Entrained Gasification Combined-Cycle Control Study
Volume 1: Summary of Results and Conclusions

AP-1422, Volume 1
Research Project 913-1

Final Report, June 1980
Work Completed, October 1979

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ABSTRACT

In this study, two control strategies were evaluated for a new type of electric power plant as part of a large utility network. Specifically, an entrained coal gasifier fuels a gas turbine/steam turbine combined-cycle unit forming the integrated plant which was simulated by computer to analyze alternative control strategies. Transient operation of this gasification-combined-cycle (GCC) plant was studied to determine open-loop response as a stand-alone plant, as well as closed-loop response while functioning in a typical utility power system. GCC plant performance during specified operating contingencies, such as equipment trip or emergency shutdown, was also studied.

The major features of the GCC plant as simulated include:

- A single-stage entrained (Texaco) gasifier fed concurrently with a coal-water slurry and gaseous oxygen.
- A cold gas cleanup train with a physical absorption (Selexol) system for selective sulfur removal.
- Advanced gas turbine design based upon 2400°F combustor outlet temperature.

The design point for this project was based on flowsheets developed for an earlier study (see EPRI Report AF-642 Economic Studies of Coal Gasification Combined Cycle Systems for Electric Power Generation). The flowsheets were modified for this control study to accommodate two full-sized gas turbines with two heat recovery steam generators; other plant components were scaled accordingly to match resulting gas turbine capacity.

Conclusions may be summarized as follows:

- The GCC plant may be controlled satisfactorily in either gasifier-lead or turbine-lead control mode.
- The absorber column consistently removed 90 percent of the hydrogen sulfide (H_2S) in the raw fuel gas produced from high sulfur Illinois coal during the closed loop control runs.

- GCC plant pressure control must be installed to minimize plant pressure transients at the absorber column in the Acid Gas Removal Unit.

- The local controllers adequately maintained the GCC plant operation during all the emergency upsets which were examined.

- The GCC plant responds well to typical variations in electric power demand, i.e., gradual changes for daily load following and successive rapid changes for tie-line thermal backup and frequency regulation.

- Supplemental fuel gas storage is not required.

- The design and operating characteristics of the oxygen plant (which was not explicitly simulated) can affect the response time of the GCC plant. Response rates of three percent per minute at the oxygen plant would make the GCC plant very responsive to electrical load changes.

A separate study of oxygen plant design alternatives is recommended to evaluate potential improvements in transient response rate and turndown capability, since the specific tradeoffs between process economics and more flexible dynamic operation are not clear. Ultimately, the effects of the oxygen plant response upon fuel gas composition during typical GCC plant load changes should be examined.

EPRI PERSPECTIVE

PROJECT DESCRIPTION

Coal gasification-combined-cycle (GCC) power plants represent a major new alternative for converting fossil energy as a source of electric power. To operate effectively on a utility network, however, such future power plants must be able to perform load-following maneuvers. It is important for the commercial development of the technology to establish this capability at an early point, even before large demonstration plants are built. Therefore, the dynamic response and control strategies for GCC power plants have been evaluated in studies made possible by using computer simulation. One such analysis of a GCC system, based on an entrained flow gasifier of the Texaco type, was carried out by Fluor Engineers and Constructors, Inc. and Westinghouse Electric Corp. The results of that Research Project, RP913-1, are described in this final report.

In a similar study under RP914-1, General Electric Co. is analyzing the dynamics and control of GCC systems based on moving-bed gasifiers. Separate case studies for a Lurgi-type reactor contrast the results of dry ash, air-blown gasification with oxygen-blown, slagging operations.

The results of both control analyses (RP913-1 and RP914-1) are being incorporated in a simulation study (RP1133-1) by Philadelphia Electric Co. on the effects of substituting GCC power plants for conventional fossil units operating on an actual utility network, the Pennsylvania-New Jersey-Maryland interconnection.

Other supporting studies involve experimentation or detailed simulation to define the dynamic response of individual components of the fuel-gas process. Directly related to the entrained GCC process, for example, are experimental trials of the Texaco pilot plant gasifier and the Selexol sulfur-removal system at Texaco Inc.'s Montebello research facility (RP985). These pilot plant results are being used, in turn, to develop detailed simulation models for the gasifier (RP1037) and sulfur-removal system (RP1038).

The aim of this overall research effort investigating system control capabilities of entrained GCC power plants is to minimize the risks associated with uncertainties during the scale-up process. Consequently, there should be a direct benefit to the design and operation of the 100-MW GCC demonstration facility planned for the joint project (RP1459) with Southern California Edison Co., Texaco, and EPRI.

PROJECT OBJECTIVES

The major purpose of the study was to define the system control requirements for entrained GCC power plants to operate reliably and effectively as part of a large interconnected utility network. This work included determining the inherent dynamic response of a GCC plant with closely interacting components and evaluating alternative control strategies for the plant to perform typical load-following maneuvers required by the power system. Also to be studied were the effects of contingency operations of the GCC plant under emergency conditions following the trip (or loss) of various major plant components.

As an implied intermediate goal of the GCC control analysis, mathematical models and computer simulation programs were to be developed for the entrained GCC plant and the electric power network. Originally, both oxygen-based and air-based entrained GCC plants were to be simulated. However, the scope was later changed, curtailing the air-blown case study to expedite the oxygen-blown case study. This was consistent with increased emphasis on oxygen-based gasification, as exemplified by the proposed Cool Water project (RP1459) and the decreased emphasis on an air-based entrained GCC plant with fuel gas of inherently lower heating values.

PROJECT RESULTS

Rarely have studies of the process dynamics and controllability of a large, new integrated plant been attempted before it has even been designed, let alone before the technology has been scaled to commercial size. However, the results of such a priori analyses using computer simulation, as shown here, demonstrate that GCC systems indeed have the potential for rapid stable response to meet power system maneuvering requirements. Moreover, this result has been achieved for a highly integrated GCC plant with closely interacting components. That is, the plant was readily controllable without decoupling the fuel-gas process from the combined-cycle equipment or imposing intervening gas storage capacity as a buffer. The economic advantages of low-heat rate resulting from process integration are thereby retained.

The major components of the fuel-gas process, including the gasifier and sulfur-removal system, appeared satisfactorily responsive and controllable. This has enabled alternate control strategies (i.e., either turbine-lead or gasifier-lead modes) to be applied successfully to gradual response rates typical of daily load-following operation or to more rapid changes typical of tie-line backup or frequency regulation.

The oxygen plant was not explicitly simulated (i.e., oxygen production rates and power consumption were predetermined and allowed to vary only within set limits). However, oxygen plant dynamics were shown to be important in establishing the overall GCC plant response. Typically, high-purity oxygen processes have not been operated in a variable-production mode. Therefore, it has been recommended that the design and operation of oxygen plants be evaluated regarding supply requirements for GCC application.

EPRI studies are already underway with major American vendors to ascertain the maximum response rates of existing oxygen plant designs (RP1806) and potential improvements to improve response rate (RP239-5). For example, by relaxing requirements for high-purity oxygen it may be possible to supply gaseous oxygen at rates corresponding to the varying feed rates required by the gasifier, i.e., without the expensive alternative of storing and evaporating liquid oxygen.

The gas turbine design used for this plant was an advanced design with 2400°F combustor outlet temperature. This was an expedient choice based on the availability of design flow sheets for a GCC plant with such a turbine. It was judged early-on that controllability of this advanced plant might be more demanding because of more potential for plant integration than with a current turbine design (i.e., 2000°F combustor outlet temperature).

Two alternative control strategies, including turbine-lead and gasifier-lead control modes, were successfully applied to operate the GCC plant as simulated. However, no effort was made in this study to develop an optimal control policy that, for example, might evolve from some form of coordinated control. The study of GCC plant integration into a utility network by Philadelphia Electric (RP1133-1) will help determine further control requirements.

This final report has been published in three separate volumes to accommodate different audiences. The first volume, Summary of Results and Conclusions, presents salient features and results of the control analysis; a wide audience interested in GCC plant application will find this executive summary useful. For those who have a need to apply the results directly, more detailed output from specific simulation runs is contained in the second volume, Results. A third volume, Model Descriptions, presents information on the mathematical development of the simulation models for those who have a need to conduct similar analyses.

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VOLUME III MODEL DESCRIPTIONS

SUMMARY AND CONCLUSIONS

In this study, control strategies were evaluated for a new type electric power plant for compatible operation as part of a large utility system. Two control options were studied by simulating an oxygen-blown entrained gasification-combined-cycle (GCC) power plant operating in a typical power system environment. Contingency behavior of the GCC plant was also investigated. Both control strategies, gasifier lead and gas turbine lead, satisfactorily meet power system needs within the limits of equipment operating constraints.

The study was performed using advanced gas turbine designs with a 2400°F combustor outlet temperature. The GCC plant for the control study contained two full-sized gas turbine/heat recovery steam generators and the associated main plant components scaled to match the capacity of the turbines. The design configuration was similar to the flowsheets in Case EXTC (oxygen-blown Texaco coal gasifier/combined-cycle power plant - slurry feed) as reported earlier (see EPRI Report AF-642, Economic Studies of Coal Gasification Combined-Cycle Systems for Electric Power Generation).

This study was based on advanced 2400°F gas turbines to permit the use of an existing plant design study, thereby significantly reducing the effort. These turbines, with high exhaust temperatures, have been married to coal gasifiers in a way such that there is a great degree of heat integration between the fuel gas processing plant and the combined cycle unit. Therefore, overall control concepts for this highly integrated design are believed to apply to cycles based on commercial gas turbines (with temperatures of approximately 2000°F), which adopt a similar "sliding-pressure" concept for steam turbine control.

THE SIMULATED PLANT

The entire gas train from the oxygen compressor discharge to the heat recovery steam generator was simulated. All steam consumers and generators were included. The fuel processing plant water balance was closed to account for heat in the process condensate. Mathematical model representations were generated for each of the major components of the GCC plant. The models were interconnected very much like an actual plant and incorporated into a model of a large utility network to evaluate the suitability of the GCC plant controls. The network model consisted of two areas (operating at a single frequency) using boiler plants with reheat steam turbines for all the non-GCC capacity.

The main plant consisted of oxidant feed, gasification, gas cooling, acid gas removal, and combined-cycle power generation units. The oxidant feed unit was composed of two parallel operating gaseous oxygen trains (at a nominal scale factor of 74 percent of EXTC) plus a liquid oxygen evaporator (sized equivalent to 74 percent of one gaseous train in EXTC). The gasification unit consisted of two parallel operating trains (at 74 percent). The gas cooling and acid gas removal units were single trains (at 88 percent). There were two parallel full-sized gas turbine/heat recovery steam generator sets and a single steam turbine (at 29.5 percent).

Dynamic simulation of the oxygen plant's cryogenic separation of oxygen from air is not included in this study, rather the power consumed by the air and oxygen compressors was calculated as well as air flow, oxygen flow, liquid oxygen flow to a vaporizor and steam demand for the oxygen plant. Oxygen concentration was assumed to be 98 percent pure. Gasous oxygen from the compressor and the vaporizor both feed an oxygen header, while the gasifier oxygen is supplied from this header. A pressure controller on the header increases or decreases oxygen production accordingly. The gaseous production rate can change up to 25 percent per hour (0.42 percent per minute); the liquid flow can change 10 percent per minute. The gaseous oxygen plant can supply two gasifiers; the liquid evaporator can supply one-half as much. The evaporator is constrained to operate between 20 and 100 percent of its design flow.

The fuel processing plant steam generation is integrated with the combined-cycle system. The steam system operates at four levels:

High-Pressure	-	1422 psia, 900°F (pressure set point varies per a linear throttle flow-pressure schedule)
Intermediate-Pressure	-	342 psia, 1000°F (varies with turbine flow characteristic)
Medium-Pressure	-	114 psia
Low-Pressure	-	65 psia

Superheat temperature control is implemented by passing HP saturated steam around both superheaters through a common bypass line. Reheat temperature control is similarly achieved with a single bypass line around both reheaters.

"Sliding pressure" operation for the steam turbine has been selected on the basis of experience with the Westinghouse PACE 260 combined-cycle plants. The throttle valve pressure set point is scheduled to vary linearly with steam flow above a minimum pressure of 300 psia. The interceptor valve is wide open. During steam turbine trips when header pressures are significantly above the steam turbine throttle pressure schedule, the steam turbine bypass valves open to letdown steam to the condenser hotwell.

With the "sliding pressure" steam turbine, steam pressure changes significantly with load. In fact, when the two gas turbines were tripped to full speed no load, the IP steam header pressure dropped by more than a factor of two. Since superheated IP steam was envisioned to drive the compressors in the oxygen plant, there is a conflict between the steam conditions and the capabilities of steam drivers to keep the oxygen plant running. Several solutions could be considered:

- Switch the oxygen plant steam drives to electric drives.
- Convert the steam turbine to "constant IP header pressure" operation.
- Trip the steam turbine when header pressure falls.

We believe that the motor drive option is preferred. Motor drives facilitate plant startup, since the oxygen plant can be brought on line prior to operation of the gasification combined-cycle system.

The steam turbine is in "follow" mode: The throttle valve regulates inlet pressure on a schedule with flow, the interceptor valve is wide open, and the turbine consumes all available steam.

The net heat rate for the GCC power plant model has been estimated from the variables at the end of a benchmark run to "line-out" the plant at the Case EXTC design conditions (see AF-642). The heat rate is 8806 Btu/kWh. This compares well with the 8813 Btu/kWh published in AF-642.

For the benchmark case the GCC plant gross power is:

Gas Turbine Power #1	113.1 MW	32%
Gas Turbine Power #2	113.1	32
Steam Turbine Power	127.4	36
Gross Power	353.6 MW	100%

Steam conditions and flows were reasonably close to the design values.

	This Study	CASE EXTC
HP Steam Pressure, psia	1422.3	1464.7
HP Steam Temperature, °F	900	900
HP Steam Flow, lb mole/s	14.8	15.1 (2/7 EXTC)
IP Steam Pressure, psia	342.3	400
IP Steam Temperature, °F	1000	1000
IP Steam Flow, lb mole/s	10.3	11.3 (2/7 EXTC)

The heat rate of the GCC plant model at 155.9 MW (44.1 percent of full load) is 12,855 Btu/kWh. The shape of the GCC plant heat rate curve follows the characteristics of gas turbine curves. Very little degradation of heat rate is experienced until the gas turbine inlet guide vanes are closed, then the heat rates deteriorate rapidly.

PLANT CONTROL CONCEPTS

The station controller receives input from the network model as "power demand," and input from the fuel processing plant as "plant pressure," and sends output signals to the oxygen and slurry flow controllers at the gasifiers and speed/load signals to the gas turbine controllers. Each gas turbine controller receives the output of a plant pressure controller as direct input at all times. This plant pressure controller output feeds a gain-only controller in the gas turbine which is active in the pressure mode, during mixed fuel operation or when overriding other gas turbine controllers in the event of a severe depressurizing of the process plant.

The plant pressure control point was selected to be just downstream of the Selexol absorber to minimize pressure changes at the Selexol column as gas flow varies. The plant pressure profile for two plant flow rates is as follows:

Steady-State Pressure Profile Versus Percent Design Flow Rate

Percent Flow	Pressure, psia Gasifier	Selexol Outlet	Expander Inlet	Gas Turbine Inlet
100%	612.9	546.6	509.1	324.7
60%	567.7	546.6	534.0	324.7

Selecting the plant pressure control point just downstream of the Selexol unit minimizes the pressure excursions at the Selexol unit during load following. This is required to maintain the percent sulfur removals achieved in this study.

Properly instrumented and maintained absorption units, of which Selexol is one type, are reliable and function effectively in process plants with little operator attention. As a matter of fact, many of these units in natural gas producing fields operate unattended. Nonetheless, for more dynamic environments such as power plants, the selective removal of H_2S in the presence of CO_2 is a more difficult task. From this model, where we have only studied the absorber and not the regenerator, it appears that 90 percent sulfur removal in closed loop station control will be achieveable in a real plant.

