connected to a header in a trench and to two 50 percent capacity, 500 gpm screw-type pumps for fuel unloading and transfer. A separate unloading station is provided for tank trucks with two 50 percent capacity, 200 gpm gear-type pumps provided for this service.

In Phase I of this study additional distillate fuel receiving, storage, and forwarding equipment for use as a full load, standby fuel for burning in the gas turbines has not been considered.

## 6.4 BOILER FEEDWATER TREATING AND STORAGE

In order to prevent deposits of solids on the internal surfaces of the boiler and to prevent carryover of dissolved solids to the steam turbine, resulting in decreased thermal efficiency and damage to the steam turbine, treatment of the boiler feedwater is of prime consideration in power plant design. Included in this section is the pretreatment of station makeup water and demineralization of HRSG makeup water.

The equipment for the boiler feedwater pretreatment plant consists of a circular steel concrete bottom upflow clarifier, three circular steel valveless gravity filters, clearwells, and the necessary number of service water transfer pumps to supply water to the HRSG feedwater makeup demineralizers and fuel treatment plant. Auxiliary equipment includes the necessary lime and coagulant chemical feeders, tanks, chemical feed pumps and chlorination system for prechlorination of raw water, flow split box, recycle pump, supply headers, piping, valve flow meters, instruments and controls.

The pretreatment equipment is sized for a net flow of 95 gpm, considering:

- 40 gpm required for fuel treatment
- 35 gpm required by the demineralizers for HRSG makeup (plus regeneration water)
- Necessary flow for sludge blowdown and filter backwash requirements.

The clarifier, filters and clearwells are installed outdoors adjacent to the water treatment building housing the demineralizer equipment and laboratory. Chemical feed equipment pumps and controls are installed at the ground floor level inside the building with lime and alum storage above the chemical feed room. The water treatment building is located just west of the plant island.

The demineralizer system consists of a two-train arrangement with each train sized to deliver 35 gpm of process water and HRSG feedwater makeup. Each demineralizer train is provided with an activated carbon purifier, strong acid cation unit, strong base anion unit, and a mixed bed polishing unit. The primary cation and anion exchangers are designed for a 24-hour period between regenerations. The capacity of each train's mixed bed unit is such that it is exhausted and requires regeneration between the ninth and tenth regeneration of the primary units. In normal operation, one train is in service with the other train regenerated and maintained in standby condition. The composition of demineralizer effluent is shown in the following table.

WATER ANALYSIS AFTER DEMINERALIZATION

| Constituent | | Composition After Demineralization |
|---|---|---|
| Calcium ($Ca^{++}$) | ppm as $CaCO_3$ | 0 |
| Magnesium ($Mg^{++}$) | " | 0 |
| Sodium ($Na^{+}$) | " | 0.05 |
| Potasium ($K^{+}$) | " | 0.05 |
| Hydroxide ($OH^{-}$) | " | 0.05 |
| Carbonate ($CO_3^{--}$) | " | 0 |
| Sulfate ($SO_4^{--}$) | " | 0 |
| Chloride ($Cl^{-}$) | " | 0.05 |
| Nitrate ($NO_3^{-}$) | " | 0 |
| Fluoride ($F^{-}$) | " | 0 |
| Total Hardness | " | 0 |
| Methylorange (MO) (total alkalinity) | " | 0.1 |
| Silica ($SiO_2$) | " | 0.01 |
| Iron (Fe) Total | " | |
| Manganese (Mn) | " | 0 |
| Turbidity (JTU) | | 0-1 |
| Color (Pt Units) | | 0 |
| Carbon Dioxide ($CO_2$) | ppm as $CO_2$ | 0 |
| pH | | 6.5 - 7.5 |

Control systems and auxiliary mechanical equipment for the boiler feedwater treatment system are designed for remote manual or semi-automatic pushbutton operation. All equipment is located inside the water treatment building. The strong acid and caustic storage tanks are located outdoors adjacent to the water treatment building. Demineralized effluent is pumped to the 100,000-gallon condensate storage tank, located near the control building, for use as makeup to the HRSG feedwater system and auxiliary boiler feedwater system.

## 6.5 COOLING WATER SYSTEM

Closed-loop type cooling water systems are used at the station for condensing exhaust steam from the steam turbine, for cooling equipment, and for cooling other cycle fluid streams. The collected heat is rejected to the atmosphere by an evaporative type cooling tower.

The major portion of the cooling load is the condensing of exhaust steam from the steam turbine. The equipment in this loop consists of a cooling tower with basin, two 50 percent capacity circulating water pumps, a main condenser and the large diameter circulating water ducts. The main circulating water system is described in Subsection 6.5.1 of this report.

The cooling of equipment and other cycle fluid streams is done in parallel with the main condenser and uses the same water source. Cooling water pumps supply water to the equipment and heat exchangers located throughout the plant. The cooling water is pumped in a separate line from the cooling tower basin, through the equipment, and returned to the cooling tower via the main condenser outlet circulating water duct. The auxiliary cooling water system is described in Subsection 6.5.2 of this Report.

The source for the plant cooling water supply is the North River, which is assumed to be a tributary of the Mississippi-Missouri River Basin. For design purposes in this study the assumed North River water analysis, tabulated on Table 6.5-1, from the ECAS study (Reference 1) was used. The ECAS study water analysis makes identical assumptions for the source of plant cooling water supply and is based on 1974 Water Quality Records for the states of Missouri, Illinois, Indiana and Ohio.

River water is pumped into the clean water holding pond, located parallel to the North River northwest of the plant island by three 50 percent capacity river water intake pumps which are located at an intake structure near the northwest corner of the pond. The clean water holding pond provides storage and clarification of the river water for cooling tower makeup and other station supplies. As part of the pretreatment facility, the pond capacity is sufficient to accomplish initial sedimentation and removal of the bulk and suspended solids in the river water. As part of the general water management system, the pond receives treated water from the storm water holding pond. A spillway located in the northwestern-most corner of the pond has been provided for overflow to the river.

**TABLE 6.5-1**
**ASSUMED NORTH RIVER WATER ANALYSIS**

| Constituent | | Max. | Avg. | Min. |
|---|---|---|---|---|
| Calcium (Ca) | ppm as $CaCO_3$ | 188 | 143 | 105 |
| Magnesium (Mg) | " | 131 | 118 | 74 |
| Sodium (Na) | " | 50 | 50 | 50 |
| Potasium (K) | " | 5 | 4 | 2 |
| Total Cations | " | 374 | 315 | 231 |
| BiCarbonate ($HCO_3$) | " | 217 | 162 | 77 |
| Carbonate ($CO_3$) | " | | | |
| Sulfate ($SO_4$) | " | 95 | 111 | 128 |
| Chloride (Cl) | " | 34 | 27 | 24 |
| Nitrate ($NO_3$) | " | 27 | 14 | 1.6 |
| Fluoride (F) | " | 0.8 | 0.7 | 0.4 |
| Total Anions | " | 374 | 315 | 231 |
| Total Hardness | " | 319 | 261 | 179 |
| Methylorange (MO) (total alkalinity) | " | 217 | 162 | 77 |
| Silica ($SiO_2$) | " | 9 | 8 | 7 |
| Iron (Fe) total | " | 5.2 | 3.4 | 2.2 |
| Manganese (Mn) | " | 0.17 | 0.15 | 0.13 |
| Color (Pt Units) | | 60 | 40 | 20 |
| Turbidity (JTU) | | 300 | 175 | 50 |
| Total Dissolved Solids | ppm as $CaCO_3$ | 547 | 438 | 319 |
| pH | | 8 | 7.6 | 7.14 |
| Carbon Dioxide ($CO_2$) | ppm as $CO_2$ | 3.4 | 6 | 7.14 |

### 6.5.1 Main Circulating Water System

The main circulating water system consists primarily of a cooling tower and basin, circulating water pumps, main condenser and circulating water pipe. The system is primarily designed to condense the exhaust steam from the steam turbine.

The cooling tower serving both the circulating water system and the auxiliary cooling water system is a four-cell, induced mechanical draft, double cross flow, evaporative (wet) design. The tower is located west of the plant island and orientated parallel to the predominant wind direction. Each cell is 43 feet wide, 85 feet deep and 65 feet high. All cells are in line and mounted at ground level over a common cast-in-place concrete basin. Each cell has a 32-foot diameter propeller fan located in the exhaust stack. The fan is driven through a speed reducer by a 200 HP electric motor.

The tower is sized to reject 850 x $10^6$ Btu/hr by evaporation and convection, based on an ambient dry bulb temperature of 50$^oF$ with a 60 percent relative humidity, which corresponds with a wet bulb temperature of 51.4$^oF$. The heat load is the sum of the circulating water system and auxiliary cooling water system at the ISO ambient conditions. The total water flow is 91,500 gpm.

The tower is basically constructed of precast concrete sides, dividing walls, louvres, and distribution deck. The tower fill is a perforated polyvinyl chloride slating carried by a network of plastic coated wire. Other components are of plastic, steel-reinforced plastic or fiberglass, all of which contributes to a durable and long-lasting tower.

The water is circulated from the cooling tower basin, through the main condenser and back to the flow distribution deck of the cooling tower by two 50 percent capacity, vertical axial-flow, submerged type circulating water pumps of the single stage, mixed-flow impeller design. Each pump is rated at 42,500 gpm at 65 feet TDH while driven by a 900 HP electric motor. The discharge of each pump is equipped with an expansion joint and motor-operated butterfly valve. The valve operation is controlled relative to the starting and stopping of the pump so as to eliminate the need for discharge check valves and to prevent sudden changes in flow.

The pump wet well is separated from the tower basin by removable screens which prevent the entrance of collected debris that have been washed from the air passing through the tower from entering into the circulating water system.

The concentration of dissolved salts in the water is limited by tower water blowdown to the river from the pump wet well.

The 72" circulating water pipe, which loops from the cooling tower to the condenser at the steam turbine generator is a reinforced concrete water pipe, steel cylinder type, AWWA standard C300 series. Bell and spigot type connections are used at the joints.

A separate 16" I.D. reinforced concrete-steel cylinder pressure pipe delivers auxiliary cooling water to the balance of the cooling equipment.

Tower water makeup to replace that lost from the cycle due to evaporation, blowdown, drift, carryover and leakage comes from the clean water holding pond. Water flows by gravity from the pond to the tower basin and the amount required is controlled by basin-water-level flow control valves.

The 3600 gpm of makeup water supplied from the clean water holding pond to the cooling tower basin is acid treated and chlorinated at the cooling tower. The strong acid storage tank and chlorine storage containers are adjacent to a chemical treatment building located south of the cooling tower.

Acid feed equipment is used for the reduction of calcium alkalinity in the cooling tower water. The equipment is identical to that provided for neutralization of storm and waste water except that acid feed is controlled to maintain the pH of the circulating water in the cooling tower within a pH range of 6.9 to 7.5.

Chlorination equipment is provided for shock chlorination of the cooling tower water in order to retard the growth of slime, algae and other forms of aquatic life on cooling tower surfaces and on the cooling water side of the main condenser, auxiliary equipment coolers, pumps and piping. The equipment includes the necessary number of evaporators and chlorinators sized to maintain a chlorine feed rate of four (4) ppm at the design circulating rate for the cooling tower system.

All water required for station makeup is chlorinated, lime softened, clarified and filtered using normal cold process treatment procedures. Coagulation and precipitation of calcium carbonate and entrained solids during treatment causes the entrainment and removal of iron, manganese, and other trace metals and organic matter. The expected composition of the filtered effluent is shown in Table 6.5-2, Water Analysis After Treatment.

**TABLE 6.5-2**
**WATER ANALYSIS AFTER TREATMENT**

| Constituent | | Composition After Lime Softening |
|---|---|---|
| Calcium ($Ca^{++}$) | ppm as $CaCO_3$ | 35 |
| Magnesium ($Mg^{++}$) | " | 118 |
| Sodium ($Na^+$) | " | 50 |
| Potassium ($K^+$) | " | 5 |
| Hydroxide ($OH^-$) | " | trace |
| Carbonate ($CO_3^{--}$) | " | 37 |
| Sulfate ($SO_4^{--}$) | " | 109 |
| Chloride ($Cl^-$) | " | 34 |
| Nitrate ($NO_3^-$) | " | 27 |
| Fluoride ($F^-$) | " | 1 |
| Total Hardness | " | 153 |
| Methylorange (MO) (total alkalinity) | " | 37 |
| Silica ($SiO_2$) | " | 8 |
| Iron (Fe) Total | " | |
| Manganese (Mn) | " | 0.3 |
| Turbidity (JTU) | | 1 |
| Color (Pt Units) | | 0 |
| Carbon Dioxide ($CO_2$) | ppm as $CO_2$ | 0 |
| pH | | 9 - 10.2 |

### 6.5.2 Auxiliary Cooling Water

The auxiliary cooling water system includes three cooling water pumps located outdoors at the north end of the cooling tower basin. The pumps are installed on a deck above the basin wet well. The wet well is separated from the tower basin by a removable screen, which protects the pumps from any foreign material entrapped in the basin, and prevents this material from entering the auxiliary cooling water system. The pumps furnish cooling water to the various coolers in the power block, as well as other miscellaneous heat exchangers throughout the station. The return cooling water is collected at the condenser discharge line and returned in the main circulating water return pipe to the cooling tower.

The three cooling water pumps are each rated at 50 percent capacity. Each pump is a single-stage, vertical turbine type, rated at 3250 gpm at 120' TDH with a 150 HP electric motor.

Two half-size strainers with automatic self-cleaning backwash features are installed adjacent to the pumps in the cooling water supply pipeline to the plant.

Table 6.5-3 lists the station auxiliary cooling water requirements.