Our study did not include carbonyl sulfide (COS) which is normally about 10 percent of the sulfur in the gas, rather we converted all coal sulfur to hydrogen sulfide (H_2S). Nonetheless, we feel the results are qualitatively correct and have confidence that 90 percent removal can be obtained. The equipment should be designed to provide the ability to remove more than 90 percent of the sulfur to be able to adjust the average sulfur removal level in the plant.

The study was performed in three phases. First the GCC plant models were connected and local controllers tuned to provide manual operation in "open loop" control; that is, without the station controller and network models. After this, the network (with tuned controllers) was connected to the GCC plant via the station controller to investigate the "closed loop" control. Since all controllers were previously tuned, the station controller was ready to use after selecting the ramp limits and steps associated with power error and pressure error. Finally the GCC plant performance characteristics for "contingency operation" were investigated. All emergency trips studied were initiated at full load.

Open Loop

With the station controller turned off and the network disconnected from the GCC plant, the characteristics of the GCC plant were investigated. In all of these investigations, the gas turbines are in pressure control mode, i.e., the plant pressure controller is regulating the fuel flow to the gas turbines to maintain plant pressure. Operating conditions are then established by manually changing the set points of the oxygen flow controllers at the gasifiers.

Closed Loop

The GCC plant control concepts (station controller) investigated are:

- Turbine Lead Mode. In this configuration, the combustion turbine fuel valve responds directly to changes in power demand, i.e., fuel flow to the turbine is controlled by power demand. This is typical of the control strategy practiced for liquid fuel fired combined-cycle plants. Gasifier pressure is restored through the oxidant and coal slurry feed flows reacting to the plant pressure error.

- Gasifier Lead Mode. This mode of control requires that oxidant and coal feed to the gasifier respond to changes in power demand. For this case, the fuel valve between the gasification plant and each gas turbine reacts to pressure control to maintain plant pressure.

In the simulations involving the network, the output from 5.65 GCC plants (as modeled) is connected to Area I of a two area network. For the two control modes, the same four load changes were made in the network model. Two runs were made at full GCC load: a 20 percent decrease in Area I load ramped down at 4 percent per minute, and a 20 percent step decrease in load. Two additional runs were made at the selected minimum GCC operating load: a 20 percent increase in Area I load ramped up at 4 percent per minute, and a 20 percent step increase in load.

The eight closed loop control runs indicate the gasification-combined-cycle plant responds readily to network demands.

Contingency Operations

Eight contingency or emergency operation runs are presented, one each for: loss of one gasifier, oxygen plant single train trip, trip of one gas turbine electrical load, trip of two gas turbine electrical loads, trip of steam turbine electrical load, loss of all electrical load, loss of one Heat Recovery Steam

Generator (HRSG), and loss of one gas turbine gas fuel valve where the gas turbine is rapidly transferred to oil firing. In general, the eight contingency runs demonstrate that the local controllers maintain all sections of the process plant in operation during the severe dynamics associated with the loss of various items of equipment.

The deaerator controls should be designed to handle large BFW flow transients. When a steam turbine trip occurs, the BFW and makeup flows increase on the order of 50 percent to provide desuperheating water. Since the deaerator normally receives hot makeup water from heat exchangers in the fuel processing plant, there is now a significant deaerator heat imbalance. Namely, when water flow increases, it can not be heated to the same temperature. The deaerator needs an additional input of heat to prevent the deaerator pressure from decreasing, thereby decreasing the net positive suction pressure (NPSH) of the BFW pumps. The deaerator control scheme should be arranged to limit the decrease in deaerator pressure.

CONCLUSIONS

As simulated, the GCC plant is observed to be very responsive to closed loop control; that is, when separated from constraints on oxygen supply. When more power is needed, more gas is produced in the gasifier. Higher gas flow means more steam is produced in the fuel processing plant, more power is made in the gas turbines and more steam is made in the Heat Recovery Steam Generators. Therefore, more steam power is produced and, with the increase in gas turbine power, plant power generation increases. Since the incremental power required in the oxygen plant is less than the corresponding increase in GCC plant output, more power is sent to the network.

These variables act in the same direction most of the time during transient operation. With an increase in gas flow, steam production in the fuel processing plant begins to increase within a few seconds and the gas turbine power within 10 seconds, but the HRSG steam takes much longer. As a result, the plant response to power demand is quite fast. The gas turbine varies almost directly with gasifier flow changes. With the gas turbine providing 64 percent of the total plant power generation at full load, the gasifier flow is closely related to total plant power output. Therefore, very little difference in the alternative station control schemes was detected.

The heating value of the product gas varied only slightly with changes in the throughput, i.e., less than one percent during major transients. Therefore, the controls are not required to compensate for nonlinear heating value effects, as observed during flow transients in moving bed gasifier systems. In fact, the gas composition from the Texaco gasifier model was essentially constant and independent of thoughput. This will be feasible in a real plant by providing tight ratio control for the oxygen and coal slurry feed streams to the gasifier. Of course, this also requires that the coal-water slurry system be designed to provide uniform feed stream to the gasifier, that coal quality does not change significantly, and that the oxygen supplied in the oxidant stream remains essentially constant. Note that if oxygen concentration should vary, then oxidant flow must be compensated accordingly.

The open loop ramp runs showed that the gas turbine power response corresponded directly with gasifier feed flow changes. Therefore, it appears that the difference in plant response to power demand under the alternate modes (gasifier-lead and turbine-lead) is virtually indistinguishable. That is, under gasifier-lead mode when power demand signals increased gasifier flow, gas turbine power output increases rapidly. Nearly identical results (except for small time lags) occur under turbine-lead mode when power demand signals the turbine directly to increase power output, and the gasifier flow increase follows later via plant pressure control.

Since both control modes operated the plant satisfactorily, to select an appropriate control strategy one must simply look for advantages beyond overall plant response. Clearly, this study merely sought to demonstrate the feasibility of certain control strategies and did not attempt to devise an optimal control strategy. It is entirely possible for a specific GCC plant design that further study might produce an optimal control policy via some form of coordinated control.

Closed loop operation was successful because the gas turbine controllers performed many logic functions necessary for smooth plant operation. For a real plant, the gas turbine controller must be developed with much care. For this study, pressure control was added to the standard Westinghouse gas turbine controller. Tracking features with offsets were also added to synchronize the outputs of the speed/load controller, pressure controller and temperature limit controller. This minimized transients introduced when one of these controllers was required to override another.

For simple closed loop control, additional control logic is necessary to correct for the emergency situation caused by a shortage in oxygen supply when oxygen demand is increased by the station controller. For example, when an oxygen plant trips, demand is so much greater than supply that the oxygen header between the gasifier and oxygen plant will be depressurized if the signal to the gasifier flow controllers is not reduced. The required logic is very simple to apply in gasifier-lead mode; this favors the gasifier-lead option.

However, when speed error signals are used for frequency regulation, the turbine-lead mode is favored. If a speed error signal is sent directly to the gas turbine, the volume of the fuel processing plant serves as a buffer to dampen the rates of change of flow at the gasifier. Large speed error signals should not be sent to the gasifier flow controllers directly since oxygen demand might then exceed supply enough to depressurize the oxygen header. That is, under these circumstances, control of the overall fuel gas process must be more closely coordinated.

The major purpose of limiting the ramp and step changes at the station controller is to restrict flow changes imposed on the gasifier. Oxygen supply should closely match demand to prevent depressurizing the header; therefore, the GCC plant response largely depends on the effective rate of change of the oxygen supply.

All control results were achieved using anticipated volumes for piping and equipment. A volume for supplemental fuel gas storage was not required.

In summary, we have concluded:

- The GCC plant may be controlled satisfactorily in either gasifier-lead or turbine-lead control mode.
- The absorber column consistently removed 90 percent of the hydrogen sulfide (H_2S) in the raw fuel gas produced from high sulfur Illinois coal during the closed loop control runs.
- GCC plant pressure control must be installed to minimize plant pressure transients at the absorber column in the Acid Gas Removal Unit.
- The local controllers adequately maintained the GCC plant operation during all the emergency upsets which were examined.
- The GCC plant responds well to typical variations in electric power demand, i.e., gradual changes for daily load following and successive rapid changes for tie-line thermal backup and frequency regulation.

- Supplemental fuel gas storage is not required.
- The design and operating characteristics of the oxygen plant (which was not explicitly simulated) can affect the response time of the GCC plant. Response rates of three percent per minute at the oxygen plant would make the GCC plant very responsive to electrical load changes.

We recommend that EPRI continue to investigate improved design characteristics of the oxygen plant which would permit the oxygen plant to vary gaseous production rates more readily. For this study the throughput of the air separation unit was permitted to move 25 percent per hour (0.42 percent per minute). This rate, by itself, was insufficient to satisfy changes in oxygen demand at the gasifiers. It is believed that air separation plants can respond more quickly if the process design of the plant is altered. Specifically, the oxygen purity, when reduced from 98 percent to 95 percent, simplifies the separation process. Fewer trays are required in the distillation tower and the separation simplifies to separating a mixture of oxygen and argon from nitrogen, a pseudo binary fractionation. This different design should respond much faster than 25 percent per hour with minimal variations in oxygen concentration. The air compressor and especially the oxygen compressor (in each train) will have to have antisurge controls and will have to be designed with spill-back or blow-off to handle the net flows required by the gasifiers over full range of power demand.

Further study of an oxygen plant should be commissioned to calculate the composition variations which would accompany the demand variations targeted in this study:

- For 20 percent load step in the network (model) simulating thermal backup - 3 percent of the design flow per minute for 3 minutes.
- For 4 percent per minute load ramp for 5 minutes in the network (model) simulating morning pickup - 2 percent of the design flow per minute for 5 minutes.

Section 1

INTRODUCTION

PURPOSE

Recent economic studies conducted by EPRI and others have identified gasification-combined-cycle power systems as major alternatives for generating electricity from coal in an environmentally acceptable manner. Of all of the different coal gasification systems investigated, advanced entrained flow gasifiers appear to offer the greatest economic potential for power generation. In general, these systems would involve a high degree of integration between the gasification units, the fuel cleanup systems and the combined-cycle components to achieve acceptably low heat rates. Complex integrated systems of this type have not yet been operated at any scale and therefore their dynamic response capabilities are largely unknown. Before these new power generating units can be reliably operated as part of larger electric utility systems, effective control strategies must be developed. Therefore, it is essential to understand their dynamic response characteristics and the interaction effects between the fuel process and power cycle components. For baseloaded plants to represent valuable additions to larger power systems, they must respond rapidly for short periods of time to small load demand changes to satisfy frequency regulation and tie line requirements, and respond gradually over long periods of time to follow morning load runup and evening load rundown. The response time associated with gasification and gas cleaning systems is longer than the response time of gas turbines; therefore, it is essential to determine how the fuel process will follow the integrated GCC power demand using alternative control strategies.

Two options for control of entrained gasification-combined-cycle (GCC) power plants operating in a typical power system environment were evaluated, as well as the effects of operating contingencies such as an equipment trip. Both control strategies, gasifier lead and gas turbine lead, have the ability to meet power system needs within the limits of equipment operating and safety constraints.

We have investigated the effects on system response characteristics of the storage capacity of the gasification plant, the gas cooling systems and the gas cleaning equipment, and the energy storage associated with the steam plant.

As part of the investigation, we have determined that the local control actions included in the study are sufficient to allow the entrained GCC plants to meet runup from minimum load, rundown to minimum load, and contingency conditions such as full trip of electrical load, and loss of a major module such as a gas turbine generator, etc.

SCOPE OF WORK AND METHODOLOGY

We generated mathematical model representations for each of the major components of the GCC plant, to determine the dynamic response characteristics and to make the required control analyses. The models were interconnected in much the same way as a physical plant and incorporated in a model of a large utility network to evaluate the GCC control characteristics.

Computer Program

The Fluor computer program used is a flexible executive program for dynamic simulation and control. It was used as a batch program for the control simulation. Over fifty subroutines, which contain algebraic and differential equations for such process units as adiabatic surge vessels, control valves, controllers, compressors, flash drums, condensing heat exchangers, turbines and so on, were used. Subroutines which were developed specifically for the control study were delivered to EPRI. The program is completely data driven, with over 3000 input data cards required for each study case.

First order Euler integration with automatic step size adjustment was used in this study. After all of the simulation units have been executed sequentially for one time step, time is incremented and the process is then repeated. The simulation was based on the ideal gas law and steam/water properties options. Eight gas components were used: hydrogen sulfide, H_2S; carbon dioxide, CO_2; hydrogen, H_2; nitrogen, N_2; methane, CH_4; water, H_2O; carbon monoxide, CO; and oxygen, O_2.

OXYGEN-BLOWN ENTRAINED GASIFICATION-COMBINED-CYCLE POWER PLANT INVESTIGATED

The following entrained GCC system was used as the basis for this study:

The design point used for this study was based on flowsheets generated by Fluor and described in EPRI AF-642 (Case EXTC - Slurry). Multiple train operation was employed. Plant capacity to be simulated was set by having two gas turbines at full load feeding two heat recovery steam generators and a single steam turbine.

An oxygen-blown single-stage entrained gasifier of the Texaco type fed with an Illinois #6 coal/water slurry is used. The baseline operating pressure for the gasifier was 612.9 psia. Crude gas from the gasifier was cooled in waste heat boilers against steam raising surface prior to H_2S removal in a low-temperature liquid absorption system. The clean fuel gas was reheated against gas turbine exhaust gas before being let down to gas turbine inlet pressure in an expansion turbine. The gas turbine modeled was an advanced technology machine having a nominal combustion outlet temperature of 2400°F (actually 2392°F at full load in the model).

The H_2S absorption system used for this study was the Selexol process licensed by Allied Chemical Company.

The conceptual gasifier and waste heat recovery scheme as modeled in the dynamic simulation is judged adequate to display the major interactions anticipated between the fuel gas processing plant and the combined-cycle power plant. However, it must be recognized that the configuration of equipment in this area is under study by Texaco and, therefore, subject to revision as the optimum design is developed.

MODELING

Dynamic models of the following subsystems have been generated for inclusion into the integrated gasification-combined-cycle plant:

Gasification

An oxygen-blown single-stage entrained gasifier of the Texaco type is modeled with a coal/water slurry feed system for operation in the range of 250 psig to 700 psig. This model predicts on a dynamic basis the crude gas composition, temperature and pressure as a function of coal slurry composition, coal slurry rate and slurry temperature, oxygen rate, oxygen temperature, and gasifier effluent flow rate. The model for the gasifier includes overall material and energy balance relationships coupled with wall heat transfer, mass and energy storage, and chemical heat of reaction effects. Although this level of detail is not truly representative of the fundamental kinetic reaction rates existing in the gasifier, it generally represents the dominant transient effects on effluent gas composition necessary to determine the significant system response characteristics. This model is capable of representing upset conditions down to a low level of capacity.

For this study, 100 percent carbon conversion has been assumed.

Slurry System

Modeling has been done to represent the sensible heat effects of the coal/water slurry feed system. We have assumed that the slurry feed system operates smoothly under all load conditions and responds instantaneously to all demand changes. Composition of the slurry has been held constant.

Similar assumptions have been made for the ash withdrawal system.

Gas Cooling

The essential features of the gas cleanup system includes gas cooling waste heat boilers followed by a water scrubbing system, a gas saturator, an H_2S absorber and a gas reheater.

Models for gas cooling and heating equipment as well as gas saturating devices have been developed. The relationships used to develop the models include mass and heat storage effects, heat transfer and phase change characteristics.

These models have the capability of determining clean fuel gas composition, temperature and pressure as well as steam generation from the waste heat boilers as a function of crude fuel gas composition temperature pressure and flow rate.

H_2S Removal

The H_2S absorption scheme is based on the Selexol process. Dynamic response characteristics of the Selexol absorber model developed include the effects of temperature, pressure, liquid-to-vapor ratio, feed rates and compositions, selectivity, tower flooding, and absorption efficiency of H_2S, CO_2 and H_2O. The effects of liquid holdup, vapor compressibility, heat transfer and the heat capacity of liquid and packing are included in the Selexol absorber dynamics.

Oxygen Plant Compressors

All compressors are driven with steam turbines. The compressors for the air separation plant are not modeled but algebraic equations are used to estimate the steam requirements of the compressor drivers as a function of air and oxygen throughput and steam conditions. The dynamics of the air separation plant are not simulated. The compressors are not permitted to turn down below 70 percent throughput unless they are simulating a trip.

Fuel Gas Expansion Turbine

This model has been developed using the fundamental thermodynamic relations governing the expansion process and applying representative hardware data to derive the necessary relationships. Control valves and line storage are included. Turbine efficiency has been assumed constant.

Combined-Cycle Power Plant

The gas turbine model includes gas valves, inlet guide vanes, dual fuel operation, inertia effects, the generator and normal controls, i.e., speed governor, exhaust temperature control, IGV control, gas valve action and appropriate control loop dynamics. The heat recovery steam generator model is based on mass and energy balances coupled with heat transfer, mass distribution and energy storage effects. The steam turbine model includes throttle and reheat pressure and temperature controls, speed/load controls, inertia effects and the generator.

Network

A model has been developed for a typical large power system consisting of two areas using a single frequency and based upon conventional power plants with coal or oil fired boilers with reheat steam turbines. Total GCC power represents 40 percent of the total capacity of Area I. This power system model generates system frequency dynamics, power interactions between operating areas with a single tie line, control dynamics and dynamic response characteristics of other connected units.

The Automatic Generation Control allocates the power demand required to return system frequency error to zero by sending signals to the participating units (including the GCC plant) based on tie line power control and system frequency deviation requirements. The power system model is capable of handling transients to represent short-term load variations, frequency regulation, tie line flow, unit commitment and daily load following.

To bring the GCC plant power contribution up to 2000 MW in Area I, we have connected 5.65 plants of the type described here to the network.

CONTROL STUDIES

The study was performed in three phases. First the GCC plant models were connected and local controllers turned to provide manual operation in "open-loop" control; that is, without the station controller and network models. After this, the network (with tuned controllers) was connected to the GCC plant via the station controller to investigate the "closed-loop" control. Since all controllers were previously tuned, the station controller was ready to use after selecting the ramp limits and steps associated with power error and pressure error. Finally, the GCC plant performance characteristics for "contingency operation" were investigated. All emergency trips studied were initiated at full load.

Open Loop

With the station controller turned off and the network disconnected from the GCC plant, the characteristics of the GCC plant were investigated. In all of these investigations the gas turbines are in pressure control mode, i.e., the plant pressure controller is regulating the fuel flow to the gas turbines to maintain plant pressure. Operating conditions are then established by manually changing the set points of the oxygen flow controllers at the gasifiers.

Closed Loop

The power system model was used to develop two control system strategies that could be employed such that the GCC plant will participate in satisfying power system needs. The control concepts investigated for the oxygen-blown gasifier are:

- Turbine Lead Mode. In this configuration, the combustion turbine fuel flow is controlled by power demand. This is typical of the control strategy practiced for liquid fuel-fired combined-cycle plants. Gasifier pressure is restored through the oxidant feed flow reacting to the plant pressure error by opening/closing the oxygen and coal slurry valves.

- Gasifier Lead Mode. This mode of control requires that oxidant and coal feed to the gasifier respond to changes in power demand. For this case, the fuel valve between the gasification plant and the gas turbine reacts to pressure control to maintain plant pressure.

Equipment constraints usually expressed as controller limit signals, i.e., gas turbine exhaust temperature, AGC, fuel plant pressure constraints, etc., are included in the models. The two different control configurations specified above have been evaluated for their ability to satisfy frequency regulation and tie line thermal backup requirements for normal load following duty as well as for power system upsets.

Contingency Operation

An essential part of this study was to identify the behavior of the fuel processing plant and its controllers under special operating conditions and emergency situations. We recognized that due to the approximate nature of some models, simulation could not be conducted over the complete electrical load range. At the very low end where temperature constraints of the steam turbine system dominate and restrict changes to less than 2° in steam temperature per minute, no simulation has been done. To include the effects of inlet guide vane movement on gas turbine power, we wanted to have a minimum load point where the guide vanes were closed. In the closed loop control runs the ramp and stepdown load changes were from full-speed/full-load (IGVs open) down 20 percent where the IGVs were not quite closed. For the ramp and stepup from minimum load, the IGVs were closed and remained closed. Therefore, a reasonable minimum load has been defined as follows:

- The gas turbines running, synchronized and loaded to 45 percent of their nominal full power with IGVs closed
- At this point, the HRSG and the fuel processing plant exchangers are providing sufficient steam to meet steam turbine and compressor drive requirements
- The steam turbine synchronized using all available steam to generate 42 percent of its nominal full power
- The gasifiers producing 60 percent of design fuel flow

Contingency Operation

The contingency operations selected for simulation are typical of major upsets which might occur in equipment in a real plant. They represent upsets in the major units which are known to cause major electrical power transients, but not necessarily the largest flow transients. For example, the turbine trips selected were generator trips where the turbine under its own controller reacts to be at full speed, no electrical load. Of course, this represents a major electrical transient, but not the larger flow transient of tripping the gas turbine (no flow). However, to maximize the electrical transient we have tripped from full load.

Unfortunately, when a trip occurs, many other events might take place (according to operator action or automatic controller logic), but it was not practical to simulate all the permutations and combinations of subsequent trips. Rather, we have generally chosen to minimize the number of subsequent events for two reasons:

- We wanted to have the model calculate what would happen if little action was taken so that flow, temperature and pressure data could be analyzed to determine if and when subsequent trips had to occur to protect other equipment.
- We wanted to generate results for "pure" events.

Accordingly, many units remain operating with little change, while the tripped unit changes variables directly affected by this equipment. We have indicated where subsequent events should occur. Occasionally, we violated this guideline to demonstrate some special feature of other units or because the plant had to have subsequent events occur, even in the model.

Contingency operating conditions investigated included:

- Loss of steam turbine electrical load
- Loss of one gas turbine electrical load
- Loss of two gas turbine electrical loads
- Loss of all electrical load
- Loss of one HRSG
- Loss of one train of oxygen and air compressors
- Loss of one gasifier

- Fuel gas back-pressure valve fails, forcing a fast fuel transfer to oil

Before highlighting the power results for all runs (open loop, closed loop and contingency operation), we will describe the plant, how it was modeled, what the major controls are, and how the model relates to the design basis, CASE EXTC - Slurry in AF-642.

Section 2

PLANT DESCRIPTION AND STATION CONTROLS

GENERAL

A plant for electric power generation based on single-stage, entrained-bed, oxygen-blown gasifiers of the Texaco type integrated with combined-cycle generating equipment, was developed and published as Case EXTC (Slurry Feed) in AF-642. This plant consumed 10,000 ST/day of Illinois No. 6 coal.

The main plant consisted of oxidant feed, gasification, gas cooling, acid gas removal units and combined-cycle power systems. The oxidant feed unit was in five parallel operating trains. The gasification unit consisted of five parallel operating trains and one spare train. The gas cooling and acid gas removal units were in three operating parallel trains. There were seven parallel gas turbine/heat recovery steam generator sets and a single steam turbine.

In addition to the main processing trains, the plant included necessary offsite, utility and environmental facilities. Coal receiving, storage, grinding and conveying was done in a single train to minimize space and operating labor requirements. Hydrogen sulfide removed from gasified coal was processed through sulfur recovery facilities which produce elemental sulfur. Other operating facilities in the plant are raw water treating, steam generation, cooling water, and effluent water treating. Process condensate generated is recycled back to the gasification unit. Support facilities to sustain an independent plant operation are provided as well.

<u>Table 2-1 shows the number of operating and spare sections in the original economics report, and also the number of trains simulated with its nominal scale factor</u>. In general, the main plant units are simulated, and the offsite, utility and environmental facilities are not simulated. The arrangement of the units simulated are shown in Figure 2-1. The control study unit scale factors were determined by starting with two full-sized gas turbine/HRSG units and matching other units to these gas turbines.

Table 2-1

MAJOR EQUIPMENT SECTIONS: CASE EXTC (SLURRY FEED)

Unit No.	Unit Name	Case EXTC Operating	Case EXTC Spare	Simulation Study Case EXTC Operating	Simulation Study Case EXTC Scale Factor
10	Coal Handling	1	0	N.S.	
11	Oxidant Feed	5	0	2	0.74
20	Wet Coal Grinding	2	0	N.S.	
20	Slurry Preparation	1	0	1	None
20	Gasification	5	1	2	0.74
20	Ash Handling	1	0	N.S.	
20	Particulate Scrubbing	5	1	2	0.74
21	Gas Cooling	3	0	1	0.88
22	Acid Gas Removal	3	0	1	0.88
23	Sulfur Recovery and Tail Gas Treating	2	1	N.S.	
30	Steam, BFW and Condensate System				
	. Condensate Collection and Deaeration	1	0	1	None
	. Water Treating	1	0	N.S.	
32	Cooling Water System	1	0	N.S.	
40	Effluent Water Treating	1	0	N.S.	
50	Gas Turbine/Generator	7	0	2	1.00
51	Heat Recovery Steam Generator	7	0	2	1.00
51	Steam Turbine/Generator	1	0	1	0.295

N.S. means Not Simulated


STEAM TURBINE
H.P.
I.P.
L.P.
ROTOR
INFO BUS
1 TO 46
TO HRSG SYSTEM
CONDENSER & HOT WELL
LEVEL CONTROL
LAG
MAKE-UP WATER
I.P.-L.P. BYPASS
STEAM CONDENSATE
FUEL GAS HEATER
CONTROLLER
STC
F 543, 643
F 532, 632
P 580, P584
CONDENSATE FM. O2 PLANT COMPRESSOR DRIVERS SECTION 15
CONDENSATE FM. O2 PLANT EVAPORATORS SECTION 15
BFW PUMP TURBINE COND. SECTION 4
COLD CONDENSATE TO PROCESS SECTION 10
STEAM FROM DEAERATOR SECTION 4
9/14/79 REVISED TO ELIMINATE CONFIDENTIAL TEXACO INFORMATION
DATE
REVISION DESCRIPTION
DWG. NO.
REFERENCE DRAWING
NOTICE: THIS DRAWING HAS NOT BEEN PUBLISHED AND IS THE SOLE PROPERTY OF FLUOR ENGINEERS AND CONSTRUCTORS, INC. AND IS LENT TO THE BORROWER FOR HIS CONFIDENTIAL USE ONLY; AND IN CONSIDERATION OF THE LOAN OF THIS DRAWING, THE BORROWER PROMISES AND AGREES TO RETURN IT UPON REQUEST AND AGREES THAT IT SHALL NOT BE REPRODUCED, COPIED, LENT OR OTHERWISE DISPOSED OF DIRECTLY OR INDIRECTLY, NOR USED FOR ANY PURPOSE OTHER THAN THAT FOR WHICH IT IS FURNISHED.
FLUOR
DRAWN BY L. ACEVEDO
CHECKED BY R. SIEBERT
RELEASE DATE 9/14/79
SUPERVISING ENGR S. SMELSER
CLIENT EPRI
OXYGEN CONTROL STUDY
SIMULATION DIAGRAM
BASIS: TWO GAS TURBINES FM. EXTC SEE AF642
SCALE NONE
DRAWING NUMBER 462204-SKETCH-1
REVISION 012
16
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3
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1

Total GCC plant power, as modeled:

Gas Turbine Power No. 1	113.1
Gas Turbine Power No. 2	113.1
Steam Turbine Power	127.4
	353.6 megawatts

This corresponds to a heat rate of 8806 Btu/kWh which is essentially the same as the heat rate published in Case EXTC.

The entire gas train from the oxygen plant to the flue gas exiting from the HRSGs was simulated. Fuel processing condensate (water) sumps and recycle streams were included to account for the sensible heat in the water streams. The steam flows and steam condensate were calculated to close the steam balance. Since the condensate polishing unit was not simulated, not all of the steam condensate returns to the hotwell. Therefore, the water flow to the hotwell includes demineralized water makeup as well as water recycled through the polishing unit.

The simulation includes the following local controllers not illustrated on the Block Diagram Showing Major Controls:

Oxygen Plant

- Header Pressure Control
  - Sets gaseous oxygen production
- Header Pressure Control
  - Pressure relief
- Evaporator Temperature Control
  - Sets steam flow to evaporator

Gasification

- Slurry Tank Level Control (Ideal)
  - Sets coal flow to maintain level in the slurry tank

Steam Generation and Particulate Removal

- HP Steam Drum Pressure Control
  - Maintains generator pressure to meet exchanger design requirements
- IP Steam Drum Pressure Control
  - Prevents excess steaming at low throughput
- MP Steam Drum Pressure Control
  - Keeps fuel gas in the IP exchanger above the dewpoint
- Steam Drum Level Controls (Ideal)
  - Sets constant level
- Particulate Scrubber Sump Level Control (Ideal)
  - Sets makeup water flow
- Particulate Scrubber Sump Blowdown Control (Ideal)
  - Sets blowdown proportional to fuel gas flow

Gas Cooling Unit

- LP Steam Drum Pressure Control
  - Prevents excess steaming
- Sump Level Controllers (Ideal)
  - Sets constant level
- Liquid/Vapor (L/V) Ratio Control at Ammonia Absorber (Ideal)
  - Sets liquid flow proportional to gas flow

Acid Gas Removal Unit

- Selexol Solvent L/V Control (Ideal)
  - Sets inlet liquid flow on linear schedule with gas flow

Miscellaneous Steam Generators and Consumers

- Flow Ratio Control (Ideal)
  - Sets some steam flows are proportional to fuel processing plant flows

Fuel Gas Expander

- Downstream Header Pressure Control
  - Maintains constant gas turbine inlet pressure

Heat Recovery Steam Generation

- HP Drum Level Control (Standard three element control)
  - Sets makeup water flow
- IP Drum Pressure Control
  - Prevents excess steaming rate
- Superheated Steam Temperature Control
  - Opens bypass around superheaters
- Reheated Steam Temperature Control
  - Opens bypass around reheaters
- BFW Split From HRSG Land 2 Economizers
  - Sets the BFW split proportional to available heat (temperature) in gas turbine exhaust

Steam Turbine Controller

- Water Flow Split Logic
  - Sets flow split of BFW from economizers to users
- Isolation Valve Logic for Superheaters and Reheaters
  - Closes valves when gas turbine exhaust is too cold
- Speed Control
  - Regulates throttle and intercept valves for a turbine generator
- HP Turbine Bypass Control
  - Opens trip bypass valve to prevent header overpressurization
- IP Turbine Bypass Control
  - Opens bypass to prevent header overpressurization

Gas Turbine Controller

- Speed Control
  - Sets fuel gas flow for a generator trip

- Fuel Transfer Logic
  - Permits operation on mixed fuels (oil and gas)
  - Permits transfer from oil to gas firing
  - Permits transfer from gas to oil
- Near Full Load Logic
  - Restricts fuel flow to prevent excessive turbine temperatures

Deaerator

- Level Control
  - Sets water flow
- Circulation Flow Control
  - Sets water circulation through fuel gas preheaters on a schedule with gas turbine exhaust temperature
- Pressure Control
  - Sets steam flow in to prevent low pressures
  - Sets steam flow out to prevent overpressurization

Condenser/Hotwell

- Level Control
  - Sets makeup water flow for losses in steam system

Miscellaneous

- Recirculating Fuel Processing Plant Water Temperature Control
  - Limits water temperature to prevent overpressurizing the atmospheric water tank
- Desuperheater Controls
  - Sets water flow
- Water Tank Level Control
  - Sets makeup flow for process water consumed in gasifier to make H_2 and lost with fuel in gas turbine

A detailed flow sheet, as developed for the simulation depicting the control stations modeled, is included in Volume II.

All controllers were sufficiently tuned to perform the control study, but the tuning parameters were not optimized. <u>The local controllers performed well during all transients</u>.