**TABLE 6.5-3**
**AUXILIARY COOLING WATER REQUIREMENTS**

| | |
|---|---|
| Steam Turbine Unit | |
| Lube oil cooler | 950 gpm |
| Generator $H_2$ cooler | 1000 gpm |
| Exciter air cooler | 75 gpm |
| Hydraulic fluid cooler | 25 gpm |
| Each Gas Turbine Unit | |
| Lube oil cooler | 750 gpm |
| Generator $H_2$ cooler | 1000 gpm |
| Exciter air cooler | 75 gpm |
| HRSG blowdown tank | 225 gpm |
| HRSG sample cooler | 20 gpm |
| Air compressor aftercooler | 15 gpm |
| Air compressor water jacket | 15 gpm |
| H.P. boiler water circulator | 15 gpm |
| Boiler feed pump | 40 gpm |
| Miscellaneous Cooling Requirements | 100 gpm total |

Since the source of auxiliary cooling water is the cooling tower basin, water treatment for the auxiliary water cooling system is described in Subsection 6.5.1 of this Report.

## 6.6 WASTE HANDLING REMOVAL AND STORAGE

In order to comply with the various regulatory requirements, waste management has become of major significance in power plant design and siting. Provisions are included for collecting, storing and treating all contaminated plant wastes as well as measuring and monitoring the effluents for precise determination of the contaminant levels. Environmental considerations are also included in determining on and off-site disposal of the concentrated wastes.

Liquid wastes from the water treatment equipment, station equipment, floor drains, boiler blowdown, storm water, and fuel treatment effluent are collected and stored in the Storm Water and Wastes Holding Pond. Those liquid wastes which may contain oil are routed through a primary oil/water separator prior to discharge to the Storm Water and Wastes Holding Pond. The stored wastes are then treated in a clarifier and returned to the Clean Water Holding Pond for reuse as makeup to the cooling tower and other station services.

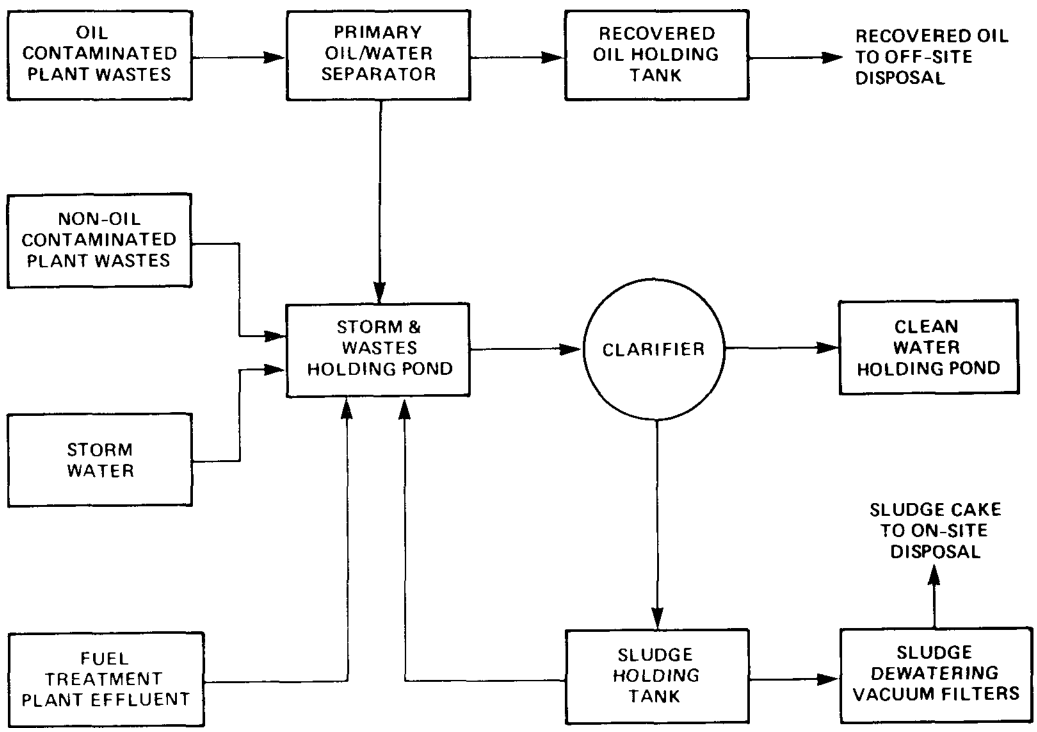
The only solid wastes to be considered in the coal-derived liquid fuel plant are those suspended solids which collect on the bottom of the Clean Water Holding Pond and the Storm Water and Wastes Holding Pond, and sludge cake from the vacuum filters which dewater the underflow from the clarifiers. These deposits are periodically removed as required for on-site disposal in fill areas.

### 6.6.1 Solid Wastes

Unlike the combined cycle station with integrated LBTU gasifier, the combined cycle gas turbine system using a coal-derived liquid fuel produces no significant amount of solid wastes. Although the Clean Water Holding Pond and the Storm Water and Wastes Collecting Pond are designed to operate efficiently for many years, it may become necessary from time to time to remove solids and silt deposits which will collect at the bottom of these ponds. These deposits will be removed by dredging and disposed of on-site in fill areas. A sludge cake off the vacuum filters which dewater the underflow from the two plant clarifiers will also be removed periodically and dumped into on-site spoil areas.

### 6.6.2 Liquid Wastes

Liquid wastes result from the pretreatment and demineralization waste effluents of station feedwater makeup, water collected from station roof and floor drains, equipment drains, boiler blowoff and blowdown, storm water and fuel treatment plant effluent. The various liquid wastes are collected and stored in the Storm Water and Wastes Holding Pond, treated in the clarifier and discharged to the Clean Water Holding Pond for reuse as station makeup and service water. Figure 6.6-1 is a Block Diagram of the liquid wastes system.




**LIQUID WASTE BLOCK DIAGRAM**
**Figure 6.6-1**

Facilities for the continuous treatment of the liquid wastes discharged to the Clean Water Holding Pond include a clarifier, water/oil separator, the necessary pumping lift stations, chemical feed equipment, chemical storage, flow controls, monitoring systems and piping systems.

Equipment and floor drains that may possibly contain oil are collected in a below-grade sump and pumped to a primary oil/water separator prior to discharge to the Storm Water and Wastes Holding Pond. The retained oil from the separator is transferred to a 2000-gallon holding tank from which it is periodically pumped into a tank truck for off-site disposal.

The Storm Water and Wastes Holding Pond is designed for a ten-year, 24-hour storm water condition and is provided with an impervious vinyl sheet liner to prevent groundwater contamination by infiltration of heavy metals and organics.

Water from the holding pond is pumped to the clarifier by two 100 percent capacity, self-priming pumps located in the chemical treatment building adjacent to the cooling tower. Chemical treatment in the clarifier produces water which meets disposal requirements. The precipitated solids in the clarifier are collected in a sludge holding tank. The liquid sludge is then pumped through rotary-belt vacuum filters to permit dewatering and on-site truck disposal of the sludge cake. The effluent from the filters is returned to the Storm Water and Wastes Holding Pond.

# SECTION 7
# SITE PLAN

The Middletown site selected for the combined cycle station using a coal-derived liquid fuel is situated on a flood plain, 25 miles south of a major population center. The characteristics of the site are ideal, with access to major and secondary roadways, a major railroad and river water supply. The topography is gently rolling with no major topographical features.

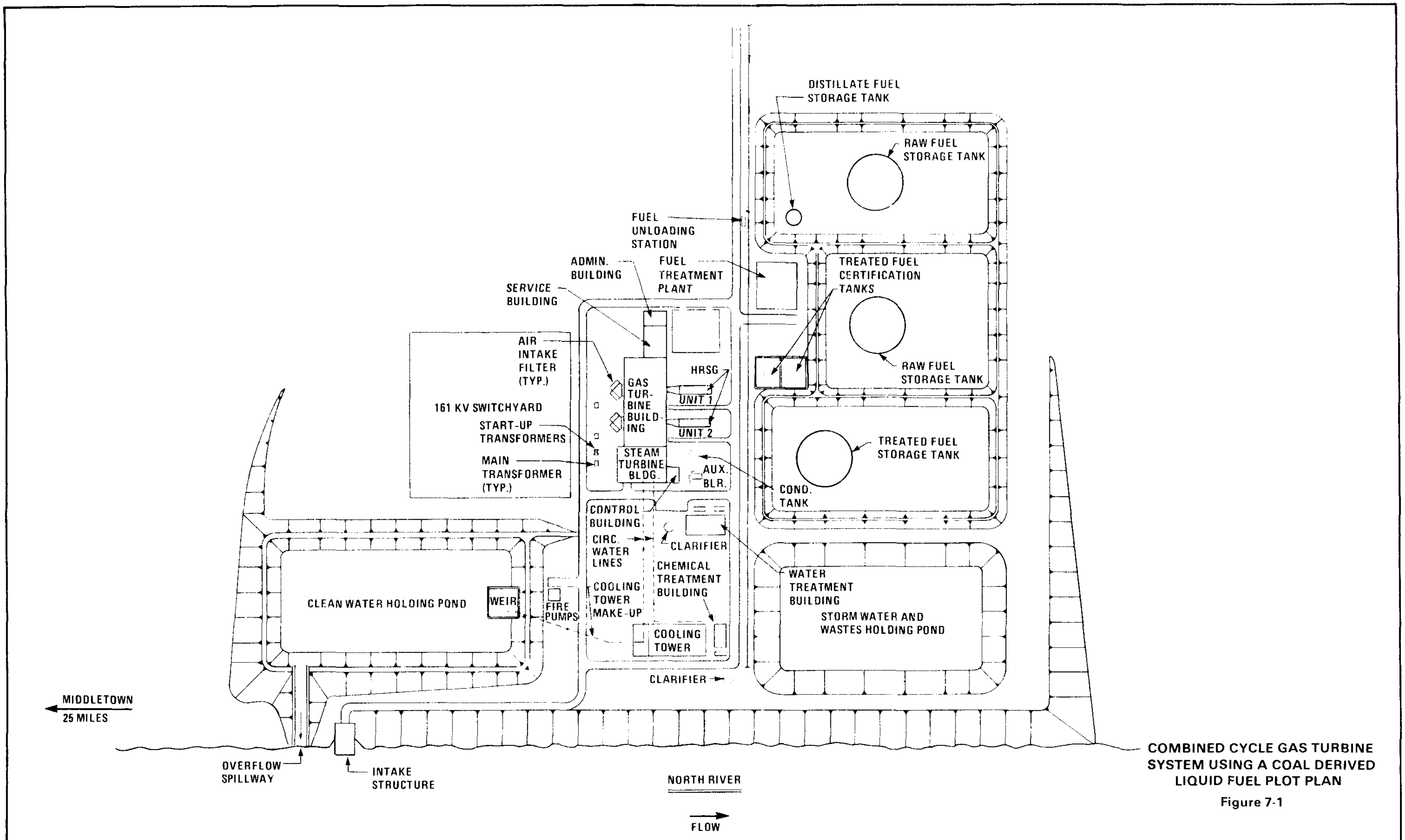
The actual land requirement for the station exclusive of the access track right-of-way is 94 acres. The Plot Plan in Figure 7-1 shows the major station buildings, switchyard, fuel storage and treatment areas, cooling tower and the water holding ponds. A single railroad track and roadway enter the station from the east side. Grade elevation for the station area is approximately twenty (20) feet above mean river level with the necessary diking and grading as required and indicated on the Plot Plan. Details of the Plot Plan are described in Subsection 7.2 of this report.

The plant island general arrangement as shown on Figure 7-2 and further described in Subsection 7.3 of this report, was developed by taking into consideration the optimization of building sizes; minimizing lengths of main steam, hot and cold reheat steam and condensate piping; locating the steam turbine-generator and condenser relative to the remainder of the cooling water system; and the traditional close coupling of the heat recovery steam generator to the gas turbine exhaust. Other considerations included a clear direct path from the electric generators to the switchyard, locating the switchyard on the north side in the direction of the major user of the electricity and developing a compact arrangement for the oil storage and treatment facilities clear of the major station structures.

The elevation of the plant, Figure 7-3, corresponds to the plant island arrangement and shows a view of the plant looking west from a section line located between the two gas turbines. The view includes all major equipment, the bi-level station building and the various floor, roof and stack elevations. The elevation is further described in Subsection 7.4 of this report.

## 7.1 SITE AND SITE DEVELOPMENT

The Middletown site as described in WASH 1230 Section 2, modified to reflect fossil power plant siting, is being used for the combined cycle gas turbine system using a




**COMBINED CYCLE GAS TURBINE SYSTEM USING A COAL DERIVED LIQUID FUEL PLOT PLAN**

**Figure 7-1**

coal-derived liquid fuel. The layout and general arrangement of the items covered in this section are shown on the Plot Plan, Figure 7-1.

### 7.1.1 General Site Description

The Middletown site is located on the east bank of the North River, 25 miles south of Middletown. The site is a flood plain approximately 2600 feet wide, running easterly from the river to hills whose top elevations vary from 150 to 200 feet above mean river level. Beyond this area, the topography is gently rolling with no major topographical features. The plant site extends from river level to elevations of fifty feet above river level.

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

Access to the site is provided by five miles of existing secondary roads connecting to a state highway. These secondary roads need no improvement. Railroad access is accomplished by constructing a spur to a major railroad located near the site. The assumed length of the railroad spur is five miles. All plant shipments for both construction and operation are assumed to be overland.

Power and water for construction is available at the southwest corner of the site.

The site for the plant is 2400 feet long and 1700 feet wide requiring 94 acres.