OXYGEN PLANT

<u>The oxidant feed system for Case EXTC has been reduced to two nominal 74 percent sized trains</u> from the original five parallel operating trains. Each train has one air compressor, one air separation plant and one oxygen compressor. Only the steam demand for compressor drivers is modeled.

Atmospheric air is compressed to 110 psig in a centrifugal machine. Heat of compression, which is rejected to air in an interstage air fan cooler, is not calculated. The compressed air is processed in an air separation unit which produces 98 percent oxygen.

The HP steam required by each air feed compressor is supplied by combination of a steam turbine and a fuel gas expander. The steam turbine driver is a condensing type machine designed for normal inlet conditions of 340 psig, 1000°F, with exhaust pressure at 2-1/2" Hg abs. The steam turbine is designed with excess capacity to provide response capabilities during turndown or upset conditions. Oxygen plant vendors indicate that 25 percent per hour ramp rates of gaseous oxygen production could be achieved with nominally constant oxygen concentration. We have used this rate and assumed constant composition.

Liquid oxygen storage is provided, with attendant cryogenic pumps and vaporizer. Storage is equivalent to approximately three days of rated capacity operation of a single train. The evaporator is modeled as two steam exchangers in series and has the capacity of one gaseous train. The equipment was sized and arranged to be able to vary liquid throughput from 20 to 100 percent at a rate of 10 percent per minute.

The air separation plant produces oxygen at 16.2 psig and 90°F. The oxygen is normally compressed up to 720 psia. The compression requirement is supplied by a condensing type steam turbine. The normal inlet steam condition is 340 psig, 1000°F with back pressure at 2-1/2" Hg abs.

GASIFICATION

Gasification for Case EXTC had six parallel trains, one a spare. We are simulating two trains of nominal 74 percent size.

The Texaco gasifier is a vertical cylindrical vessel. Coal slurry and oxygen combine at the gasifier burners.

The gasification section operates at an average pressure of 612.9 psig and temperatures in the range of 2300°F to 2600°F. The gasification temperature must be sufficiently above the ash flow point to ensure free-flowing molten slag. Part of the coal burns with oxygen to provide heat for the endothermic steam and CO_2 reactions with char. The coal slurry and oxygen react to form CO, CO_2, H_2 and a small amount of CH_4. For the simulation, all of the coal sulfur is converted to H_2S. Nitrogen in the coal transforms to free nitrogen. The ash melts to form slag. Ammonia (ND_3) and carbonyl sulfide (COS), which are normally formed in the gasifier, are not part of this study. Both compounds are present in such small amounts, that the overall control scheme can be developed without including them.

Most of the ash in the form of slag falls into a water quench at the bottom of the gasifier. The resultant ash slurry leaves the gasifier and enters the slag dewatering unit. Overflow from the slag dewatering unit is recycled to the coal slurry system.

STEAM GENERATION AND PARTICULATE REMOVAL

Raw hot gas from the gasifier is cooled in a steam generation unit, modeled as two nominal 74 percent sized trains, to a temperature well below the ash softening point. Our modeling effort does not include solids normally entrained in the crude gas. Hot boiler feedwater near the IP steam saturation temperature (467°F) is supplied to the HP and IP steam generators from the Heat Recovery Steam Generation (HRSG) units. Boiler feedwater is also supplied from the deaerator for MP steam production. High-pressure (HP) steam at 1520 psia, saturated intermediate-pressure (IP) steam at 460 psig and saturated medium-pressure (MP) steam at 114 psia, are produced in this unit. Each steam drum is on pressure control to isolate the process plant from the power block steam pressures.

After heat removal, the raw gas flows to the particulate scrubbers. Water from the ammonia absorber bottoms and hot process condensate from the gas cooling unit are used for gas scrubbing. The clean gases from the particulate scrubber flow to the gas cooling section.

GAS COOLING

Of the three parallel trains in the gas cooling section of EXTC, one nominal 88 percent sized train is modeled. Clean gasifier effluent from the particulate scrubbing section is cooled to approximately 101°F in a series of exchangers. Heat is recovered by the generation of saturated 65 psia steam. The effluent, after separation of condensate, is then cooled by exchanging heat against clean fuel gas from the acid gas removal section. The condensate produced in cooling is separated. Further gas cooling is obtained by heating cold condensate from the steam turbine condenser and the resultant process condensate is separated. Hot process condensate is pumped to the gasification unit.

The gas is further cooled with water to approximately 97°F in a trim cooler and flows to an ammonia absorber. Ammonia is normally removed by contacting the gas countercurrently with the water on the trays in this unit. Since this modeling effort does not include ammonia, the ammonia absorber is modeled as a water-gas contractor. Water flow into the absorber is proportional to the gas flow rate. The overhead gases from the absorber then flow to the acid gas absorber for H_2S removal. The net water from the bottom of the absorber is recycled to the particulate scrubber as cold process condensate.

ACID GAS REMOVAL

Of the three parallel acid gas removal trains of EXTC, one train of 88 percent size is needed, and only the absorber column is modeled, i.e., the regenerator and auxiliaries are not included.

Since the gasifier produces no COS, all coal sulfur is present as H_2S. The sulfur removal levels presented in this report do not reflect quantitative predictions of total sulfur removal. COS, normally, 10 percent of the sulfur in the gas, is less soluble than H_2S in Selexol. However, we feel that the qualitative results presented herein can be extrapolated to apply to total sulfur removal.

The acid gas removal system employs Allied Chemical Corporation's Selexol process for selective removal of hydrogen sulfide (H_2S). Hydrogen sulfide in the crude gas is absorbed in Selexol solvent in order to reduce sulfur in the treated gas to 1.0 pound sulfur dioxide (SO_2) equivalent per million Btu (HHV) coal charged to the plant.

The cooled gas flows through an acid gas absorber where it contacts Selexol solvent countercurrently over a packed bed. For the simulation, lean solvent at constant temperature and composition enters the absorber. The treated gas from the top of the absorber, after heat exchange with gasifier effluent in the upstream unit, flows to heat recovery steam generators for further heating.

Acid Gas Removal Equipment Not Simulated

The rich solvent from the bottom of the absorber would be let down to a flash drum. Most of the H_2S would be retained in the solvent because of its selective absorption in the Selexol solvent. The rich solution from the flash drum would then exchange heat with hot lean solution and flow to the top of the regenerator where the absorbed H_2S and CO_2 are stripped from the solution (estimated reboiler steam requirements are included in the control study steam balance). Hot regenerated (lean) solvent would be pumped back to absorber through the rich solution exchanger and a trim cooler. The cooled acid gas containing about 40 volume percent H_2S would flow from the regenerator to the sulfur recovery unit for conversion to sulfur.

Sulfur Recovery and Tail Gas Treating

There are two 50 percent parallel operating sulfur recovery trains in Case EXTC, each followed by a tail gas treating unit. These units are not in the control study, but their estimated BFW requirements and steam produced are included in the steam system balances.

GAS TURBINE GENERATORS AND GAS TURBINE CONTROLLERS

Of the seven gas turbines in Case EXTC, two full-sized turbines are modeled. Each gas turbine has its own HRSG.

The combustion turbine-generator is modeled for a combustor exhaust temperature of 2400°F at full load (not peak load). The model includes inlet guide vanes, cooling air system, compressor, combustor and combustor volume, turbine, gas fuel control valve and inlet nozzle, gas fuel isolation valve, liquid fuel valve, and generator (rotor when not connected to the line). Compressor performance data was scaled from compressor maps for machines already built and operated by Westinghouse.

Each gas turbine has its own control system including actuator dynamics, fuel transfer logic, near full load logic, IGV controls and fuel control from the low selected output of three parallel controllers:

- speed/load control
- plant pressure control
- temperature limit control

Most of the control features are images of standard Westinghouse controls. The plant pressure control feature has been added and the fuel transfer logic has been modified slightly to be able to operate the turbine with dual fuels (mixed fuel operation).

STEAM SYSTEM AND HRSGs

The fuel processing plant steam generation is integrated with the combined-cycle system. The steam system operates at four levels:

High-Pressure	-	1422 psia, 900°F (per throttle pressure schedule)
Intermediate-Pressure	-	342 psia, 1000°F (with interceptor valve wide open)
Medium-Pressure	-	114 psia
Low-Pressure	-	65 psia

High-pressure steam (HP) generation is carried out in heat recovery steam generators (HRSG) of gas turbines. Additional HP steam generation is obtained in the fuel processing plant gas cooling units. The saturated HP steam from the process units combines with the saturated steam produced in the HRSG HP evaporators and is superheated to 900°F in the HRSG superheaters. All the superheated HP steam is used to drive the single back pressure type HP end of the power turbine. The HP end of the turbine takes steam at 1422 psia, 900°F and exhausts at 389 psia.

Saturated intermediate-pressure (IP) steam is obtained from 460 psia generators located in the sulfur plant and gasification unit and also at 389 psia in the HRSGs. The saturated IP steam together with the exhaust steam from the HP turbine is superheated to 1000°F in the HRSGs' reheaters. The superheated IP steam at 342 psia, 1000°F is used both in the IP end of the power turbine and also in the condensing turbines in the oxygen plants. The IP end of the power turbine exhausts at 2-1/2 inches of Hg abs.

Steam Generators and Consumers (for Steam Balance)

The 114 psia steam generated in the gas cooling unit along with a small quantity of the desuperheated IP steam is supplied to the reboilers in the acid gas removal unit. The balance of the 114 psia steam is let down to the 65 psia level.

Additional 65 psia is supplied by steam generation in the fuel processing plant exchangers. Most of the total 65 psia steam is used in the condensing turbine driving the boiler feedwater pump. A small amount of steam is used for steam tracing and for heating in the sulfur pit. All of these steam users are included in the steam balance but not all their condensate returns to the hotwell.

Water from storage is transported to the hotwell as makeup.

Boiler Feedwater

Boiler feedwater (BFW) from the deaerator is pumped through boiler feedwater pumps to the HRSGs, process HP steam generators and process IP steam generators. Only the high-pressure pump with steam driver has been modeled. Essentially, all the plant BFW flows through this pump. The boiler feedwater pump drivers use 65 psia saturated steam.

BFW to the HRSGs is first heated to the IP steam saturation temperature (459°F) in economizers. Part of the BFW is withdrawn downstream of the economizers and supplied to the process IP steam generators, HRSG's IP evaporators and the desuperheating station. The balance of the BFW is heated to the HP steam saturation temperature (598°F) in the HRSG's economizers. A portion of the hot high-pressure BFW is used to preheat fuel gas. The balance of the high-pressure BFW flows to the HP steam generators located in gasification unit and HRSGs where saturated high-pressure steam is generated.

The 50 psig steam generators are supplied boiler feedwater by separate pumps (not modeled) directly from the deaerator.

Hotwell and Deaerator

The vacuum condensate from all the turbines in the plant is combined in the hotwell. After being heated in the gas cooling unit, hot BFW flows to the deaerator on level control. The deaerator operates at 28 psia and provides 10 minute storage. Most of the deaerating steam is generated in the HRSGs' LP steam evaporators. Steam for pressure control is available from the IP steam header. Excess steam, if any, is dumped to the hotwell.

HRSG Models

The heat recovery steam generators are each modeled as individual components that are connected together. The steam superheater, reheater and fuel gas heater, at the lower section of the HRSG, each receive only a fraction of the gas turbine exhaust flow. The other exchangers receive all the flue gas flow. In sequence, according to decreasing flue gas temperature, they are: HP evaporator, economizer No. 2, IP evaporator, economizer No. 1 and the LP evaporator for deaeration steam. Each exchanger is modeled with metal mass and water mass as part of the dynamic.

All flue gas heat transfer is through finned tubing. Heat transfer coefficients are defined for both sides of the tubing, except for evaporators where the boiling side coefficient is assumed infinite.

Evaporators are modeled with their associated drums to provide water flow transients. The HP drum is modeled with a standard three element controller. Since the duty of the IP drum is quite small, it was modeled with ideal level control. The deaerator serves as the drum for the LP evaporators.

The pressure in the HP drum is determined by piping pressure drop to the HP turbine inlet pressure. Pressure control has been added to the IP drum to prevent excess steaming at low gas turbine loads (in restrospect, this control feature is not required).

Superheat temperature control is implemented by passing HP saturated steam around both superheaters through a common bypass line. Reheat temperature control is similarly achieved with a single bypass line around both reheaters.

To implement steam turbine generator trips, superheated steam is let down through a turbine bypass valve on header pressure control through a desuperheater to the IP header. Similarly, the reheated steam is let down through a second turbine bypass valve on header pressure control through a desuperheater to the steam turbine condenser/hotwell.

Fuel Gas Heaters In The HRSG

Fuel gas produced in the fuel processing plant at 546.6 psia and 310°F is first heated to 568°F by heat exchange against hot boiler feedwater extracted from the outlet of economizer No. 1. The cooled feedwater flows back to the deaerator. The fuel gas is further heated to 961°F in a coil provided in the reheater section of HRSG.

STEAM TURBINE AND STEAM TURBINE CONTROLLER

One steam turbine and generator unit at 29.5 percent size is modeled. The complete steam turbine model includes the high-pressure turbine with a throttle valve, and the intermediate-pressure turbine with an interceptor valve. The model was based on Westinghouse turbines for the full EXTC case steam flows. Once efficiencies were established, the flows were scaled to the nominal 2/7 control study size.

"Sliding pressure" operation for the steam turbine has been selected on the basis of experience with the Westinghouse PACE 260 combined-cycle plants. The throttle valve pressure set point is scheduled to vary linearly with steam flow above a minimum pressure of 300 psia. The interceptor valve is kept wide open (except for a turbine trip). When supply pressures are significantly above the steam turbine operating pressures, the steam turbine bypass valves open to let down steam to the condenser hotwell.

The steam turbine is in "follow" mode: The throttle valve regulates inlet pressure on a schedule with flow, the interceptor valve is wide open, and the turbine consumes all available steam.

The steam turbine controller is provided with speed/load control which sets steam flow on speed control in the event of a turbine trip.

FUEL GAS EXPANDER

The hot fuel gas from the HRSG is subsequently expanded from 509 psia to 325 psia in an expander to supply a portion of the oxygen plant air compressors' power. The balance of the air compressors' power is provided by condensing steam turbines which take reheat steam.

CONTROLS

General

As depicted in the Gasification Combined Cycle Plant Block Diagram Showing Major Controls (page 2-5), the station controller receives input from the network model as "power demand" and input from the fuel processing plant as "plant pressure" and sends output signals to the oxygen and slurry flow controllers at the gasifiers and speed/load signals to the gas turbine controllers. Each gas turbine controller receives the output of a plant pressure controller as direct input at all times. This plant pressure controller output feeds a gain-only controller in the gas turbine which is active in the pressure mode, in mixed fuel operation and in overriding other gas turbine controllers in the event of a severe depressurizing of the process plant.

Two modes of "closed-loop" station control have been investigated depending on where the power imbalance is directed and where the pressure imbalance is directed.

- When the power error is sent to the gas turbines, we have TURBINE LEAD and the pressure error is sent to the gasifier flow controllers.

- When the power error is sent to the gasifiers, we have GASIFIER LEAD and the plant pressure controller acts on the gas turbines.