The plant island area, including all primary structures and the switchyard, is located approximately 650 feet from the east bank of the river and approximately in the center of the site in a north-south direction. The plant island area is to be leveled and filled to an elevation 20'-0" above mean river level. Buildings within the plant island are discussed in Subsection 7.3 of this report.

From weather bureau records: site surface winds are predominately southwesterly at 4-10 knots during warm months, and westerly 6-13 knots during cold months. The hills tend to channel winds to a north-south direction. A maximum instantaneous wind velocity of 100 mph has been recorded at the site. No significant damage from severe meteorological phenomena in the last fifty years has been recorded.

### 7.1.2 Detailed Site Description

#### 7.1.2.1 RAILROAD FACILITIES

The five mile spur track runs along the south side of the plant, between the heat recovery recovery steam generators and the fuel treatment and storage areas, extending westerly to the cooling tower. This track facilitates installation, service, and maintenance of plant equipment and can also be used for the delivery of distillate fuel oil.

In addition to the site land requirement of 94 acres an additional 91 acres is required for the five miles of spur track from the main line to the site. A 150 foot wide right-of-way is assumed for this access track.

#### 7.1.2.2 DRAINAGE AND WASTE DISPOSAL

Drainage south of the plant area is accomplished with ditches sloped to, and emptying into a 625 foot x 375 foot storm water and wastes holding pond at the southwest corner of the site. Storm drainage from the switchyard area is collected in area drains and transferred to the 625 foot x 325 foot clean water holding pond. In selection of the waste water management system for the fuel treatment plant area, primary consideration was given to the reuse of the fuel treatment plant effluent. Fuel treatment area waste disposal is discussed in detail in Subsection 6.6 (Waste Handling, Storage and Removal) of this report.

In the plant area, catch basins and storm sewers are located as required with ultimate discharge into the storm water and wastes holding pond.

Inside the station building water collected from equipment and floor drains is treated by oil separators, then pumped from a station sump to the storm water and wastes holding pond.

North of the storm water and wastes holding pond is a clarifier. Pumps, located in the chemical treatment building, take suction from the pond and discharge to the clarifier. Following treatment in the clarifier, the water is pumped to the clean water holding pond. This treatment process is also discussed in detail in Subsection 6.6 of this report.

Sewage disposal facilities consist of a packaged primary and secondary treatment system with effluent chlorination. The effluent is discharged into the clean water holding pond.

#### 7.1.2.3 WATER SUPPLIES

Makeup to the clean water holding pond located at the northwest corner of the site, is supplied by river water through an intake structure and by the treated water from the storm water and wastes treatment clarifier. The pond is surrounded and protected by earthen dikes and has an emergency spillway into the river on the west side and an overflow weir into a pump well on the south side.

Water for the fire protection loop, and the raw water treatment plant, is supplied by pumps taking suction from the clean water holding pond at the overflow weir.

Makeup water for the cooling tower basin is likewise supplied from the clean water holding pond. The evaporative, mechanical draft cooling tower is situated at the west edge of the site on the south side of the clean water holding pond. Details of the cooling tower are discussed in Subsection 6.5 (Cooling Water System) of this report.

Potable water service is supplied from wells or the river. Potable water is chlorinated and treated to the extent necessary to meet local plumbing codes.

#### 7.1.2.4 LANDSCAPING AND ROADWAYS

The plant island area surfacing at finished grade inside of the plant loop road consists of a six (6) inch flexible base course.

The plant entrance road extends westward past the south end of the heat recovery steam generators to a road at the chemical treatment building running north to the intake structure. A road also completely loops the plant island area and has an extension south to the fuel treatment area. Parking areas are provided at the administration building, and control building. All roadways and parking areas are constructed of asphalt on a flexible base material.

A chain-link type fence topped with three strands of barbed wire is used around the station perimeter and is grounded in certain areas.

Select areas are seeded with grass.

#### 7.1.2.5 SWITCHYARD

A 400 foot x 400 foot switchyard is located east of the clean water holding pond, adjacent to and north of the transformer area.

#### 7.1.2.6 FUEL TREATMENT AND STORAGE AREA

The fuel storage area consists of two raw fuel storage tanks and one treated fuel storage tank, each tank is 140 feet in diameter and forty (40) feet high. The tank perimeters are supported on concrete ring beam foundations with the remaining portion of the tanks resting on compacted sand and gravel. The distillate, raw and treated fuel storage areas are enclosed and protected by individual 6 foot high earthen dikes to prevent possible spillage from spreading to other areas.

The fuel treatment area consists of a fuel treatment plant and two treated fuel certification tanks. These tanks are enclosed by concrete walls. Details of the waste disposal from this area is discussed in Subsection 6.6 (Waste Handling, Storage and Removal) of this report.

#### 7.1.2.7 BULK GAS STORAGE AREA

To the west of the plant island, near the water treatment building, is the bulk gas storage area. The equipment in this area is supported on either a reinforced concrete slab or pedestal supported as may be required.

#### 7.1.2.8 SOIL AND GEOLOGICAL CHARACTERISTICS

Soil profiles show alluvial soil and rock fill to a depth of eight (8) feet; Brassfield limestone to a depth of thirty (30) feet; blue weathered shale and fossilferous Richmond Limestone to a depth of fifty (50) feet. Allowable soil bearing is 6,000 psf and rock bearings are 18,000 psf and 15,000 psf for Brassfield and Richmond strata, respectively. No underground cavities exist in the limestone.

#### 7.1.2.9 SEISMOLOGY

The site lies within a zone 1 earthquake design area (from Uniform Building Code).

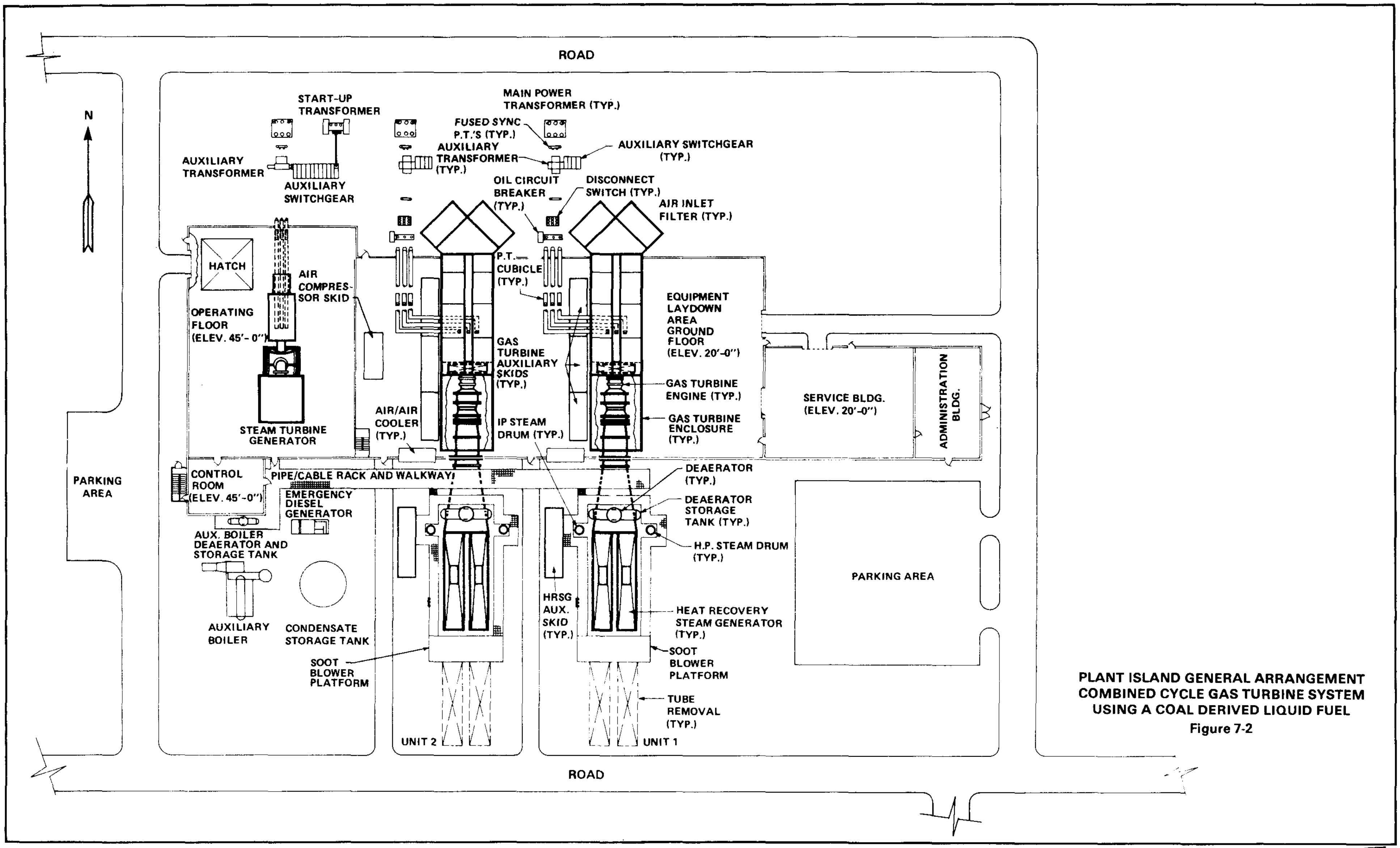
## 7.2 PLOT PLAN

The plot plan for the combined cycle plant using a coal-derived liquid fuel, Figure 7-1, shows the plant island, switchyard, fuel treatment and storage areas, Storm Water and Wastes Holding Pond, cooling tower, water and chemical treatment buildings, clarifiers, Clean Water Holding Pond, major dikes, and the roadways and railroad track which serve the site.

The plant island, Figure 7-2, is located approximately in the center of the site and is described in Subsection 7.3 of this report. The transformers and switchyard are located to the north of the plant island, the side nearest the major population and load center.

The fuel storage and treatment areas are located to the south of the plant island, clear of all high voltage transmission lines and their supporting structures, and the other major plant island structures. The fuel storage and treatment areas are described in Subsections 6.1, 6.2, and 6.3 of this report.

The Clean Water Holding Pond is located parallel to the North River, west of the switchyard, and north of the cooling tower. The pond capacity maintains a limited storage of cooling tower and other station makeup water and is of sufficient size to




**PLANT ISLAND GENERAL ARRANGEMENT COMBINED CYCLE GAS TURBINE SYSTEM USING A COAL DERIVED LIQUID FUEL**
**Figure 7-2**

accomplish initial sedimentation and removal of river water suspended solids. A spillway is provided at the northern-most point of the pond for overflow to the river. South of the spillway and adjacent to the river is an intake structure containing three, 50% river water supply pumps which discharge into the Clean Water Holding Pond. Two fire pumps, one motor driven and one diesel-engine driven are located on the south side of the Clean Water Holding Pond and provide for the fire protection of the station.

The multiple cell, mechanical draft cooling tower is located west of the plant island and south of the Clean Water Holding Pond, such that the cooling water supply and return lines for the condenser and other auxiliary cooling equipment lie in a clear direct route from the tower to the plant and back. The cooling tower cells are arranged in a north-south direction parallel to the predominant wind direction. A further description of the cooling tower is included in Subsection 6.5.1 of this report.

The chemical treatment building, equipment and clarifier, all located south of the cooling tower and north of the Storm Water and Wastes Holding Pond, are used for cooling tower and storm water treatment. Water supplied from the Clean Water Holding Pond to the cooling tower for makeup is chlorinated and acid treated at the cooling tower basin. The water treatment building, equipment and clarifier located adjacent to and west of the plant island treats the water required for feedwater makeup. The clarifier is installed outdoors, adjacent to the water treatment building housing the demineralizer and laboratory. The equipment is also in close proximity to the condensate storage tank. A detailed description of the water treatment system for station makeup is included in Subsections 6.4 and 6.5 of this report.

A Storm Water and Wastes Holding Pond is located south of the cooling tower and west of the fuel storage area for the purpose of collecting station storm water, contaminated plant wastes and effluent from the fuel treatment plant. The water is treated in the clarifier located adjacent to the chemical treatment building and discharged to the Clean Water Holding Pond to supplement the station makeup water requirements.

Railroad facilities are provided which enter at the east edge of the site for the delivery of No. 2 distillate fuel oil and major equipment during construction. Not shown, is five miles of access track required to connect the track at the east boundary of the site to the main line.

## 7.3 PLANT ISLAND ARRANGEMENT

The plant island arrangement for the combined cycle gas turbine system using coal-derived liquid fuel is shown on Figure 7-1. The arrangement drawing shows the steam turbine building, gas turbine building, heat recovery steam generators, main power transformers with their associated auxiliary switchgear and circuit breakers, and the control, service and administration buildings.

### 7.3.1 Steam Turbine Building

The steam turbine building houses the steam turbine-generator unit, condenser, and the auxiliaries required for the unit. The building is located on the west side of the plant island to minimize the piping lengths between the cooling tower and condenser. The building is sized and equipment arranged to provide adequate space for removal of the generator rotor along the unit axis and for laydown of parts during maintenance periods. A partial mezzanine floor is provided below the operating floor for locating auxiliary mechanical and electrical equipment, and for access to the control building. Access from the steam turbine building to the control building is also provided at the operating and ground floor levels. Other auxiliary equipment, such as condensate pumps, are located on the ground floor level.

### 7.3.2 Gas Turbine Building

The gas turbine building houses the two gas turbine-generator units and their respective auxiliary skids. The units are located on the ground floor on 80'-0" centers with their associated auxiliary skids located adjacent to the respective units. The turbine air-to-air cooler is located in the south wall adjacent to each unit. A packaged air compressor skid, provided for plant control and service air, is located in the west end of the building. Equipment laydown area is provided at the east end of the building for the gas turbine unit components during maintenance periods.