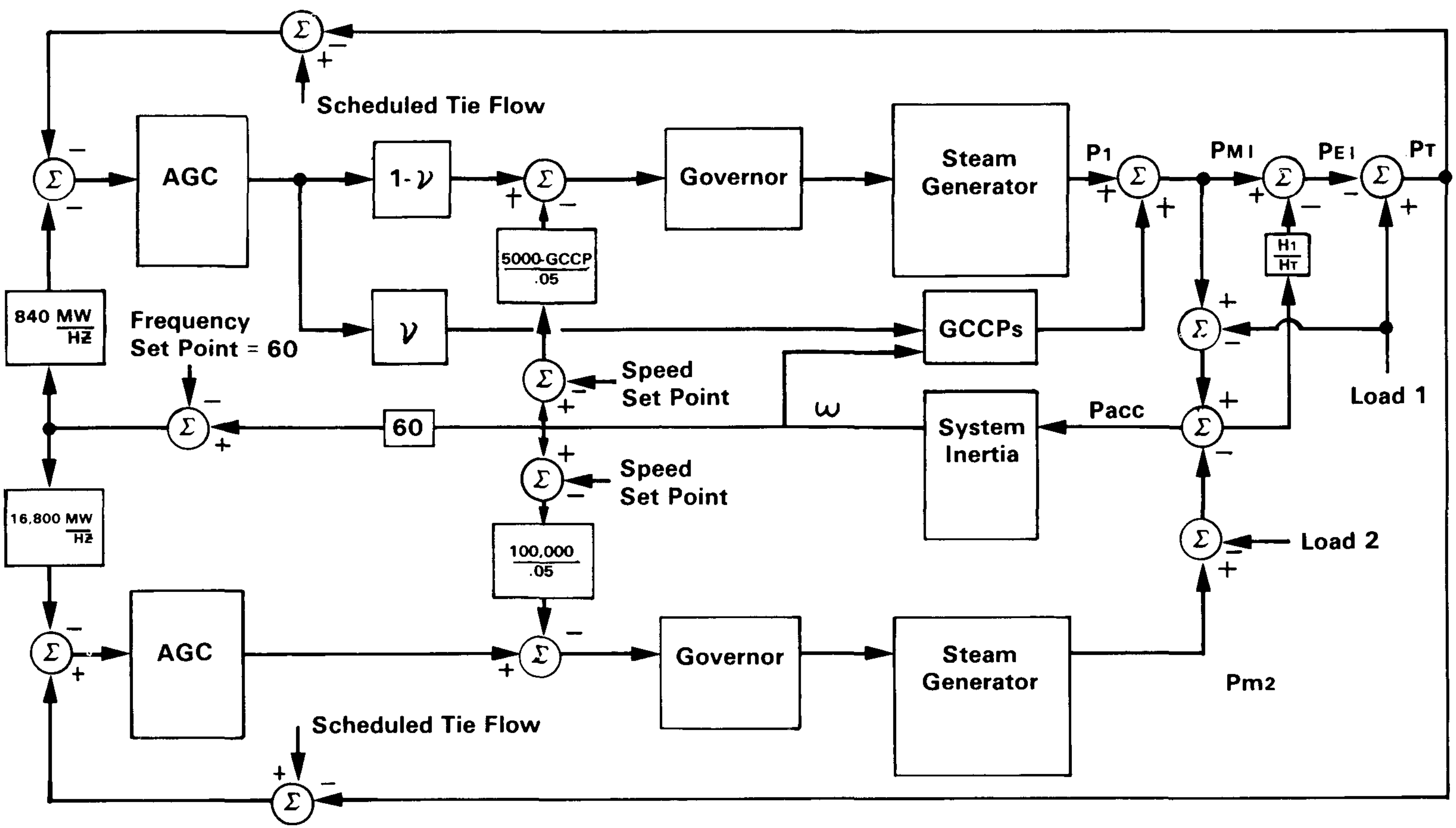
The control study objective was to demonstrate feasible control schemes, not to finalize controls nor to optimize the control settings. For closed-loop controls as presented here, the step and ramp limit settings in the station controller were not varied to demonstrate maximum GCC plant response. For gasifier lead, the station control limits must be selected to match oxygen plant dynamic response limits. Our settings for gasifier lead are compatible with the oxygen supply system developed for this study. For turbine lead the station controller settings selected resulted in responses near the low end of gas turbine response capability, near the normal ramp rate for Westinghouse gas turbine control. Although faster response would be permitted up to the gas turbine limits we have chosen to show normal (slow) responses in this study. We wanted to demonstrate GCC plant response while not severly stressing the gas turbine hardware.

In particular, we have not addressed the control aspects if the GCC plant response were severely limited by oxygen supply dynamics. For station control with limited oxygen supply dynamics, the station controller should be modified to further restrict the step and ramp limits. This may require coordinated control, rather than simply gasifier lead or turbine lead.

Some studies were done "open-loop"; the station controller was not operating. For these runs, the oxygen flow set point at the gasifiers was manually controlled and the plant pressure error was sent to the gas turbine. To perform the contingency runs, the plant was operated open-loop.

Network

The network model block diagram is depicted in Figure 2-2, where the GCC plant block diagram is collapsed to a single box (GCC plants). The network, a two-area power system model, is used to simulate power demand for the GCC plants during load changes. The capacity of Area I is 5000 MW and it represents a local utility composed of GCC plants and modern reheat turbine generation. Area I includes all load and generation that is closely connected to the GCC plants electrically. The capacity of Area II is 100,000 MW and it represents neighboring utilities which are lumped together in a strongly connected pool. Area II accounts for all



ELECTRICAL NETWORK

Figure 2-2. Electrical Network

other generation and load far removed from the local Area I, and is modeled as modern reheat turbine generation.

The major components of the power system are each represented by a transfer function, except the GCC plants which are represented by the detailed models contained in the GCC plant. The transfer functions can be represented in varying degrees of complexity. For this particular application, the emphasis is on the GCC plant rather than on the power system dynamics and a great amount of detail for the power system is not warranted.

The electric power produced in the generators and the GCC plants is used to supply load, transmit power to the other area, or accelerate the system. The rotary inertia of the system is accelerated by the imbalance between power generated and the power consumed or transmitted. Feedback to the GCC plants and the governors is provided from two sources: the speed regulator and the automatic generation control (AGC). The AGC acts to maintain the tie-line flow at its schedule value and to have each area pick up load changes. In Area I, the change in AGC is proportioned to the GCC plants and the steam generators. As depicted, this network model transmits a power demand signal and a normalized speed signal to the GCC plant. The GCC plant returns a signal representing power generated.

A total of 5.65 GCC plants as described here are connected to Area I. They represent almost 2000 MW of generated power at full load (nonpeak operation) in the 5.65 GCC plants.

Turbine Lead

As shown in Figure 2-3, the combustion turbines respond to net power demand by changing the speed/load·reference in response to the station controller's "raise and lower" logic signals (LSCON) at a rate (LFAST) set by the station controller. These logic signals act to bring each turbine's power generation to within ±1 MW of the power being demanded. The signal for each gas turbine is developed to accommodate parallel loading or sequential loading of the gas turbine and acts only on those turbines designated by the plant operator as in station control.

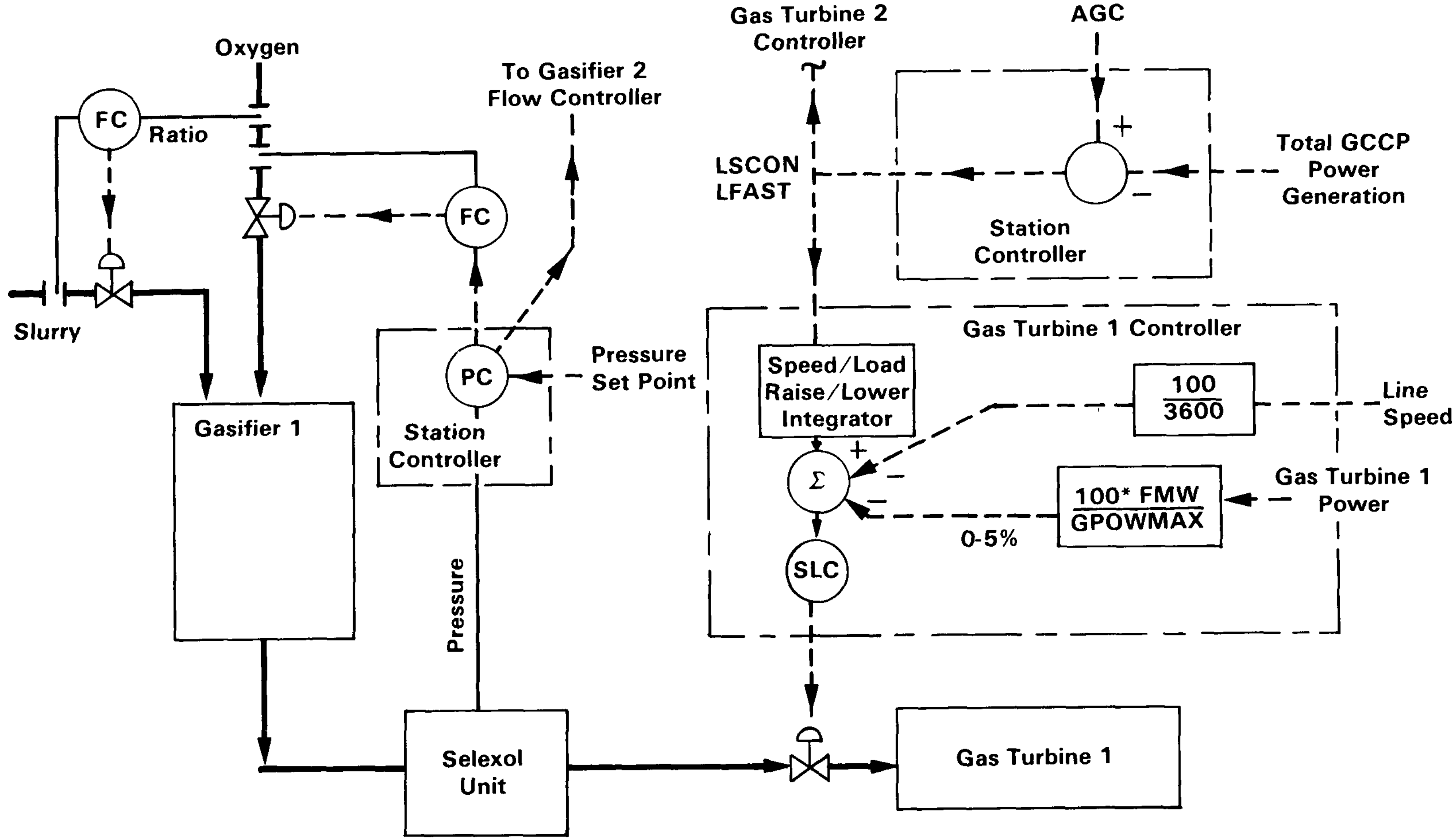
A step and ramp limited pressure controller has been added to the station controller to regulate plant pressure by changing the set points of the flow controllers at the gasifiers. The pressure error is limited to 0.5 percent. The step is limited to a gain of 0.5 and the ramp limit is 10 percent per minute.

Since the output of the plant pressure controller is not limited, we do not connect its output to the gasifier flow controllers. By using the limited controller in the station controller, we have avoided depressurizing the oxygen plant header.

Gasifier Lead

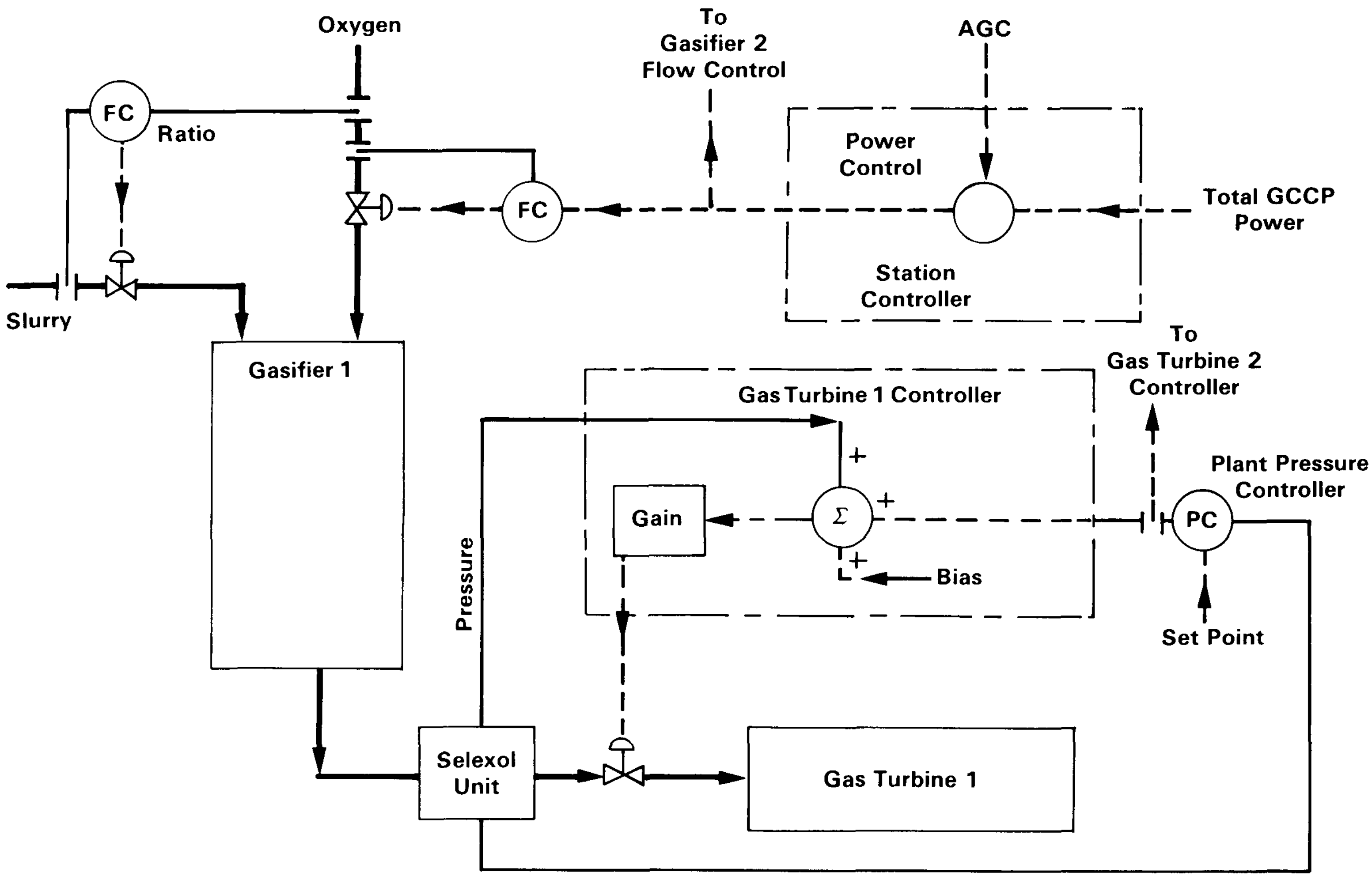
As shown in Figure 2-4, the net power demand passes through a step and ramp limiter to provide set point changes for the oxygen flow controllers at the gasifiers. The power error is limited to 0.5 percent. The step is limited to 0.5 percent gain and the ramp limit is 5 percent per minute.

In this station control mode, each gas turbine is placed in pressure control mode. This activates the gain-only pressure controller in the gas turbine to regulate fuel flow to the turbine and, thereby, to regulate plant pressure. When the pressure control mode is selected, the bias signal becomes negative and equal to the plant pressure set point. As a result the plant pressure controller output directly drives the gas turbine fuel valve to regulate plant pressure.



TURBINE LEAD: POWER ERROR TO GAS TURBINES, PRESSURE ERROR TO GASIFIERS

Figure 2-3. Turbine Lead Station Control



GASIFIER LEAD: POWER ERROR TO GASIFIERS, PRESSURE ERROR TO GAS TURBINES

Figure 2-4. Gasifier Lead Station Control

Section 3

RESULTS

Included in this section are plots of GCC plant power produced as calculated in the computer simulations for twenty-three different cases. These variables are presented to give the reader a perspective of the power dynamics inherent in the gasification-combined-cycle power plant. Each computer run is summarized briefly below the plot to explain the objective and major features of the output. Additional details on each case are provided in Volume II.

COMPUTER SIMULATIONS

The results are organized into three groups:

- open-loop manual operation
- closed-loop station control
- contingency operation

Open Loop

With the station controller turned off and the network disconnected from the GCC plant, the characteristics of the GCC plant were investigated. In all of these investigations the gas turbines are in pressure control mode, i.e., the plant pressure controller is regulating the fuel flow to the gas turbines to maintain plant pressure. Operating conditions are then established by manually changing the set points of the oxygen flow controllers at the gasifiers.