### 7.3.3 Heat Recovery Steam Generators

The heat recovery steam generators (HRSG), one for each gas turbine unit, are located outside the south wall of the gas turbine building, each close coupled with ducting to its respective gas turbine. Vertical steam drums and deaerator equipment are supported by the structural steel members supporting the HRSG. An auxiliary equipment skid adjacent to each HRSG includes the chemical feed system, motor control center, etc.

### 7.3.4 Transformers And Switchgear

Three main power transformers and their associated switchgear and circuit breaker equipment are located on the north side of the station buildings. A start-up transformer is also located in this area to supply the auxiliary equipment for start-up and shut-down load requirements. The equipment is in a direct line between the generators and the switchyard.

### 7.3.5 Miscellaneous Facilities

The control building is located adjacent to the steam turbine building, with the control room at the operating floor level and the cable spreading and electronics rooms below.

Access, by a stairtower at the west end of the building, is provided between the various floors of the control building and the steam turbine building and also to the HRSG's via an elevated walkway on the south side of the gas turbine building. Outside the control building are the common plant facilities; the auxiliary boiler, emergency diesel-driven generator, auxiliary boiler feed pump, condensate storage tank and auxiliary boiler deaerator with storage tank.

### 7.3.6 The Administration And Service Buildings

The administration and service buildings are located together at the east end of the plant island, at the entrance side to the station, with parking facilities adjacent to the buildings. No attempt has been made to detail these buildings except to identify functions in order to approximate space requirements based on current practices for coal fired steam power stations. The service building is a single story structure containing shop, maintenance and storage areas. The administration building is a multi-story building housing offices, locker room and reception area.

## 7.4 PLANT ISLAND ELEVATION

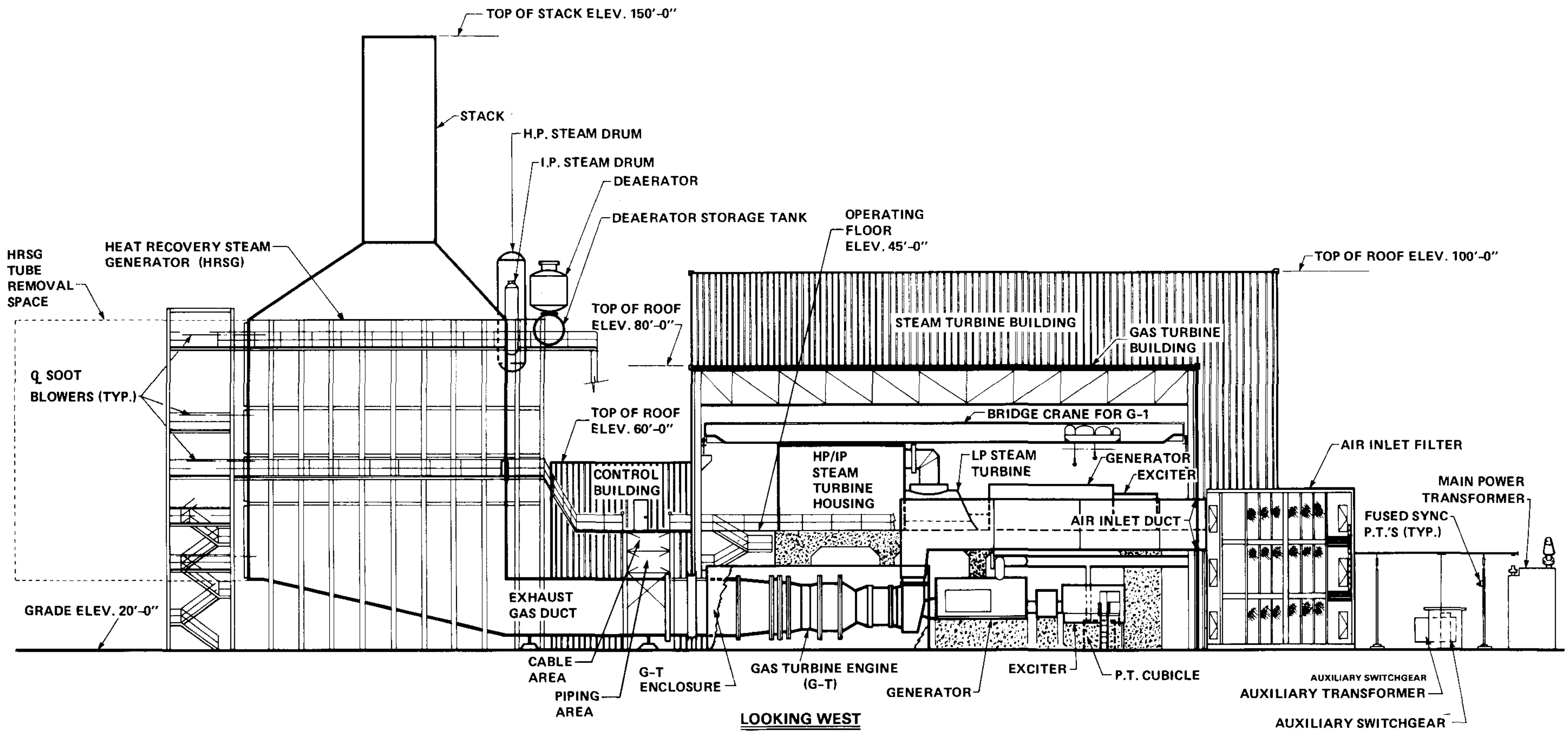
An elevation view of the combined cycle gas turbine system using coal-derived liquid fuel is shown on Figure 7-3. In relation to the Plant Island General Arrangement, the view is taken between the gas turbine-generator units looking west. The elevation shows the major equipment, including a gas turbine-generator unit, heat recovery steam generator (HRSG), transformers, and steam turbine-generator unit, as well as the various building elevations.

The gas turbine-generator units are located on the ground floor, elevation 20'-0". An inlet air filter structure is located at the north side of the building to supply clean air to the gas turbine. The gas turbine exhausts to the close coupled heat recovery steam generator through a steel duct supported to allow for thermal expansion. Each HRSG is provided with a rectangular steel stack to elevation 150'-0" to carry the HRSG exhaust gases above the station buildings. The stack height was estimated since air quality and stack optimization studies were not conducted during Phase I of the study.

Due to the fuel characteristics, it has been assumed that soot blowers are required in the HRSG for maintaining optimum output and efficiency. They are the retractable type with the blowing medium, steam, taken from the cold reheat steam line. The necessary soot blower access platform structure has been included on the south end of each HRSG.

A combination walkway-cable tray-pipe rack structure is provided on the south side of the steam turbine and gas turbine buildings. The structure provides support for the major steam and feedwater piping systems between the steam turbine and the HRSGs, and for the cable trays from the control building to the various equipment. A walkway is included as the top level of the structure for access between the control room, the steam turbine building operating floor, the auxiliary boiler deaerator and the two HRSGs.

In the elevation, a portion of the pedestal mounted steam turbine-generator unit is shown on the operating floor at elevation 45'-0". There is no wall where the gas turbine and steam turbine buildings meet, but additional structural steel is required to support the overhead crane in the steam turbine building since it runs perpendicular to the gas turbine building crane which is shown. Not shown are the steam turbine building crane and additional structural steel.




**PLANT ISLAND ELEVATION - COMBINED CYCLE GAS TURBINE SYSTEM USING A COAL DERIVED LIQUID FUEL**
**Figure 7-3**

# SECTION 8

# ELECTRICAL SYSTEM

The plant electrical system for the reference design is defined on Figure 8-1 and discussed in this section. The system is representative of current Westinghouse PACE practice and conventional power plant design.

## 8.1 DESIGN CRITERIA

### 8.1.1 General

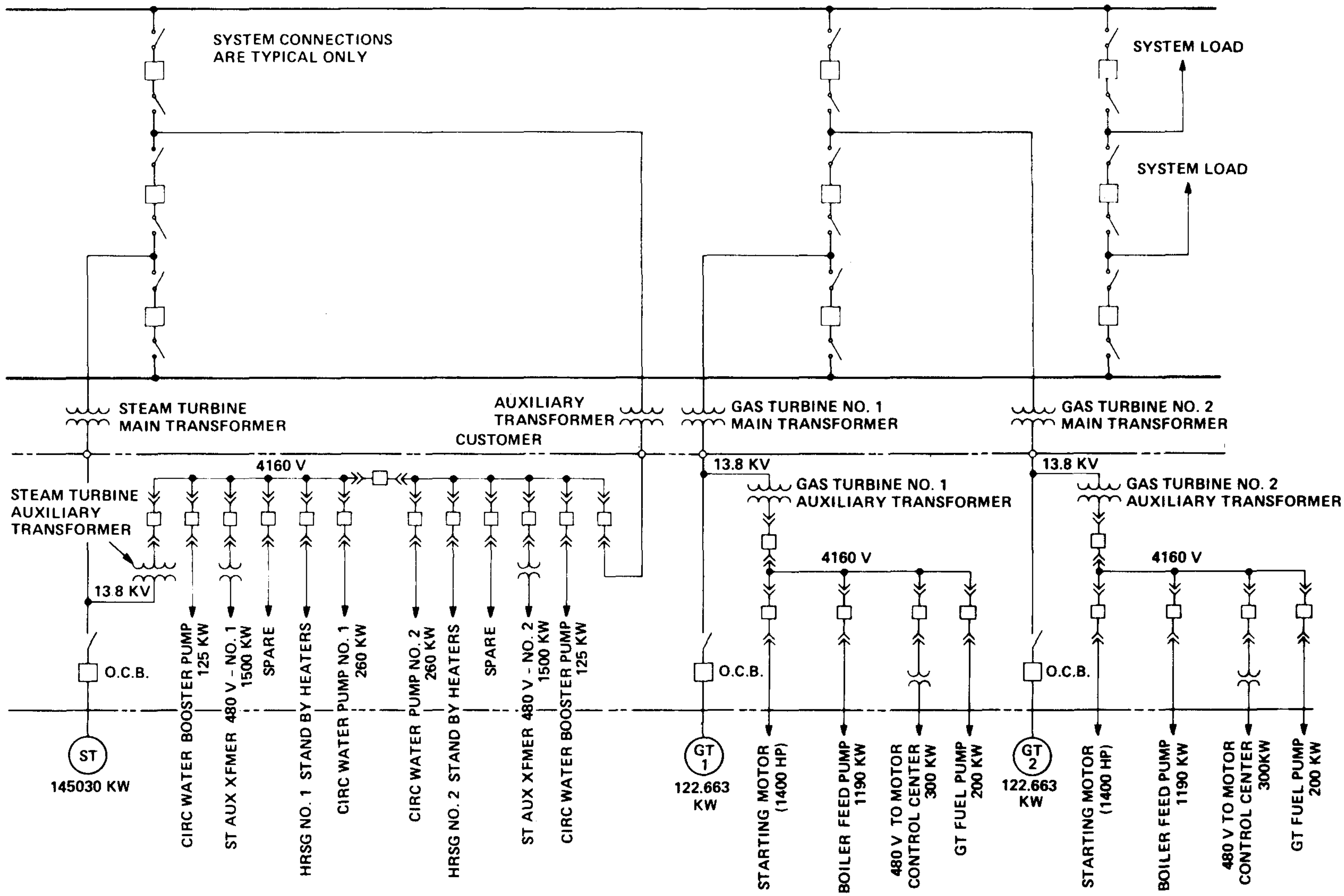
The electric power system for the station is designed to be electrically self-sufficient and to provide adequate, redundant and reliable power sources for all electrical equipment during start-up, normal operation, shut-down and emergency conditions.

### 8.1.2 Generators And Switchgear

The station will have three generators, two 123 MW, 13.8 kV, 60 HZ gas turbine-generators, and one 145 MW, 13.8 kV, 60 HZ steam turbine-generator. The output of these generators, less the station auxiliary load, will be stepped up to the station 161 kV switchyard by their associated main transformers. The station will have a start-up transformer fed from the switchyard to provide power for station start-up, shut-down and post shut-down requirements.

### 8.1.3 Auxiliary Power Systems

The station auxiliary electrical systems will consist of auxiliary transformers, one associated with each generating unit; 4160 V and 480 V A-C distribution systems; a 120 V A-C vital instrumentation and control system; a 125 V D-C system; a 480 V emergency diesel-driven generator unit; and the associated switchgear, distribution panels, auxiliary equipment and motors. The station does not have black-out start capability. An emergency diesel-driven generator is provided as the on-site stand-by power source to supply station essential loads upon loss of all normal and reserve power sources. The essential loads consist of steam turbine-generator shut-down loads, essential A-C lighting load, vital A-C system, battery chargers and other emergency loads as required. The station 120 V vital A-C system supplies uninterruptable power for the station instrumentation and other vital equipment.




**COAL DERIVED LIQUID FUEL PLANT ELECTRICAL SINGLE LINE DIAGRAM**
**Figure 8-1**

Each turbine unit has its own associated 125 V D-C batteries and battery chargers included in the auxiliary package.

### 8.1.4 Control Panels And Electronic Equipment Panels

Central and local control boards and panels, and central computer and electronic equipment panels necessary for the control of all systems in the station are provided. The central panels are located in Control and Electronics Equipment Rooms and required for a safe and reliable operation of the station. Local control stations are located throughout the station.

### 8.1.5 Motors

All AC motors are the squirrel-cage induction type designed for full voltage starting with the lowest locked rotor current consistent with good performance and design. Motors larger than 250 HP are rated 4000 V, 3 phase, 60 HZ. Motors 200 HP and smaller to 1/2 HP and all motor operated valve actuator motors are rated 460 V, 3 phase, 60 HZ. Fire pump motors are rated 460 V, 3 phase, 60 HZ. Fractional HP motors below 1/2 HP are rated at 115 V, single phase, 60 HZ. All motors are suitable for operation at the rated load with a combined variation of 10% above or below the rated voltage and frequency provided that the frequency variation does not exceed 5%. All AC motors except the gas turbine starting motors, are able to accelerate their loads to full speed at 80% of the rated voltage at the motor terminals. The gas turbine starting motors are capable of accelerating their loads to full speed at 90% of the rated voltage at the motor terminals.

### 8.1.6 Miscellaneous Electrical System Equipment

A station grounding grid is buried beneath the grade surface. The conductors are of sufficient size to carry the maximum ground fault current and to limit step and touch potentials to safe values under any fault condition. A separate instrumentation grounding is provided connecting to the ground grid at one point only.

Communications from the station is accomplished by a limited number of outside lines. Internal communications primarily consist of a private automatic system and public address system. Telephones and loud-speakers are located at selected points throughout the station. A cathodic protection system is provided for corrosion control as necessary.

Normal, emergency, and essential lighting is provided for the station building and selected outdoor areas. Normal and essential lighting panels are energized continuously from station motor control centers through individual local 480-120/208 V four-wire dry type distribution transformers. The distribution transformer energized

120/208 V local lighting panels are dispersed throughout the station and associated outlying areas. Emergency lighting is supplied for illuminating vital areas and egresses.

Freeze protection transformers and panels with circuit monitoring provisions are furnished to provide protection for all equipment and piping subject to freezing.

### 8.1.7 Lighting

Normal, emergency and essential lighting are provided for the station building and selected outdoor areas. An essential lighting panel is energized continuously from the normal plant auxiliary system through individual 480/120/208 volt four-wire dry type lighting transformers energized from the 480 V essential MCC. The essential lighting panels, dispersed throughout the plant and outlying areas as necessary, are sectionalized to handle the essential A-C lighting load and portions of the D-C energized lighting load.

The remainder of the A-C lighting (normal lighting) is energized continuously from the unit auxiliary system through individual 480-120/208 volt four-wire dry type transformers mounted locally and energized from nearby motor control centers. Local lighting transformers and lighting panels are conveniently located throughout the station building and outlying areas.

Emergency D-C lighting for vital areas and egress lighting is fed from emergency sections of the various lighting panels. The D-C lighting is energized automatically upon loss of normal A-C lighting.

Outdoor lighting is controlled by photoelectric cells. A selector switch is provided to facilitate manual override or automatic operation of the outdoor lighting.

Control room lighting is so designed to provide glare-free lighting on the control board and includes ceiling fixtures and emergency A-C lighting.

The design illumination levels are based on levels recommended by the IES. Lighting fixtures are of the industrial fluorescent type for indoor areas, except for high bay installations where mercury vapor or high-pressure sodium types are used. For other areas, industrial incandescent fixtures, mercury vapor or high-pressure sodium fixtures are used. Outdoor illuminated areas include the intake structure, fuel unloading area, oil storage area, parking lots and transformer bays.

## 8.2 ELECTRICAL ONE-LINE HV SYSTEMS

### 8.2.1 Generators

The steam turbine-generator is pedestal mounted and located on the operating floor at elevation 25 ft. The two gas turbine-generators are located on the ground floor of the building. The units are arranged so as to provide adequate space for operation, inspection and laydown of equipment during overhauls, as shown on the Plant Island General Arrangement, Figure 7-2.

Each turbine-generator-exciter is factory assembled to check critical alignments, then disassembled to the level required by shipping regulations. Each unit consists of a hydrogen-cooled generator with water coolers and a suitably rated, direct connected, air-cooled, brushless exciter with permanent magnet generator. The hydrogen-cooled generator assemblies include the stator core and winding, rotor and winding, bearings with vibration detectors, hydrogen cooling system, current transformers, neutral grounding transformer and resistor, temperature detector and the three main leads of the generator. The gas turbine-generator leads are located at the top of the unit and the steam turbine-generator leads exit from the bottom.

The brushless exciter assembly includes a permanent magnet generator with a permanent magnet field and armature, an A-C exciter with rotating armature with a stationary field winding and regulator, a rotating rectifier with silicon diodes, bearing with vibration meters, temperature detectors, current transformer, and internally connected leads.

The hydrogen auxiliary control enclosure is mounted on the side of the generator, making it accessible for maintenance and inspection purposes.

### 8.2.2 Main, Auxiliary And Startup Transformers

The main, auxiliary and start-up transformers are located outdoors physically separated from each other as shown on the Plot Plan, Figure 7-1.

The transformers are of sealed construction with completely welded tanks and covers. The main and start-up transformer high voltage bushings are cover-mounted with terminals to accommodate overhead 161 Kv conductors from the switchyard. These units are also provided with three station type lighting arrestors mounted adjacent to the HV bushings. Each transformer is provided with a no-load tap changer, sudden pressure relay, temperature and oil level gauges, indicators and detectors, auxiliary cooling power equipment and accessory equipment for control, monitoring and protection of the unit.

Fire walls are to be installed between transformers and the units are protected by automatic water spray systems to extinguish oil fires quickly and prevent spread of fire.

## 8.3 ELECTRICAL ONE-LINE 5 KV SYSTEM

### 8.3.1 Switchgear 4160 Volts

The 4160 V switchgear are outdoor, metal-clad units rated 4160 volt, with 250 MVA interrupting capacity, horizontal drawout air circuit breakers. Each switchgear assembly consists of main incoming breaker unit, auxiliary units, feeder breaker units, bus, instrument transformers, relays, instruments, meters and control devices. These outdoor units incorporate features of weatherproofing, ventilation, heating and breaker transport truck.

### 8.3.2 480 V Auxiliary System Equipment

The distribution transformers associated with the station 480 V power centers and motor control centers are indoor dry type. The transformer high voltage connection is suitable for copper cables entering from above or below with required compression type terminal lugs. A low voltage terminal compartment is provided for connection to the 480 V power center switchgear or motor control center buses. Transformers have Class H insulation for 150 C rise above 40C ambient temperature. Four 2-1/2% full capacity no-load taps are provided on each unit. The 480 V power center switchgear is indoor, metal-enclosed with drawout type air circuit breakers individually housed in front compartments with rear compartments for buses and power cable connections. Power and control cables are into the switchgear through the bottom or top as required. Solid state trip devices are provided for each circuit breaker to achieve selective system coordination. All required instrument transformers, control devices, meters and relays are provided in the switchgear. The 480 V motor control centers are indoor rated 480 V and braced for fault conditions of 22,000 amperes rms symmetrical. The motor control centers include combination starters, breakers and other accessories and are completely factory assembled and tested. Separate compartments are provided for each combination starter, circuit breaker, vertical and horizontal buses. Provisions for power and control cables to enter from top or bottom are available.

The motor control centers for the gas turbine-generators and steam turbine-generator auxiliary equipment are included in the auxiliary package located adjacent to the corresponding unit. Other motor control centers are to be located throughout the plant in areas of electrical load concentration.

A motor control center is provided to supply power to the station equipment considered vital to safety of personnel and equipment during and after shutdown or during emergencies. This MCC is normally supplied from a 4160/480 V transformer, but upon loss of normal on-site and off-site power, it is supplied from the station emergency diesel driven generator. The loads normally connected to this MCC are essential A-C lighting, vital A-C system, battery chargers, turbine-generator shutdown loads as required and other emergency loads as necessary.

### 8.3.3 Generator Auxiliary Package

Each gas turbine-generator and steam turbine-generator is provided with an electrical auxiliary package, pre-packaged for shipment, and located in the station building adjacent to the generator. The gas turbine-generator package contains the generator voltage regulator, protective relay panel, A-C and D-C motor control centers, battery charger, battery and hydrogen monitor panel. The steam turbine generator auxiliary package contains equipment items which are functionally equivalent to those in the gas turbine-generator auxiliary packages.

### 8.3.4 Motors

Unless specifically noted, motors have Class B insulation and are induction type, Design B.

Indoor motors are of drip-proof construction. Motors located outdoors are of weather protected Type I construction with filters or are totally enclosed, fan cooled. 4000 volt motors and all 460 volt motors 25 HP and larger, are furnished with space heaters that are automatically energized when the motor is idle.

### 8.3.5 125 V D-C System

In addition to the 125 V D-C batteries and battery charger included in the gas turbine auxiliary packages, the station is provided with a common 125 V D-C system with associated batteries, battery chargers and distribution panels for supplying the station common D-C requirements. The 125 V D-C system provides continuous and reliable 125 V D-C power source for control, monitoring, instrumentation and D-C motor loads required for normal operation and orderly shut down of the station.

# SECTION 9
# WATER/STEAM-COOLED SYSTEM

## 9.1 SYSTEM DESCRIPTION

The combined cycle power plant operating on a coal-derived liquid fuel which utilizes a gas turbine whose hot components are cooled with water, steam and air rather than just cooling air, contains the same basic components as the air-cooled turbine combined cycle. There are, however, some additional auxiliaries that will be discussed that influence the cycle configuration to a rather large degree.

The cooling of the gas turbine hot section components involves the use of water, steam and air. Water is used to cool the first and second stator vane assemblies; steam is used to cool the first two rotating blade rows; and air is the coolant for the remaining vanes, the cooled rotor blades, some of the blade roots, and other hot end parts. The water quality required for the stator cooling circuit is a most critical item and parallels that of a nuclear plant. For this reason, the turbine cooling water scheme is a separate, closed system operating at about 1500 psig. Water temperature in and out of the stators is $350^{o}$F and $450^{o}$F, respectively. The cooling steam, (conditions are 220 psia and $480^{o}$F) is extracted from the intermediate pressure steam turbine. Appropriate steam temperature is achieved by attemperating water, bled from the IP drum. The cooling steam exits from the rotating blades into the gas stream and therefore must be replaced in the system through the water makeup circuit. The cooling air is extracted from the compressor, cooled in an external heat exchanger from about $725^{o}$F to $500^{o}$F, and returned to the turbine hot section.

Although the basic components for the water/steam-cooled, liquid fueled, combined cycle are similar to that of the air-cooled configuration, there are some notable differences that require amplification. The amount of heat that must be dissipated from the gas turbine cooling water is sizable and will be discussed further in a later section. The point to be made here is that the heat rejection from the cooling water is used to aid in feedwater heating and deaeration. Combining this energy with the energy from the HRSG low pressure coil creates an excess which results in an appreciable amount of low pressure steam available for induction into the low pressure steam turbine. Also, since steam extraction from the intermediate section is required for gas turbine cooling, the steam turbine basic design will differ from that of the air-cooled cycle. (There is neither IP extraction nor LP induction in the air-cooled cycle.) See Figure 9.4-1.

The reboiler used for a separate steam circuit for fuel heating and heat tracing is very similar to that used in the air-cooled cycle. The HRSG, although containing the same basic elements as that of the air-cooled cycle, will have different gas flow and inlet temperature. Therefore, the capacities of the various components will not be the same. The condenser and cooling tower sizes are very similar but the condensate pump capacity will be somewhat larger in the water/steam cycle due to the makeup water requirements. Gas turbine cooling air quantity in the water/steam cycle is about one-third of the fully air-cooled version and therefore, the cooling air coolers will be smaller to a similar degree.

## 9.2 EQUIPMENT AVAILABILITY

Fabrication of the constituents of the combined cycle plant can be achieved with the gas turbine being the only item requiring major development. Pressure and temperature levels in the HRSGs and steam turbine are nominal and will pose few manufacturing problems, if any. Individual boiler feedpumps, motor-driven, are readily available. The coolers and heat exchangers, electric generators and associated switchgear, transformers, piping and control components are all state-of-the-art. The major development items are the cooling scheme and blade path design and combustion system for the high temperature turbine.

## 9.3 TURBINE EFFECTS

The basic design parameters for the air-cooled and the water/steam-cooled turbine are similar in philosophy but in some cases different in absolute values. Compressor inlet air flow is about 7% less on the water/steam-cooled turbine. Pressure ratio and turbine inlet temperatures are identical but with the addition of cooling steam into the gas path, the exhaust flows differ by 4%. The exhaust temperature comparison based on 2600$^{\circ}$F turbine inlet temperature and ISO conditions shows 1247.6$^{\circ}$F for water/steam cooling versus 1204.1$^{\circ}$F for the air-cooled version. Some of this variance can be attributed to specific heats of the two motive fluids since one contains considerably more water vapor while another portion of the difference is due to an inherent change in turbine efficiency. Table 9.3-1 displays the comparison of some operating parameters of the air-cooled and water/steam-cooled turbines.