The first run presented shows the transition in the gas turbine, steam turbine and total plant powers as they approach the steady-state values near full electrical load at the design point. Grouped together, the next five plots demonstrate control of the GCC plant and its capabilities to come down to minimum load, to operate at minimum load, and to come up from minimum load. Increasing and decreasing load runs alternately demonstrate plant response to a series of rapid intermittent step as well as slow ramp changes. They show how well the entrained gasification-combined-cycle plant can respond to large quick changes and how smoothly the plant responds to morning "runup" and evening "rundown."

Closed-Loop Control

Following immediately are the eight closed-loop control runs which indicate how well the gasification-combined-cycle plant responds to electrical demand: four figures in the gasifier-lead mode and four figures in the gas turbine-lead mode. These eight plots are from the only simulation runs which included the network and the coordinating controller connecting the network to the gasification-combined-cycle plant.

In the simulations involving the network, the output from 5.65 GCC plants as modeled represents approximately 2000 MW (capacity) of a 4000 MW utility area (Area I). The remaining 2000 MW is modeled with the characteristics of conventional fossil-fired steam plants.

For the two control modes, Turbine Lead and Gasifier Lead, the same four load changes were made in the network model. Two runs were made at full FCC load: a 20 percent decrease in Area I load ramped down at 4 percent per minute, and a 20 percent step decrease in load. Two additional runs were made at minimum GCC operating load: a 20 percent increase in Area I load ramped up at 4 percent per minute, and a 20 percent step increase in load.

Contingency Operation

Eight contingency or emergency operation power plots are presented, one each for: loss of one gasifier, oxygen plant single train trip, trip of one gas turbine electrical load, trip of two gas turbine electrical loads, trip of steam turbine electrical load, loss of all electrical load, loss of one Heat Recovery Steam Generator (HRSG), and loss of one gas turbine gas fuel valve where the gas turbine is rapidly transferred to oil firing. In general, the eight contingency runs demonstrate that all the local controllers maintain all sections of the fuel processing plant in operation during the severe dynamics associated with the loss of some equipment. One additional plot, steady state with one gas turbine on oil, was included to provide data showing how the 2400°F turbine/HRSG system operates on oil compared to gas. For the contingency runs, little or no corrective action was taken to change the operating points of the GCC plant; that is, the excess fuel gas was flared. In a real plant, the operating levels might be altered by automatic computer control and/or operator decision.

The power variables plotted are arranged from the top down, as follows:

- Power set point (or benchmark power at full speed full load for steady-state and contingency runs), megawatts
- Total plant power generated
- Total gas turbine power
- Steam turbine power

Note that in some figures, the plot of total plant power generated coincides exactly with the plot of power demanded.

Gasifier Effluent Composition and Temperature

The gasifier effluent composition was essentially constant for all the simulations, even though the gasifier throughputs varied significantly (40 percent) and pressure changed as well (<10 percent). See Figure 3-1. Temperature of the oxygen and slurry streams and gasifier exit temperature vary slightly, but with the ideal ratio controller (that is with no lag) composition does not change. Separate subsystem studies indicate that gasifier temperatures might change on the order of 100 degrees for an abrupt change of 60 percent in the flow set point if the slurry flow lags (or leads) the oxygen flow by 1 second. However, for the gradual flow changes in closed-loop control, the gasifier composition and temperature will hardly change if the ratio control is designed for a lag of less than 1 second.

Pressure Control Point for Plant Pressure Control

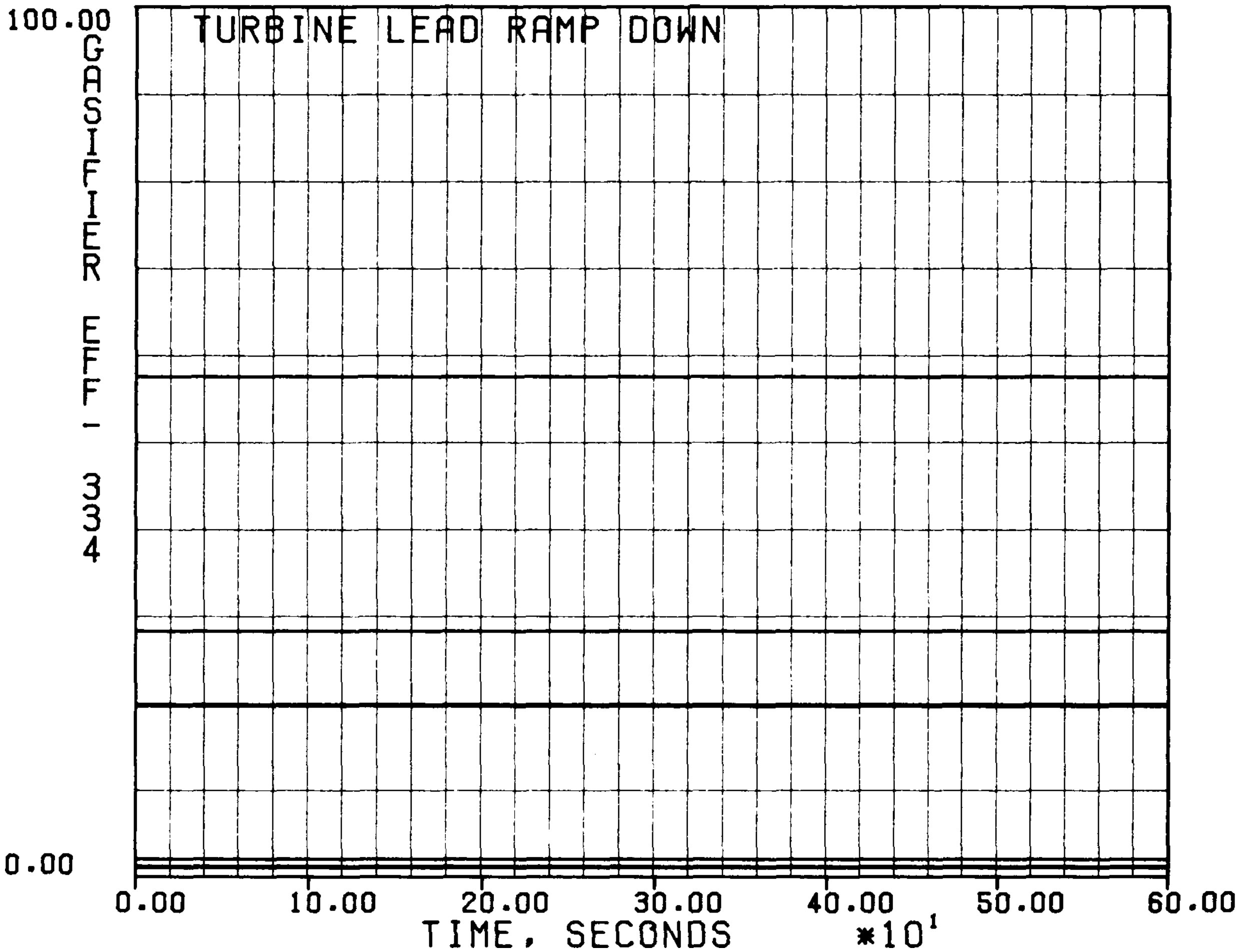
The plant pressure control point was selected to be just downstream of the Selexol absorber to minimize pressure changes at the Selexol column as gas flow varies.

The plant pressure profile for two plant percentage flow rates is as follows:

Steady-State Pressure Profile Versus Percent Design Flow Rate

	Pressure, psia				
Percent Flow	Gasifier	Selexol Outlet	Expander Inlet	Gas Turbine Fuel	Combustor Outlet
100%	612.9	546.6	509.1	324.7	235.6
60%	567.7	546.6	534.0	324.7	164.2
Change	-45.2	0.0	+24.9	0.0	-71.4

As can be seen from the profile, the gasifier pressure decreases 45 psi with flow decreasing 40 percent below design, while the pressure at the expander inlet has increased 25 psi. However, the Selexol column pressure has remained constant on pressure control. This arrangement minimizes the pressure excursions at the Selexol unit during load following and helps to maintain the percent sulfur removals achieved in this study.



Components From Top CO, H_2, CO_2, H_2O, N_2, CH_4, H_2S
CH_4 Curve Touches H_2S Curve

Figure 3-1. Gasifier Effluent Cumulative Compositions (Percent)

OPEN LOOP

BENCHMARK

The benchmark run to steady state included all models in the GCC power plant except the network and station controller which would connect power demand from the network into local set points for the GCC plant. To determine the heat and material balance for the GCC plant, the gasifier oxygen flows were set at the design point and the slurry fed on ideal ratio control proportional to the oxygen. The clean fuel gas produced was consumed by the gas turbines at a rate governed by a pressure control loop set to maintain plant pressure constant, at a point just downstream from the Selexol absorber.

Prior to this run, stable operation of the gas turbines under pressure control was not achievable. Even when trying to line the plant out at steady flow, the gas turbine fuel valves would cycle, causing turbine power to vary between zero and ninety percent load in about twenty second cycles. The control instability was eliminated by increasing the pressure drop for the fuel control valves above that specified in the EXTC study by 50 psi.

The net heat rate for GCC power plant has been estimated from the variables at the end of this run. The heat rate is 8806 Btu/kWh.

This compares well with the 8813 Btu/kWh published in AF-642 Case EXTC.

Gas Turbine Power		113.1 MW
		113.1
Steam Turbine Power		127.4
	Gross Power	353.6 MW

Steam conditions and flows were reasonably close to the design values.

	This Study	CASE EXTC
HP Steam Pressure, psia	1422.3	1464.7
HP Steam Temperature, °F	900	900
HP Steam Flow, lb moles/s	14.8	15.1 (2/7 EXTC)
IP Steam Pressure, psia	342.3	400
IP Steam Temperature, °F	1000	1000
IP Steam Flow, lb moles/s	10.3	11.3 (2/7 EXTC)

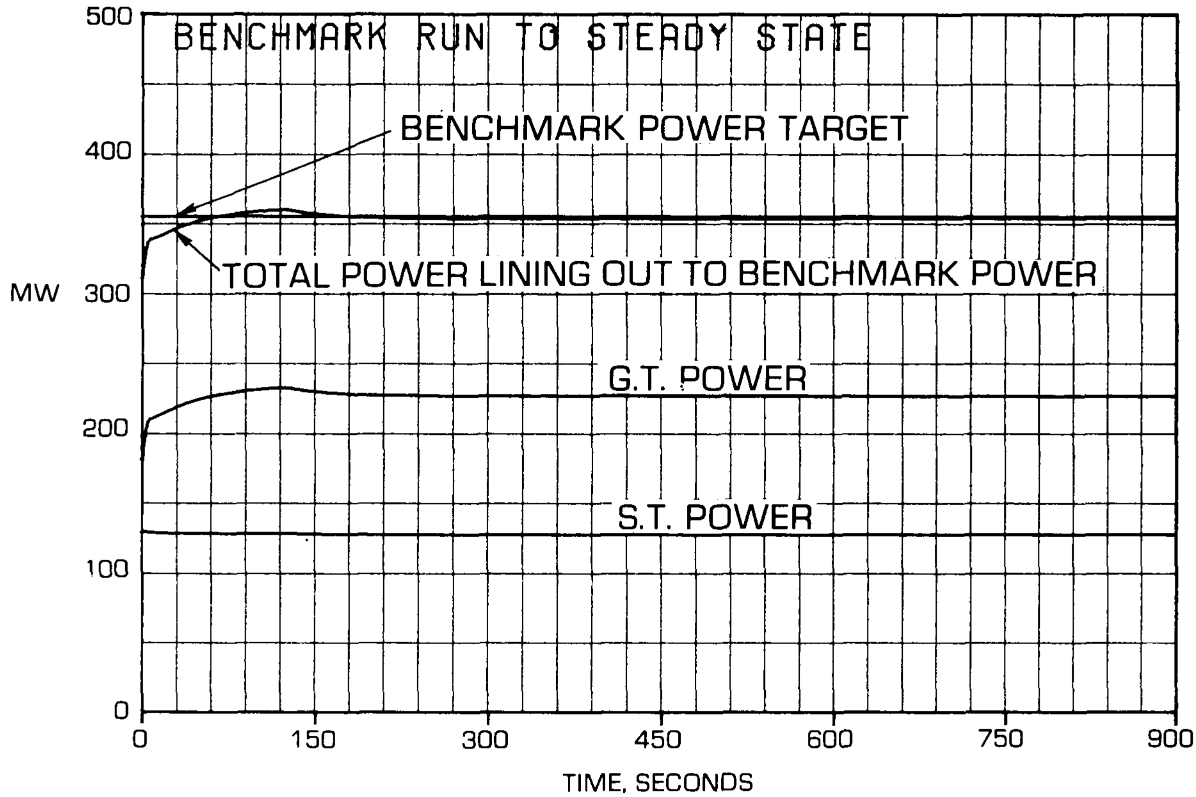


Figure 3-2. Benchmark Run to Steady State at the Design Point

RUNDOWN AT 10 PERCENT PER MINUTE IN FOUR STEPS

This run simulates the capability of the GCC power plant to accommodate rather large decreases in output with all local controllers tracking the change. Starting with the steady-state data generated by the benchmark run, the gasifier oxygen flow set point was ramped down in four steps. Each ramp represented a 10 percent change in flow in one minute with a one minute pause between ramps. The first ramp was initiated at 10 seconds and the last completed at 430 seconds.

During the 40 percent decrease in fuel gas flow, the gas turbine inlet guide vanes closed which reduced the air flow and the gas turbine compressor discharge pressure. The combustor temperature dropped over 350°F but the exhaust temperature decreased less than 100°F. Gas turbine power decreased nearly in unison with the flow changes at the gasifier, i.e., with approximately a 10 second lag. Gas turbine power dropped almost 55 percent for a 40 percent decrease in gas flow.

As a result of reduced gas turbine exhaust temperature, the steam reheat temperature dropped 100° below its nominal 1000°F control point as the temperature control valve closed. Process steam generation decreased just over 40 percent following the ramp steps after a short lag. In the sliding pressure steam turbine control system, both HP and IP header pressures decreased with steam flow. HP steam pressure decreased to 980 psia and IP pressure to about 150 psia. Net steam power decreased to about 66 MW, or about 52 percent of design.

The local control loops maintained control of the fuel processing plant during the rapid change forced by decreasing gas production 40 percent. All plant variables varied smoothly as expected. Power demand changes of this magnitude can be handled with the controls as used in this study.