## 9.4 CYCLE DIAGRAM AND HEAT BALANCE

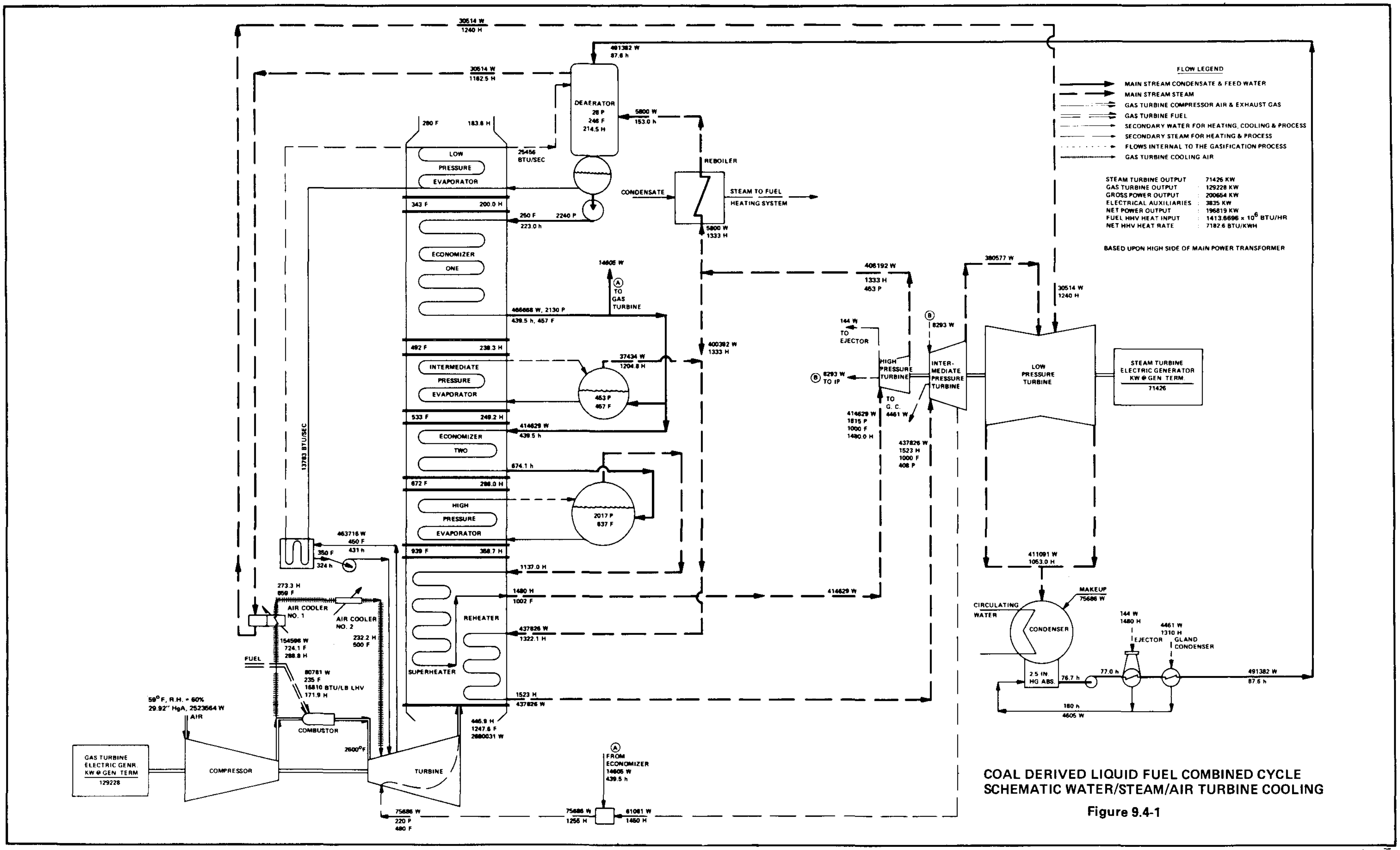
The combined cycle diagram shown on Figure 9.4-1 shows the major components, interfaces, flows, temperatures, enthalpies and pressures for the water/steam-cooled coal-liquid fired combined cycle plant. Gross kilowatt output based on one gas turbine and one steam turbine is 200,654. The electrical auxiliaries allotted for this configuration are 3,835 kw which results in a net power output equal to 196,819 kw with a net higher heating value heat rate of 7,182.6 Btu/Kwh. Using a plant configuration comprised of two gas turbines and one large steam turbine yields a net plant output of 393,638 kw.

**TABLE 9.3-1**
**A COMPARISON OF OPERATING PARAMETERS OF THE AIR-COOLED HIGH TEMPERATURE TURBINE AND THE WATER/STEAM-COOLED TURBINE**

| ISO CONDITIONS AND COAL-LIQUID FUEL | | |
|---|---|---|
| **Description** | **Air-Cooled** | **Water/Steam** |
| Compressor Inlet Air Flow ~ Lb/Sec. | 754 | 701 |
| Compressor Pressure Ratio ~ - | 14.55 | 14.55 |
| Fuel Flow ~ Lb/Sec. | 21.1847 | 22.4392 |
| Turbine Inlet Temp. ~ $^{o}F$ | 2600 | 2600 |
| Exhaust Gas Flow ~ Lb/Sec. | 775.16 | 744.45 |
| Exhaust Gas Temp. ~ $^{o}F$ | 1204.1 | 1247.6 |
| Horsepower at coupling ~ Hp | 167,673 | 176,763 |
| Thermal Efficiency Based on LHV ~% | 33.286 | 33.128 |

The turbine exhaust gas enters the heat recovery steam generator at about 1248$^{o}$F. Both high pressure and intermediate pressure steam are generated. The high pressure steam is sent to the steam turbine throttle while the intermediate pressure steam mixes with the cold reheat steam from the high pressure turbine exhaust and then enters the reheater. The reheated steam goes to the intermediate pressure turbine to continue expansion and power generation. Steam at 235 psi is extracted from the IP turbine and mixed with hot water from the IP drum to provide cooling steam at 220 psia, 480$^{o}$F for the gas turbine. The split economizer heats the feedwater so that evaporator pinch points equal to 35$^{o}$F are achieved at both pressures. The remaining energy in the turbine exhaust gas is utilized in the low pressure coil to provide steam for deaeration and feedwater heating.

As was mentioned earlier, heat is being taken away from the gas turbine stators by circulating cooling water. The rejected heat is used in the deaerator to help heat the feedwater. The heat quantity is of sufficient amount, however, to create an overabundance of energy at deaerator pressure. Therefore, dry and saturated steam at 28 psia is produced which is available for induction to the low pressure steam turbine. Direct induction of the steam is not recommended because of the potential of water carryover to and moisture erosion in the turbine blade path. To avoid the harmful




COAL DERIVED LIQUID FUEL COMBINED CYCLE SCHEMATIC WATER/STEAM/AIR TURBINE COOLING

Figure 9.4-1

potential of the saturated steam, it is first routed to the gas turbine air cooler to gain sufficient superheat so that in mixing with the main steam flow in the low pressure turbine the moisture level will not be increased. The over-abundance of energy at deaerator pressure caused by the gas turbine cooling water heat rejection is not the most desirable set of circumstances.

However, it is not possible to use the water cooler heat rejection more advantageously since the temperature level we are dealing with is about 400°F. This precludes using the energy at the intermediate pressure level because the saturation temperature at IP level is 457°F. If the IP pressure were lowered and reasonable temperature approaches were used, the drum pressure would be about 200 psia in order to utilize the lower grade heat. Since the cold reheat pressure in this instance is 453 psi, the IP steam cannot be sent to the reheater, thus creating a saturated steam induction problem analogous to that created at deaerator pressure. By increasing the high pressure turbine pressure ratio, the cold reheat pressure can be reduced to match the 200 psi intermediate pressure steam. The required pressure ratio would be roughly 9 to 1, which is greater than the maximum ratio presently employed in large reheat steam turbines.

Also, to attempt superheating the IP steam with air cooler heat as was done with the deaerator steam is not possible because there is insufficient temperature available in the air cooler. Thus, the energy is utilized in the deaerator.

A reboiler is also included in the cycle to provide a separate stream of steam for fuel heating and heat tracing. A minor amount of cold reheat steam is used to provide the required heat for this steam generation.

In Subsection 9.3, comparisons were made regarding certain specific operating parameters for the air-cooled combustion turbine and the water/steam-cooled turbine. Table 9.4-1 carries the comparison a step further and lists how certain turbine parameters affect the combined cycle.

Subsection 9.3 noted that the expander of the combustion turbine for the water/steam design was less efficient than that of the air-cooled design. But since the water/steam-cooled combustion turbine requires less compressor work due to reduced air flow and since the injected steam for cooling also does work in the expander, the end result is more output at the turbine shaft. Although less fuel is required for the work of compression in the water/steam case, the benefit is offset by the large amount of heat taken away by the cooling water in the stators of the first two stages. The energy being taken away by the cooling water is substantial and is recovered in a heat exchanger making low pressure steam.

The thermal efficiencies of the two gas turbine designs differed by less than 1/2 percent in the simple, open cycle comparison made in Subsection 9.3. (The energy

**TABLE 9.4-1**
**A COMPARISON OF OPERATING PARAMETERS OF THE COAL-LIQUID FIRED COMBINED CYCLE PLANT USING AN AIR-COOLED COMBUSTION TURBINE AND A WATER/STEAM COOLED COMBUSTION TURBINE**

| ISO CONDITIONS - COAL LIQUID FUEL | | |
|---|---|---|
| **Description** | **Air-Cooled** | **Water/Steam-Cooled** |
| Net Plant Output ~ KW | 191,603 | 196,819 |
| Net Plant HHV Heat Rate ~Btu/KwH | 6,966 | 7,183 |
| Cooling (Water) for Gas Turbine ~Btu/Sec. | 0 | 13,783 |
| Cooling (Air) for Gas Turbine ~Btu/Sec. | 7,357.4 | 2,431 |
| Cooling Steam Injected into Gas Turbine ~Lb/Sec. | 0 | 21.024 |
| Gas Turbine KW @ Generator Terminals | 122,663 | 129,228 |
| Steam Turbine KW @ Generator Terminals | 72,515 | 71,426 |

required to make the injection cooling steam was not charged to the water/steam design.) The thermal efficiencies of the two combined cycle designs is about 3% different, with the air-cooled design being the better. In the combined cycle, the injected cooling steam energy is accounted for but is not a great detriment to the water/steam cycle efficiency. This is because in the air-cooled design, the equivalent amount of steam is expanded through the steam turbine with its latent heat rejected to the circulating water. In the water/steam design, the cooling steam expands in the gas turbine and is rejected to the atmosphere. The effect of each is in the same order of magnitude. But, the energy taken away by the gas turbine cooling water is a detriment to the combined cycle, because it is downgraded to a much lower temperature level.

# SECTION 10
# MAINTENANCE

## 10.1 MAINTENANCE PROGRAM

### 10.1.1 General

The Phase I Maintenance Program consists of an outline of the approach to be taken in structuring the final maintenance program.

An optimum program should result in the most cost effective utilization of the system being serviced. The formulation of the program will consider the reliability of the design, and the functional and physical relationships between subsystems, in planning a maintenance program which will maximize plant availability. The ultimate objective of a maintenance program is to reduce forced outage time to zero, while realizing the maximum possible output from the plant. The development of the maintenance program will be based upon the following information:

- Component mean time between failure estimates based on design analyses, and past performance of identical or similar components.

- The accessability of components for servicing.

- The effect of each component upon its functional loop and the impact of that loop upon the generating capability of the plant.

This type of information can evolve during the definition and design phases of the program, and is further upgraded with data derived from the testing performed during Phase II and Phase III. With the plant in operation, the maintenance program enters its final phase, that of implementation. Further refinement of the program should be carried on during the entire operating life of the plant. This refinement is based upon:

- Revised mean-time-between-failure data resulting from the operation of new designs incorporated into the system.

- Analyses of data recorded during the operation of the plant. Such analyses should include a search for changes in performance and operating characteristics and, the identification of time-related trends for the purpose of scheduling maintenance in a timely and economical manner.

### 10.1.2 Maintenance Program Development

The two fundamental questions which a maintenance program must address are:

- What action must be taken?
- When the action must be taken?

The What action is based upon the detailed design of components and upon their physical location in the plant. What actions are defined by instructions which include the parts and equipment needed to perform the work. The preparation of these instructions requires a level of definition of the plant systems which is not within the scope of Phase I. For this reason, work on maintenance instructions will not be initiated during Phase I; however, the plant and subsystem designs have been reviewed, with respect to the allocation of adequate space and facilities to maintain the systems. Design features of the plant and equipment which provide for Maintainability are discussed in Subsections 10.2 and 10.3.

The When action is concerned with performing the required maintenance on the plant in a timely manner in order to preclude failures, while minimizing the effect of the maintenance outage time. Factors contributing to a When decision consist of the following:

- Component mean time between failure estimates which define the intervals at which components must be serviced in order to have a high probability of precluding failures.
- The effect of components upon the operation, safety, and performance of the system. This information modifies the priorities established by the mean time between failure estimates, in that components whose failure effect is tolerable from a performance, operation and safety aspect need not dictate the interval between scheduled maintenance outages.
- The location of a component in a functional (steam supply, circulating water, etc.) loop affects its maintenance cycle, in that scheduled maintenance outage periods may be dictated by other components in the loop.
- The physical location of a component can influence its maintenance cycle by virtue of its accessibility with respect to other components. The design will be such that access to critical components will require the minimal removal of less critical components.

Prior to the start-up of the plant, a program for reviewing operating data must be defined in order to detect trends in the performance of plant components. Analyses of these trends can then be used to modify the maintenance schedule. For this reason, operating instrumentation will be reviewed during the design period to assure that sufficient data will be recorded to permit detecting impending failures.

### 10.1.3 Phase I Maintenace Planning

The baseline for maintenance planning performed in Phase I consists of a Maintenance Characteristic Identification Chart which indicates the probable source of maintenance information for each of the major plant systems.