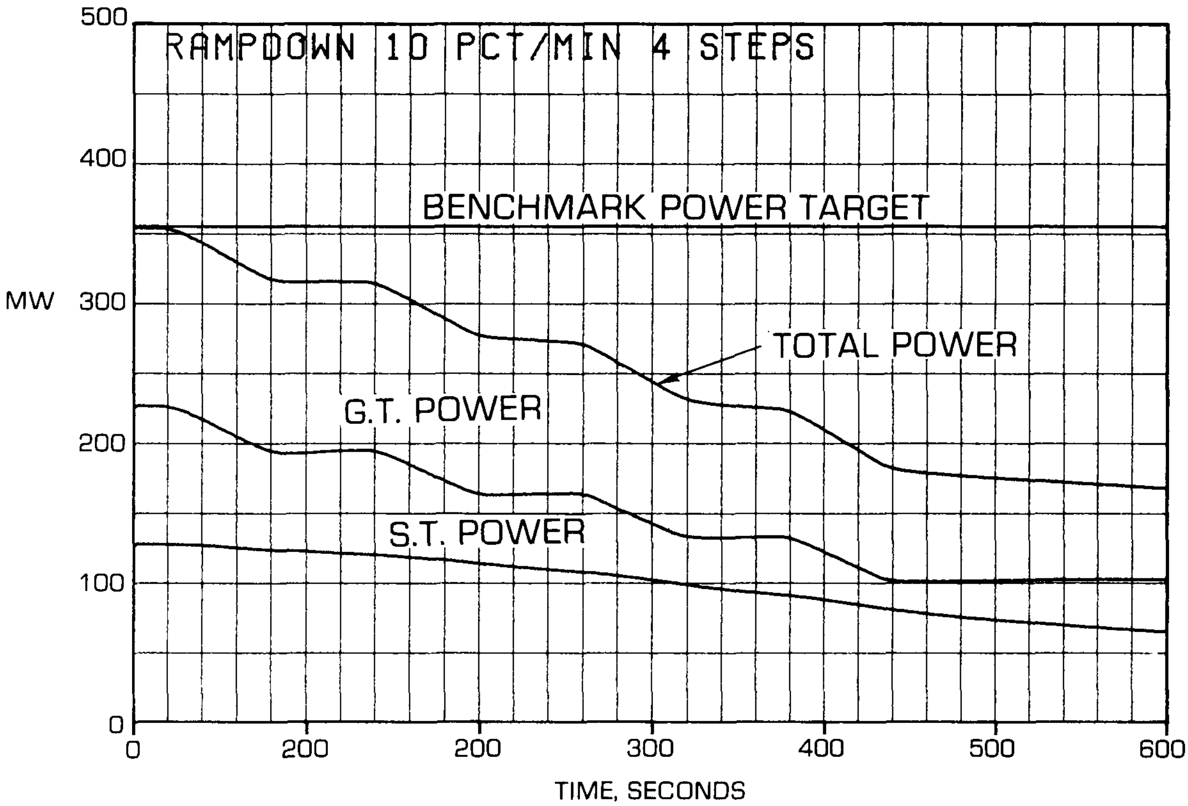


Figure 3-3. Rundown at 10 Percent Per Minute in Four Steps

RUNDOWN AT 2 PERCENT PER MINUTE

The rundown at 2 percent per minute run shows that the plant can easily follow continuous load decreases typical of daily load following. The range of the ramp is the same as that of the four step ramp, a 40 percent decrease in flow at the gasifier.

Starting with the benchmark steady-state data, the gasifier oxygen flow set point was decreased at 2 percent per minute for 20 minutes. The rundown started at 10 seconds. Oxygen flow and slurry flow followed the ramp closely. The pressure at the gasifier decreased smoothly along the ramp with the gasifier effluent temperature remaining virtually constant. The effluent gas composition was constant.

The decrease in oxygen demand caused the liquid oxygen evaporator to quickly reach minimum throughput and the gaseous oxygen production decreased continuously at the maximum rate. With only 60 percent of the gas flowing through the exchanger trains, process fuel gas temperatures had decreased, reflecting tighter pinch points. During this slow continuous ramp the plant pressure control maintained constant plant pressure within 1 psi at the Selexol absorber as the flow through the absorber gradually decreased.

While the plant pressure controller decreased the gas flow to the gas turbines to maintain constant plant pressure, the local gas turbine controller maintaining the gas turbine exhaust temperature closed the inlet guide vanes in about 525 seconds, thereby decreasing the compressor air flow, the compressor discharge pressure and the discharge temperature. The gas turbine power decreased almost linearly at 2.7 percent per minute.

The temperature control bypass on the superheat steam temperature remains partially open holding the superheat temperature. The reheat temperature control valve closes completely indicating that reheat steam temperature cannot be maintained; however, the temperature of the reheat steam is down less than 20°F from design.

HP steam make from the HRSG decreases about 20 percent while process HP steam decreases more than 40 percent. Pressures in the HP steam header have decreased about 36 percent and 61 percent in the IP steam header.

During the entire run, the gas turbines have operated effectively and remained on pressure control throughout.

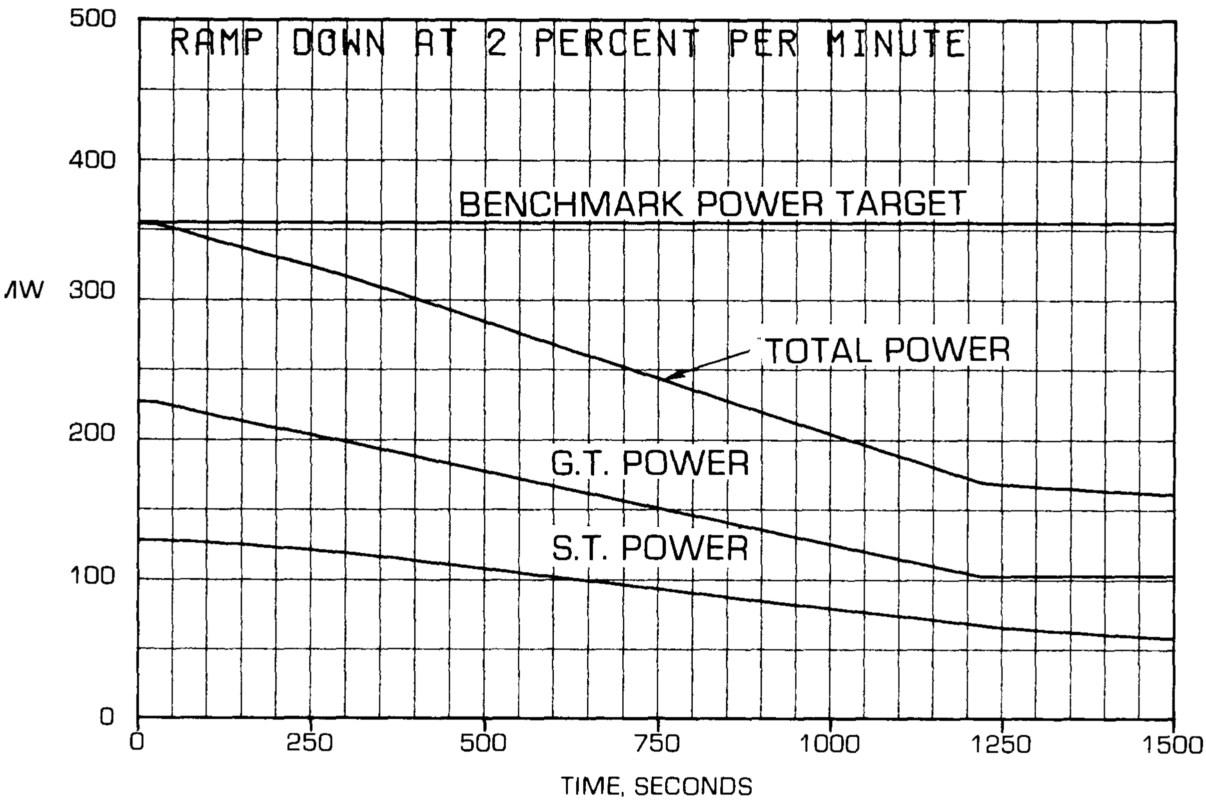


Figure 3-4. Rundown at 2 Percent Per Minute

STEADY STATE AT MINIMUM LOAD

Steady state at minimum load was obtained by continuing the computer simulation for 15 minutes after the rundown at 2 percent per minute. The purpose was to permit variables to reach new steady values prior to studying the ability of the GCC plant to respond to increases in power demand. Like the previous benchmark run, the network and station controller are not simulated.

To line out the plant at the new conditions, the oxygen plant gaseous flow was set at the minimum for two trains at the start of the run; the oxygen production is set low to simulate minimum load.

The gas turbine power is very steady. Nonetheless, the HRSG temperatures require most of the time simulated to line out at new values. The slow transition of temperatures in the HRSG primarily reflects the large amount of metal and water mass in the finned tubed exchangers. The time constant for the economizers, evaporators, reheaters, superheaters and gas heaters appears to be on the order of 200 seconds. The final HP steam pressure at minimum load is 850 psia and the IP steam is near 120 psia.

At minimum load, the net heat rate can be estimated from the variables at the end of the run. The heat rate at minimum load is 12,855 Btu/kWh, compared to 8806 Btu/kWh at the design point.

		% of design
Gas Turbine Power No. 1	51.3 MW	45.3
Gas Turbine Power No. 2	51.3	45.3
Steam Turbine Power	53.3 MW	41.8
Gross Power	155.9 MW	44.1

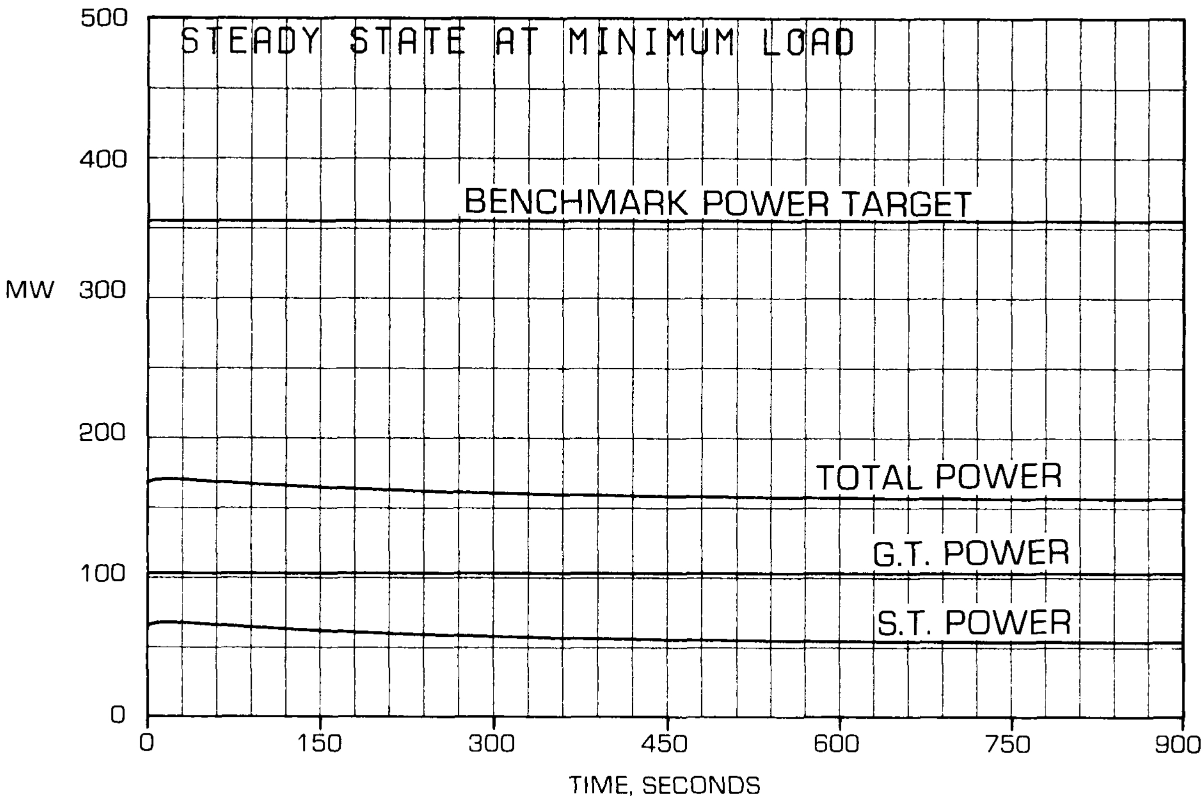


Figure 3-5. Steady State at Minimum Load

RUNUP AT 10 PERCENT PER MINUTE IN FOUR STEPS

As in the earlier step-wise rundown run, this run simulates the capability of the GCC plant to accommodate rather large increases in output with all local controllers tracking the change. Starting with the steady-state run at minimum load, the gasifier oxygen flow set point was ramped up in four steps. Each ramp represented a 10 percent change in oxygen flow occurring in one minute with a one minute pause between steps. The first ramp was initiated at 10 seconds and the last completed at 430 seconds.

Unlike the rundown run, the four step runup run was not quite as smooth in response. The oxygen flow followed the first three steps with no difficulty but was not able to follow the fourth ramp smoothly. The liquid oxygen evaporator flow rate tended to increase at maximum rate longer than the ramp and then decrease rather than hold steady. Accordingly, oxygen header pressure dropped which temporarily limited the oxygen flow to the gasifier slightly below the desired flow until the header recovered pressure.

As load increased with increasing gas flow, the inlet guide vanes at the turbine reopened. Air compressor flow increased, and the temperature and pressure at the compressor discharge increased. The combustion temperature increased 350°F back to the design temperature of 2400°F, and the exhaust temperature returned to 1142°F. The gas turbine power increased in four steps, the last step being as irregular as the oxygen flow to the gasifier. This behavior indicates how well the gas turbine follows the gasifier performance, and the importance of the rate of oxygen supply to the GCC plant.

Very early in the run, at about 50 seconds, the temperature control loop on the reheat steam opens and reheat steam temperature control is restored. HRSG HP steam make begins to increase at 350 seconds but has not yet reached steady production rates at 600 seconds, whereas process HP steam production has reached full production. Steam header pressures are continuing to rise with increasing steam flows to the steam turbine. The sluggishness of the HRSG steam generation system is evident in the plot of steam turbine power where steam power is still increasing three minutes after the final step has occurred.

Runup at 10 percent per minute in four steps has demonstrated that the GCC plant local controllers can handle extremely large demands for increased load.

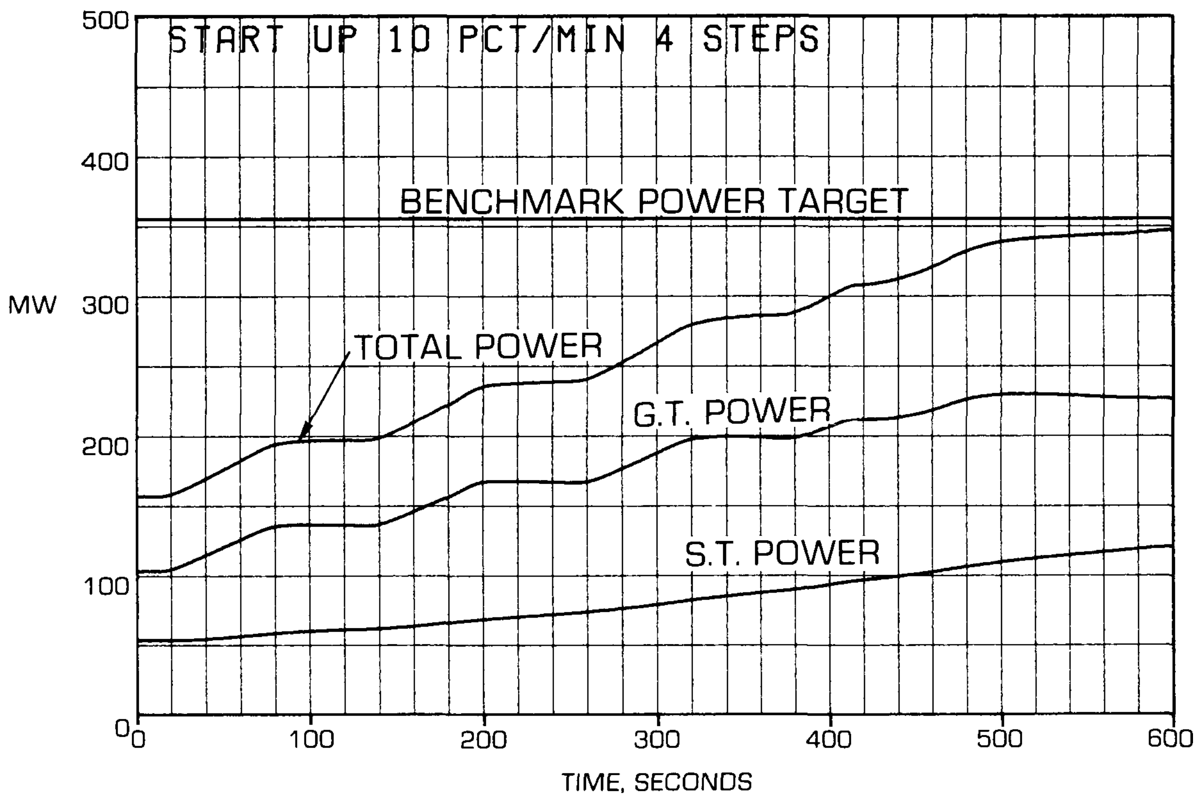


Figure 3-6. Runup at 10 Percent Per Minute in Four Steps

RUNUP AT 2 PERCENT PER MINUTE

To simulate the capability of the plant to follow daily load requirements it is sufficient to demonstrate that sustained load increases of 2 percent per minute can be met. Accordingly, we have increased gas production from 60 percent to 100 percent at 2 percent per minute for 20 minutes and the GCC plant has responded quite smoothly.