**MAINTENANCE CHARACTERISTIC IDENTIFICATION CHART**

| Major Plant System or Component | Maintenance Requirements Source |
|---|---|
| Steam Turbine | Steam turbine is similar to existing units in operation. Maintenance planning will utilize data accumulated from field operation. |
| Steam Condenser | Design is similar to existing units. Maintenance data to be extracted from field experience with these units. |
| Steam Turbine Generator | Similar units are in operation. Maintenance planning will be based upon operational data from the field. |
| Gas Turbine Compressor | Similar to W501. Maintenance requirements will be based on W501 field experience. |
| Gas Turbine Combustors | New design for higher firing temperature. Maintenance program will be based on reliability analyses and test data. |
| Gas Turbine Turbine | New design. Cooling system performance is essential for long turbine life. Maintenance information will be from reliability analyses and verification test program. |
| Gas Turbine Generator | Similar units are in operation. Maintenance planning will be based upon operational data from the field. |
| Lube and Seal Oil Systems | System is composed of proven commercially available components. Maintenance planning will be based on vendor data and field experience. |
| Starting System | Similar to the W501 unit. Maintenance requirements will be obtained from W501 field experience. |
| Heat Recovery Steam Generator | Similar to PACE units. Maintenance requirements will be based on PACE field experience. |
| Plant Control System | Design based on PACE System. Maintenance planning will rely upon field experience. |
| Balance of Plant Systems | Majority of the BOP systems are of a conventional design and are made up of proven commercial components and, the maintenance requirements for these systems will be based on component vendor data and field experience. |

## 10.2 SET DOWN SPACE AND ACCESS

The arrangement of the major components and equipment trains within the plant allows sufficient set down space to permit the simultaneous disassembly and repair of all of the major components.

The overhead cranes in the turbine hall service the assembly and disassembly of the plant turbines and generators. The set down area covered by the cranes is sufficient to support this activity.

HRSG area, ladders, walkways and platforms will provide access to smaller components for maintenance and repair. The overhauling of the larger components in this area may require the use of portable cranes and rigging equipment. Clearance is provided on all sides of clusters of major system components to permit the entry of maintenance equipment, and, for the removal of system components, if necessary. Space has been identified for the tube removal of heat transfer equipment items; and, care has been taken in the location of the auxiliary skids to allow space for the replacement of skid-mounted equipment.

## 10.3 SPECIAL TOOLS AND HANDLING FACILITIES

Special tools and handling facilities required for maintenance and repair work will be identified in Maintenance Instructions. These Instructions require a level of hardware definition which is not within the scope of Phase I; therefore, the identification of special tools and handling equipment has not been accomplished during Phase I.

During the hardware design period, the requirements for special tools and handling facilities will be reviewed with the objective of minimizing the number required.

# SECTION 11
# RELIABILITY, MAINTAINABILITY AND AVAILABILITY

## 11.1 OBJECTIVE

Dependable operation of the plant in consonance with the design objectives cited in Section 1 is the principle objective of designing for reliability. It encompasses an integration of the necessary technologies to attain a system which maximizes the return on the investment as well as meeting the necessary safety and environmental requirements.

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

As discussed by many others, the incorporation of space systems technology into industrial/commercial applications has led to broader understanding and utilization of technology. Applying this broader understanding has resulted in the use of the plant capacity factor term as a bridge between one shot or "how long" missions and those with the additional dimension of "how much." Design for RMA must therefore have as its objective the optimization of a design from the viewpoint of reliability, maintainability and availability tempered by an objective to maximize the plant capacity factor.

## 11.2 APPROACH

To assure that the above noted objectives are achieved, the technologies identified are being used as part of the design process in order to impact concept selection.

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

Fault tree analysis will be performed to establish failure mode causes for selected failure modes. This is done to augment the FMECA in areas where more detailed definition of subtier components is available and to develop a manageable use of the technique for Phase II. RMA modelling has been initiated to the extent possible during Phase I. This has been done to assess the reference design, the impact of failure mode effect removal, and to initiate effort in establishing availability criteria for the major units of the reference design.

## 11.3 FAILURE MODE EFFECTS AND CRITICALITY ANALYSES (FMECA)

Utilizing the layouts and flow diagrams developed for the system described in Section 2, a FMECA will be completed at the system level and implemented by well documented procedures.

In order to assess the importance of each failure effect, criticality factors were developed. The categories were derived on the basis of safety and effect on power output. Table 11-1 lists the chosen criticality categories.

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

**TABLE 11-1**
**CRITICALITY CATEGORIES FOR FMECA**

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

## 11.4 RMA MODELLING

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

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

In the liquid fuel reference design, two gas turbine trains (the liquefaction plants are not considered in the model) interact with a single steam turbine to comprise the system. Each train is essentially independent and contributes approximately fifty percent to the power output, thirty-three percent as direct output and seventeen percent as output from the steam turbine. In the event of an independent failure of a single train, then, power output is reduced by approximately fifty percent (exclusive of any control make-up). A model for plant availability in terms of various power ratings can be developed which underlines the inherent advantage of the reference design.

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

$$A_{(100\%)} = SG^2$$

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

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

$$a_{100} = SG^2$$

$$a_{66} = (1-S)G^2$$

$$a_{50} = 2SG(1-G)$$

$$a_{33} = 2(1-S)(1-G)G$$

where $a_i$ is the system state availability.

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

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

$$A_{66} = a_{100} + a_{66}$$

$$A_{50} = a_{100} + a_{66} + a_{50}$$

$$A_{33} = a_{100} + a_{66} + a_{50} + a_{33}$$

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

Figure 11-1 shows curves which are a plot of plant availability versus output power for various major component availabilities. These plots point out the possible advantages of the quasi-redundant configuration used for the reference design. The plot for the single unit plant shows availability improving over rated load performance for power output below plant rating, but establishing an availability that reflects all the areas of nonimprovement, such as average stress failures, procedural difficulties, maintenance, complexity, etc., which are not affected by plant output. The corresponding curve for the reference design permits comparison to a single unit plant of size equivalent to the reference design. Starting with an availability of approximately 80 percent for a plant of this size, it is seen that the single unit plant availability may go as high as 92 percent based on FEA data (Reference 2) for a plant of 1/5 size. Comparing this with the curve of $A = .90$, it is seen that significant improvement in availability is obtained for partial power operation. If indeed the assumed curve for the single unit plant is reasonable, gains in plant performance are realizable with the reference design.

### 11.4.1 Capacity Factor

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

$$CF = \sum A_i C_i$$

where $A_i$ is the availability for capacity $C_i$ over the exclusive interval i, then computes for comparison the expected capacity factor for the reference plant and also for the single unit fossil plant, the results shown in Table 11-2 are obtained. These results indicate that, for the examples used, a significant gain in capacity factor can be realized using the quasi-redundant approach of the reference design. Put another way, forced outages and maintenance on the reference design will, for the most part, result in only partial power loss.

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

### 11.4.2 Availability Design Criteria

Availability goals can be established for the principal units of the reference design using techniques like those described above. In fact, the unit availability of .93 represents a goal, which, when achieved, will result in a system availability comparable to the single unit plant availability shown in Table 11-2. Availability goals for the steam turbine subsystem and the gas turbine trains can be apportioned according to their individual reliability/maintainability characteristics, using well known techniques, in conjunction with the FMECA. For example, knowing that:

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

where $\sum_k X_k = 1$, ---

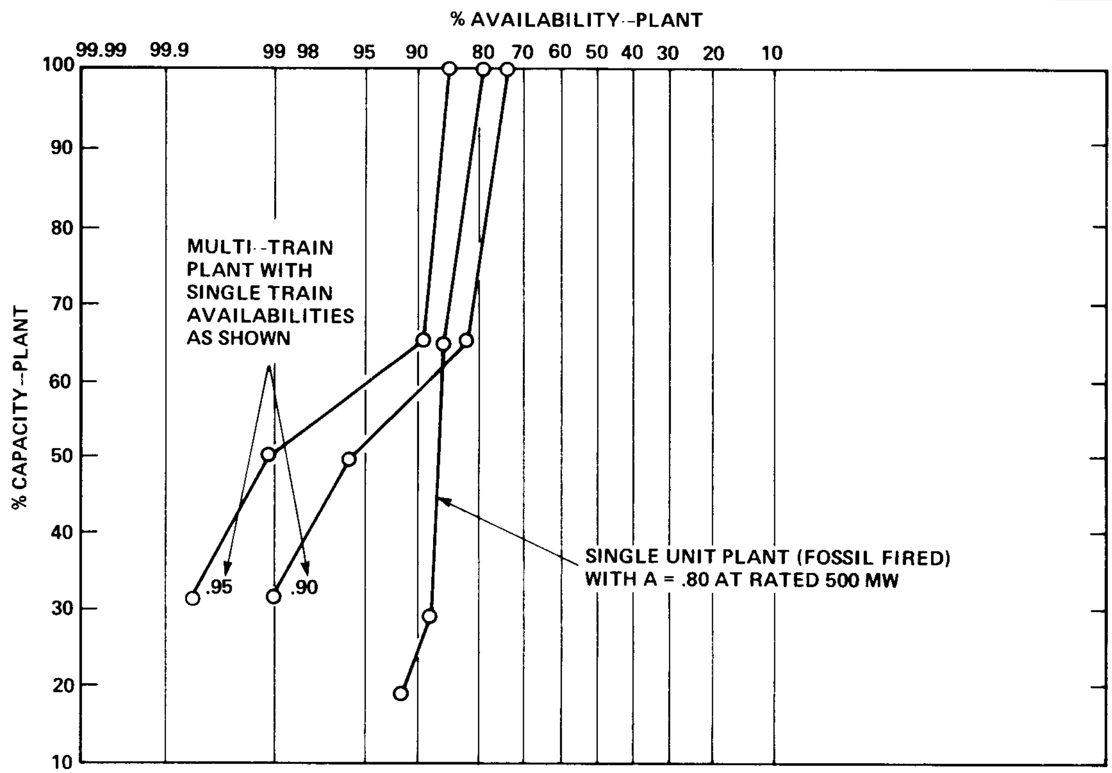
The apportionment for the two different trains becomes

$$A = A^{X_1} A^{X_2} A^{X_3}$$

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

$$S = A^{X_1}$$

$$G = A^{X_2}$$




AVAILABILITY OF THE REFERENCE DESIGN (LIQUID FUEL)
Figure 11-1

TABLE 11-2
EXPECTED CAPACITY FACTORS

| Plant | Train Availability | Plant Availability (Rated Output) | Expected Capacity Factor CF |
|---|---|---|---|
| (1) Fossil | --- | .80 | .86 |
| Comb Cycle | A .90 | .73 | .87 |
| | B .93 | .80 | .91 |
| | C .95 | .86 | .93 |

For example: With a train availability of .93 (B above):

$$\widehat{CF} = 100\,(.80) + 66\,(.061) + 50\,(.122) + 33\,(.009) = 91 \text{ percent}$$

For example, if system availability, A, is chosen as .80 (the fossil plant availability shown in Table 11-2), then the availability of each major unit is given by

$$S = .80^{X_1}$$

$$G = .80^{2X_2} \text{ and } X_1 + 2X_2 = 1$$

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

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

and $$X_2 = .4$$

$$X_1 = .2$$

Finally the goals for the major units become:

$$S = .8^{.2} = .96$$

$$G = .8^{.4} = .91$$

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

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

# SECTION 12
# OPERATING MODES

The intermediate and base load duty oil-fired combined cycle plant must be capable of operating in various modes from cold standby to power generation and back to cold standby. These modes include both steady state and transient conditions.

The steady state operating modes for the plant are:

1. Cold Standby;
2. Cold, Ready-To-Start;
3. Hot, Ready-To-Start;
4. Generation, Rated Load;
5. Generation, Part Load.

The transient operating modes occur in passing from one steady state condition to another. In addition, abnormal operating conditions must also be considered as transient cases.

The discussions that follow summarize the status of the full plant, the various subsystems within the plant, and related auxiliary equipment during the various operating modes.

## 12.1 STANDBY AND READY-TO-START

Prior to actual running operation, it is possible for the plant to be in any one of three steady state modes. These modes include: Cold, Standby; Cold, Ready-To-Start; and Hot, Ready-To-Start. A general definition for each of these modes follows.

*COLD STANDBY*

In the cold standby operating mode, the plant is shut down.

Equipment is generally placed in this mode when an extended outage is expected. Auxiliary power is available to the plant, but conservation of auxiliary power and operating materials, such as hydrogen gas, is recognized. Idle fluid systems and equipment are protected, as required by ambient temperature.

*COLD, READY-TO-START*

In this mode, the plant is shut down, but subsystem auxiliaries are in operation and fluid systems are maintained, such that the plant is capable of being started by the control room operator. In effect, this mode is one step advanced beyond the cold standby mode, resulting in fewer manual functions (less time consuming) to be performed at the local equipment level before initiating a start.

*HOT, READY-TO-START*

In the hot, ready-to-start mode, the plant is shut down but is capable of reaching rated power output in approximately one (1) hour upon a start initiated by the control room operator.

## 12.1.1 Power Block

### 12.1.1.1 COLD STANDBY

In the power block, the HRSG will be filled under a nitrogen blanket, or if freeze conditions exist, the HRSG will be drained and filled with nitrogen. All pumps, including lube oil, are "off" and the generator(s) are vented to the atmosphere.

Placing subsystem equipment in the cold standby condition requires operator functions to be performed at the equipment itself. Although the equipment must be available to start to be in this mode, startup from the control room is not possible until realignment functions, local to the equipment, are performed. These functions include repositioning local AUTO-ON-OFF switches, purging and refilling the generators with hydrogen and refilling the HRSGs.

### 12.1.1.2 COLD, READY-TO-START

In this mode, the lube oil and generator seal oil systems of the turbine generator units will be operating with hydrogen maintained in the generator and the shafts on slow roll by turning gear operation. Water will be in the HRSG and if freeze conditions exist, the boiler feedpump, heaters, and heat tracing will be in operation. The condenser will be at atomspheric pressure with the vacuum break valve open. The instrument air system will be in operation, providing control air as required.

### 12.1.1.3 HOT, READY-TO-START

The lube and seal oil systems of the turbine generator units are in operation with hydrogen in the generator(s) and the units on turning gear. In addition, the steam turbine rotor is warm, from previous operation, steam cylinder heaters are energized, to reduce heat losses and steam is being supplied to the gland seals and the main air ejectors to hold condenser vacuum.

Steam at a minimum pressure of approximately 150 psig for the glands and the air ejectors is provided by the warm HRSGs from previous operation. During this period, the main boiler feedpump is kept in operation, providing additional energy to the high pressure drum to help maintain the minimum steam pressure. Since this mode is intended to maintain equipment in a warm steady-state condition, it shall be attained only after a shutdown of operating equipment. Auxiliary equipment will not be installed to attain this state from cold standby or cold, ready-to-start.

This is a key mode in the design of an intermediate duty plant that allows a fast start-up, without a steam turbine rotor warm-up or soak period, and makes the plant ideally suited to satisfy daily or weekly industrial load demand. For this service, the longest idle period would be from Friday, PM to Monday, AM or approximately sixty (60) hours. The plant shall be capable of maintaining itself in hot, ready-to-start for this period.

### 12.1.2 Balance of Plant

#### 12.1.2.1 COLD STANDBY

Plant services, such as cooling towers, circulating and cooling water systems are shut-down and freeze protected or drained if freeze conditions exist; if a prolonged outage is expected, it is possible for certain systems having heating systems for freeze protection to be drained for energy conservation. Corrosion protective measures will be taken as final design criteria dictates.

Systems associated with on-site storage will be selectively operated as inventory or conditions dictate. This includes fuel receiving, fuel treatment, demineralizer and waste handling systems. The operation of the plant auxiliary boiler will be under manual control by the operator from the central control room and will depend upon ambient conditions and fuel systems in operation.

#### 12.1.2.2 COLD READY-TO-START

In this mode, the condensate makeup, cooling water and circulating water systems are filled and vented, and minimum circulation is maintained by operation of one (1) of the 50 percent capacity pumps of each system.

Systems associated with on-site storage, such as condensate, fuel and wastes, will be selectively operated as inventory or conditions dictate.

The auxiliary boiler will be hot, but will not be supplying any steam unless freeze conditions exist. This will provide an immediate steam source for the hogging air ejector and the fuel heater when a plant start is initiated. Start-up of plant services, such as: condensate makeup, circulating and cooling water, fuel forwarding, auxiliary boiler, auxiliary diesel-generator and auxiliary fire pump will be from the control room by the operator. The auxiliary diesel-generator and fire pump will also start automatically on an emergency alarm condition.

#### 12.1.2.3 HOT, READY-TO-START

The status of plant services in this mode is essentially the same as that for cold, ready-to-start, except that the auxiliary boiler will be augmenting the standby steam requirements as may be necessary. During this period, the operator will cycle idle pumps to verify plant readiness.

## 12.2 STARTUP

### 12.2.1 Power Block

#### 12.2.1.1 COLD, READY-TO-START TO POWER GENERATION

If the plant is in the cold standby condition, it must be first be brought up to the cold, ready-to-start condition. This transition is a series of manual operator functions, such as insuring that lube oil and hotwell water levels are proper and that the HRSG is filled, if previously drained. The generator must be purged with carbon dioxide and filled with hydrogen. Control valve sequencing and pump operation are manual functions initiated by the operator from the control room.

Once the power block equipment has been placed in a "Ready-To-Start" condition, startup of the plant is under the control of the operator from the control room. The fuel system for the combustion turbine will automatically align itself for "distillate oil" operation for start-up.

Upon start, an electric starting motor will engage and accelerate the combustion turbine shaft from turning gear speed of approximately 2 rpm to ignition speed and assist in acceleration to self-sustaining speed at which time the starting motor will shut down and disengage from the turbine generator shaft. The turbine will continue to accelerate under automatic control to synchronous speed of 3600 rpm and minimum load of 4MW on breaker closure. This minimum load is initially picked up to prevent the turbine generator from tripping due to reverse current.

As the HRSG warms up, the generated steam is bypassed to the condenser in a manner to provide a controlled warm-up of the main steam lines to the steam turbine.

During this period, condenser vacuum will be established and the generated steam is used to begin the steam turbine rotor warm-up sequence. Manual steam temperature control within the limits imposed by the turbine rotor temperature condition will be performed by the operator.

During the steam turbine warmup period, the combustion turbine may be loaded, if required by system demand. If the loading required by system demand results in combustion turbine exhaust temperatures over that required to produce the steam temperature required for the steam turbine rotor, then steam temperature going to the turbine will be controlled by allowing steam from the high and intermediate pressure drums to bypass the HRSG superheater and reheater. Steam flow will be controlled using the bypass valve, which directs excess steam to the condenser.

#### 12.2.1.2 HOT, READY-TO-START TO POWER GENERATION

With the power block equipment in the Hot, Ready-To-Start mode, it shall be possible to start and load the plant completely from the control room. The starting sequence will be as previously described in the "Cold, Ready-To-Start to Power Generation" section, except it will not be necessary to establish condenser vacuum or roll the steam turbine rotor for a warm-up period.

Depending upon the steam turbine rotor temperature at the time of start-up, it may be necessary to load the combustion turbine generator and gasifier to achieve the steam temperature required for initial roll of the steam turbine.

### 12.2.2 BALANCE OF PLANT

#### 12.2.2.1 COLD, READY-TO-START TO POWER GENERATION

Bringing the balance of plant systems up to the cold, ready-to-start condition from cold standby requires a series of manual operator functions to be performed as in the power block. Startup of idle system pumps to bring the system up to 100 percent capacity will be performed manually from the control room.

The distillate fuel forwarding pumps will be started on the start signal for the combustion turbines. At the same time, steam from the auxiliary boiler will be admited to the fuel heaters associated with the coal-derived oil and to the hogging air ejector.

Steam generated by the HRSG (s) will gradually reduce the steam coming from the auxiliary boiler to zero.

At approximately minimum load on the combustion turbine, the operator will initiate an automatic fuel transfer to the coal-derived liquid fuel, provided the supply temperature condition is satisfied. Startup of the demineralizer and fuel treatment systems will be performed locally at the equipment by an assistant operator. Fuel receiving and waste handling will also be local manual functions. Operation or throughput of the demineralizer and fuel treatment systems is independent of plant load and is set locally at the equipment.

#### 12.2.2.2 HOT, READY-TO-START TO POWER GENERATION

The events and functions to be performed for a startup from a hot, ready-to-start condition are the same as from a cold, ready-to-start condition, except, as relating to pulling a condenser vacuum. In the hot, ready-to-start condition, the condenser is under vacuum and the steam supply to the primary air ejectors may be augmented by steam from the auxiliary boiler.

## 12.3 GENERATION, RATED LOAD

In this mode, the plant is operating and generating power at rated power output.

### 12.3.1 Power Block

Once the turbines, both combustion and steam, have reached or exceeded minimum load and the operator has selected rated load, power output will automatically be increased to the rated output of each generator for the existing ambient conditions. At this point, the plant is generating rated power at its higher efficiency. All fluid systems, such as steam, water and fuel gas will be in a balanced steady state condition.

### 12.3.2 Balance Of Plant

With the plant generating power at rated load, critical fuel and water services to the power block are operating at 100 percent capacity. The demineralizer plant will normally be operating although down periods can be tolerated, depending upon demineralized water storage and demand. The reboiler will be providing the steam to the fuel treatment system, allowing the auxiliary boiler to be secured. Fuel receiving and waste handling will be conducted as conditions dictate.

## 12.4 GENERATION, PART LOAD

### 12.4.1 Power Block

Operation at load points other than full rated power of the plant shall be performed in a sequence so as to accomplish optimum performance within operating limits of the equipment.

The combustion turbine will have adjustable compressor inlet guide vanes which, upon closing, will reduce mass air flow, fuel flow and turbine power at essentially a constant turbine exhaust temperature. In turn, this will reduce steam production in the HRSG, with a minimum reduction in steam temperature. Steam turbine output is reduced, but minimizing thermal cycling and its effect on operating life.

From rated plant output, plant load will first be reduced by closing the compressor inlet guide vanes of the combustion turbines. Load reduction down to approximately 75 percent can be obtained with this type of operation. Further load reduction to 50 percent is obtained by reducing the firing temperature of the combustion turbines. Optimum plant performance at approximately 50 percent load may be reached by shutting down a combustion turbine-HRSG train and restoring the on-line unit to full rated power.

### 12.4.2 Balance Of Plant

At reduced plant loads, it will be necessary to reduce the operating capacity of the demineralizer and the fuel treatment system. Should the throughput be reduced below efficient operating level for an extended period, it may be necessary to place these systems on intermittent duty.

Depending upon the load point and ambient conditions, the operator may reduce the plant auxiliary electrical load by shutting down one of the half-size pumps associated with the condensate, cooling water or circulating water systems. Cooling tower fan operation will be automatically controlled.

## 12.5 SHUTDOWN

In removing the plant from power generation, it will be returned to one of the non-running steady state modes as defined earlier under Paragraph 12.1.

### 12.5.1 Power Block

#### 12.5.1.1 POWER GENERATION TO HOT, READY-TO-START

As previously stated, it is only possible to attain the Hot, Ready-To-Start mode from the Power Generation mode. During this transition, certain components of the plant; namely, the steam turbine rotor, heat recovery steam generator, and the condenser which are warm, can be maintained in an extended warm condition to permit a fast plant startup only possible without a steam turbine rotor warm-up.

To place the Power Block equipment in the Hot, Ready-To-Start condition from a generating load point, steam turbine load will first be reduced by automatic closing of the inlet guide vanes on the combustion turbine compressor as the fuel is decreased. This will hold the combustion turbine exhaust temperature high but reduce gas flow through the boiler, thus generating less steam. The combustion turbines will then be further unloaded with the steam generated in the boiler(s) bypassed to the condenser.

On shutdown, stack covers on the heat recovery boilers shall be closed at approximately 600 rpm of the combustion turbine in order to hold the residual heat of the turbines and HRSGs. The boiler feedpumps shall remain operating, as will the air ejectors and the steam turbine gland steam system. Both combustion and steam turbine-generator units will be maintained on turning gear with rated generator hydrogen pressure held.

The Hot, Ready-To-Start period on the Power Block equipment will end when any one of the following conditions occur:

a. Loss of condenser vacuum;

b. Loss of gland steam;

c. Steam turbine rotor temperature below minimum warm-up temperature.

#### 12.5.1.2 HOT, READY-TO-START TO COLD, READY-TO-START

With the plant in the hot, ready-to-start mode, the next lower progression mode of cold, ready-to-start is obtained either by changing conditions as outlines in Paragraph 12.5.1.1, or by operator selection. In either case, the operator from the control room will initiate the following:

1. Shutoff gland steam to the steam turbine and open the steam turbine bypass valve.

2. Open the vacuum break valve of the condenser.

3. Vent the generators to 0.5 psig hydrogen pressure minimum.

The combustion and steam turbine lube, seal oil and turning gear systems will remain in operation and the instrument air system will be left in automatic. The stack covers on the HRSGs may be left closed if ambient temperatures are below freezing to minimize draft through the combustion turbine and HRSG.

#### 12.5.1.3 COLD, READY-TO-START TO COLD STANDBY

In placing the power block in the cold standby condition from the cold, ready-to-start mode, the operator from the control room will secure all pumps and realign control valves. The turbine lube and turning gear systems must be maintained for the specified rotor cooldown periods before they can be secured. In addition, the generators must be purged with carbon dioxide before the lube and turning gear systems are shut off. The HRSGs will be placed under a nitrogen blanket and the instrument air system will be secured. Manual functions local to some of the equipment will be performed, such as the opening of drain valves and repositioning on-off-auto switches at local control panels. Environmental systems of equipment and enclosures will remain in automatic for protection of equipment.

### 12.5.2 Balance Of Plant

Return of the balance of plant equipment to one of the non-running steady state modes is performed manually by the operators. In general, the function follows the detailed shutdown sequence of the power block and is performed upon the discretion of the operator when a safe or other demanding condition is satisfied. For example; it would be unwise to secure the cooling water system entirely, immediately after a shutdown, even if the final state is to be cold standby. The residual heat remaining in the turbines and transferred to the lube and seal oil systems must first be dissipated.

## 12.6 ABNORMAL CONDITIONS

### 12.6.1 Power Block

Whenever a system trip or malfunction occurs, a transient operating condition will exist. Upon such an event, the equipment or plant shall be designed to automatically react by at least one of the following, in order of priority:

a. System Realignment — such as transfer to a back-up system.

b. Removal of generating equipment from the electrical system — by generator breaker opening on a generator or switchyard electrical fault.

c. Steam bypass to condenser on a steam turbine trip.

d. Turbine-Generator Trip to Standby Condition — in the event of a mechanical malfunction, such as excessive vibration, which would be damaging if continued operation were allowed.

### 12.6.2 Balance of Plant

A trip or malfunction in a balance of plant system shall cause automatic steps to be taken to minimize the effect on overall plant operation. For the most part, the final corrective measure to maintain plant operating integrity will be based upon the decisions of the operator. The first automatic action that will be taken will be a transfer to a redundant component, such as a pump. The second automatic action that will be taken is to signal the operator through supervisory instrumentation of the malfunction. This will alert the operator to take corrective action if he has the option. Such action could include reducing plant load in the event of a restriction on condenser circulating water, shutting down one of the circulating water pumps correcting the problem, and restoring all systems to original status.

Balance of plant equipment will be designed for self-protection in the event the operator does not take corrective action after an alarm signal.

# REFERENCES


**Reference Number**

1 ECAS - Energy Conversion Alternative Study MAS-3-19406

2 "A Report on Improving the Productivity of Electric Power Plants" prepared by: FEA Inter Agency Task Group on Power Plant Reliability, March 1975.