Starting from the steady state at minimum load, the oxygen flow set point at both gasifiers was ramped up at 2 percent per minute. Slurry flow and oxygen flow increased quite uniformly. During this flow increase, the gasifier pressure increased linearly from about 570 psia to 612 psia, while the reactor temperature remained essentially constant. The composition of the effluent from the gasifier was constant.

As oxygen demand increased, the gaseous production increased but the main portion of increased oxygen demand was supplied by the liquid evaporation system. If the gaseous oxygen production could respond faster than the 25 percent per hour rate assumed for this study, then it might be possible to meet daily load following without use of the liquid evaporation system.

At about 4 minutes into the 20 minute ramp, gas flow had increased to the point where the exhaust temperature control loop instigated the opening of the inlet guide vanes at the gas turbine. By the end of the 18th minute the guide vanes were all the way open. As the guide vanes opened, the compressor air flow increased and the discharge pressure increased. However, the exhaust temperature did not increase monotonically. The exhaust temperature increased until the IGVs started to move, then decreased with time until the IGVs were all the way open, then continued to increase until the gas flow ramp was complete.

Total HRSG heat recovery increases during the ramp, and continues to increase after the gas ramp finishes. Average temperatures of the flue gas in the HRSG rise, but the HRSG exhaust temperature only increases a few degrees which indicates that most of the increased sensible heat is recovered. Process steam generation follows increased gas flow quite closely. Throughout the increased production, the superheated and reheated steam temperatures are relatively constant. However, steam pressures increase quite substantially: the HP steam from 849 psia to 1450 psia and the IP steam from 119 psia to 371 psia.

Total power and steam power increase uniformly during the gas flow ramp.

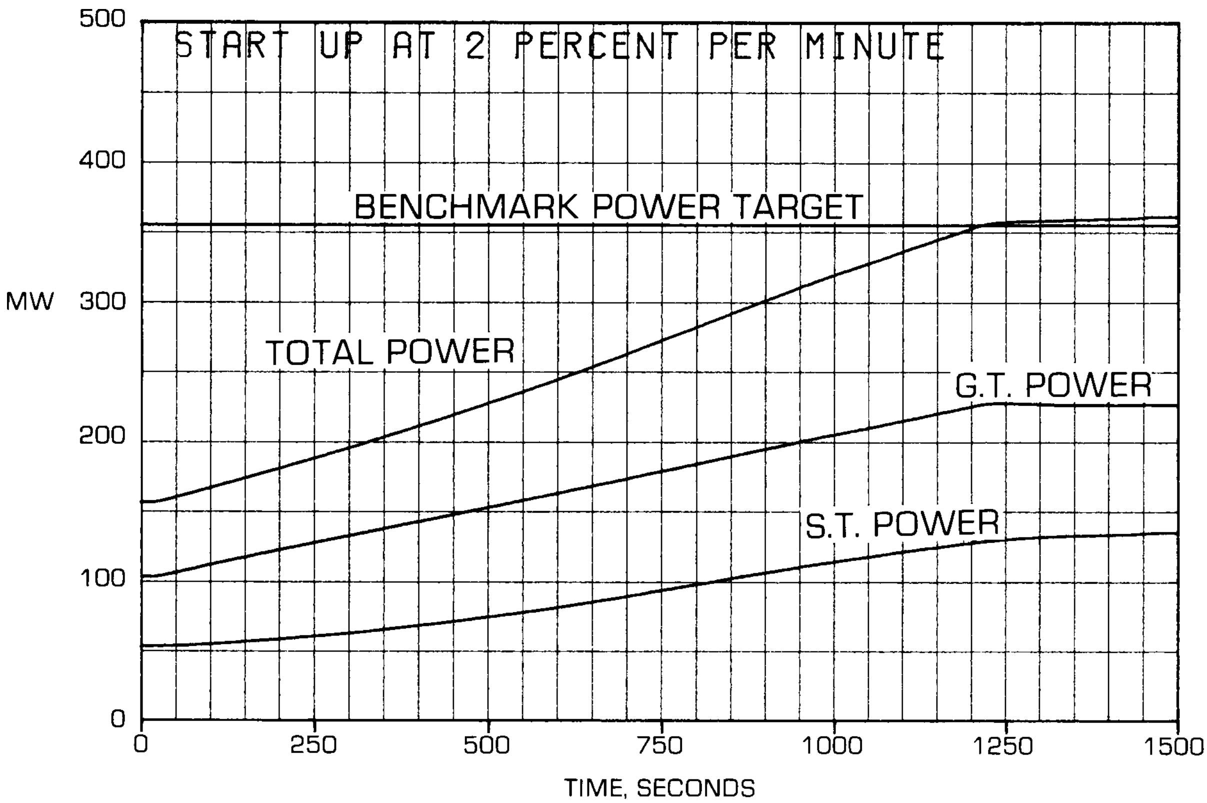


Figure 3-7. Runup at 2 Percent Per Minute

C L O S E D   L O O P

GASIFIER LEAD RAMPDOWN

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at full load. The power generation from 5.65 GCC power plants, as modeled, is connected to the network. Therefore, the total power input to the electrical network system from the GCC power plants is almost 2000 MW. The power demand for Area I is 4000 MW. Of this, just over 2000 MW is generated by conventional fossil-fired steam plants. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80 GW (load is also 80 GW) and it is modeled with the characteristics of conventional fossil-fired steam plants. The tie-line flow is scheduled at 0 MW.

The load in Area I is ramped from 4000 MW to 3200 MW in 300 seconds. This upset corresponds to a 4 percent per minute load decrease for 5 minutes, and requires approximately 70 MW power decrease from each GCC plant. The upset starts at 15 seconds and stops at 315 seconds.

A 20 percent ramp at 4 percent per minute causes a variation of 0.024 cps in line frequency (or a frequency change of 0.04 percent). The tie-line flow slowly increases from a scheduled value of 0 MW to 232 MW during the period of load variation. Once the load approaches its new value, the tie-line power flow is reduced to its scheduled value of 0 MW in 300 seconds.

The area generation controller changes the power set point for the GCC plant, and a master PI controller changes the gasifier flow set points accordingly. As shown, the GCC plant closely meets the demand which is requested by the Area I generation controller. The maximum variation between power demand and power generation is approximately 1.4 MW, or about 2 percent of the 70 MW change.

The steam turbine response lags approximately 150 seconds behind gas turbine exhaust gas temperature response.

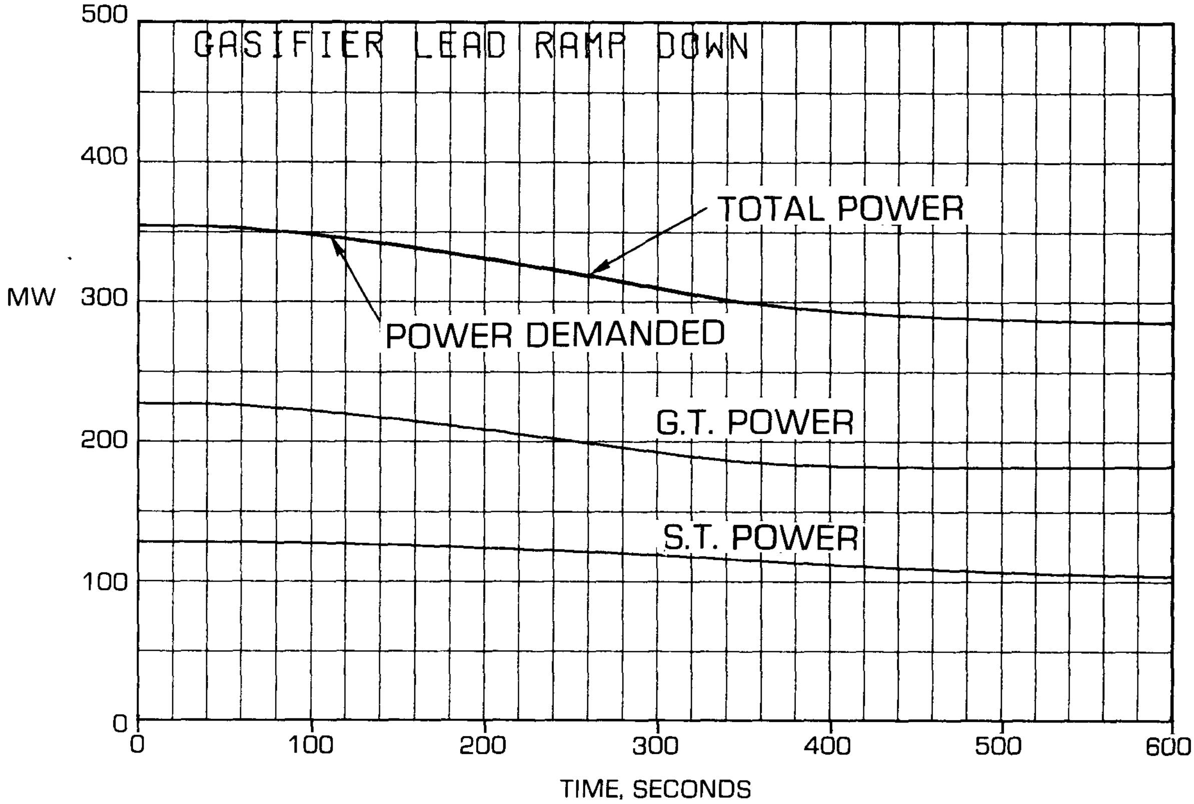


Figure 3-8. Gasifier Lead Rampdown Control Run

GASIFIER LEAD STEPDOWN

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at full load. The power generation from 5.65 GCC power plants, as modeled, is connected to the network. Therefore, the total power input to the electrical network system from the GCC power plant is almost 2000 MW. The power demand for Area I is 4000 MW. Of this, 2000 MW is generated by conventional fossil-fired steam plants. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80 GW (load is also 80 GW).

The load in Area I is changed from 4000 MW to 3200 MW instantaneously. This upset corresponds to a 20 percent load change in Area I and will require approximately 70 MW power decrease from each GCC power plant. The upset is introduced at 15 seconds.

A 20 percent step change in power causes a maximum variation of 0.108 cps in line frequency (or change of frequency of 0.18 percent). The change in load of Area I is quickly met by a 761 MW step change in the tie-line flow to Area II. After the power plants in Area I respond to the change in their set points which are imposed by the Area I generation controller, the tie-line flow decreases to its scheduled value of 0 MW in approximately 300 seconds.

The area generation controller changes the power set point for GCC plant, and a master PI controller changes the gasifier flow set points accordingly. As shown, the GCC power plant meets the demand which is requested by the Area I generation controller. The maximum variation between power demand and power generation is approximately 16 MW, or about 23 percent of the 70 MW change.

The gas turbine units of the GCC power plant respond quickly to the load variation. In approximately 200 seconds, the total power generation of the gas turbines reaches its minimum value of 175 MW. The slow decrease of steam turbine power generation results in gas turbine power generation increasing from its minimum value; at time 500 seconds the plant is almost at its new steady-state condition.

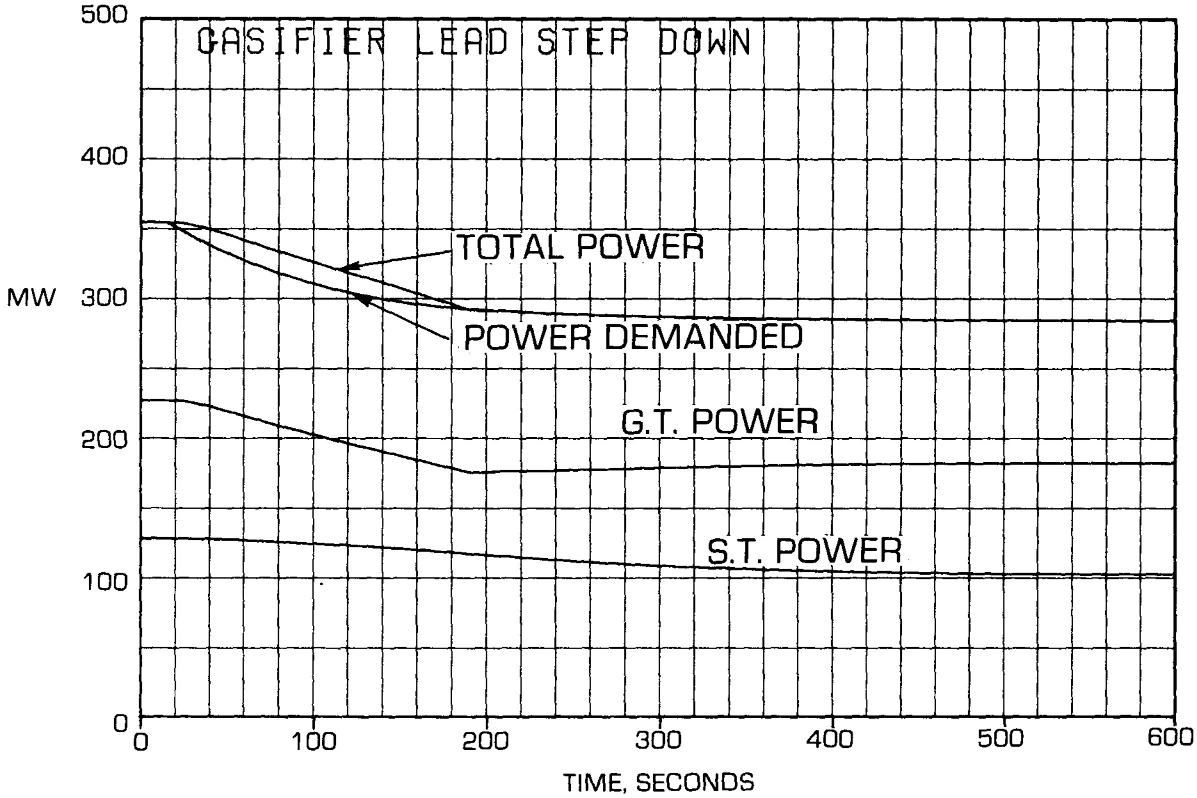


Figure 3-9. Gasifier Lead Stepdown Control Run

GASIFIER LEAD RAMPUP

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at minimum load (102.7 MW from two gas turbines, and 53.3 MW from the steam turbine). The power generation from 5.65 GCC power plants, as modeled, is connected to the network. Therefore, the total power input to the network system from the GCC power plant is 882.2 MW.

The power demand for Area I is 1764.2 MW. Of this, 882.0 MW is generated by conventional fossil-fired steam plants. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80 GW (load is also 80 GW). The tie-line flow is scheduled at 0 MW.

The load in Area I is ramped from 1764.2 MW to 2115 in 300 seconds. This upset corresponds to a 4 percent per minute load increase for 5 minutes, and requires approximately 31 MW more power from each GCC plant. The load change starts at 15 seconds and ends at 315 seconds.

A 20 percent ramp at 4 percent per minute causes a small variation of 0.012 cps in line frequency (or change of frequency of 0.02 percent). The change in load of Area I is partially met by the tie-line flow from Area II. The tie-line flow slowly increases from a scheduled value of 0 MW to 102 MW during the period of load variation. Once the load approaches its new value, the tie-line power flow is reduced to its scheduled value of 0 MW in 200 seconds.

The area generation controller changes the power set point for the GCC plant, and a master PI controller changes the gasifier flow set points accordingly. As shown, the GCC plant closely meets the demand which is requested by Area I generation controller. The maximum variation between power demand and power generation was approximately 0.6 MW, or about 2 percent of the 31 MW change.

The steam turbine power generation response lags by approximately 150 seconds behind gas turbine exhaust temperature response.

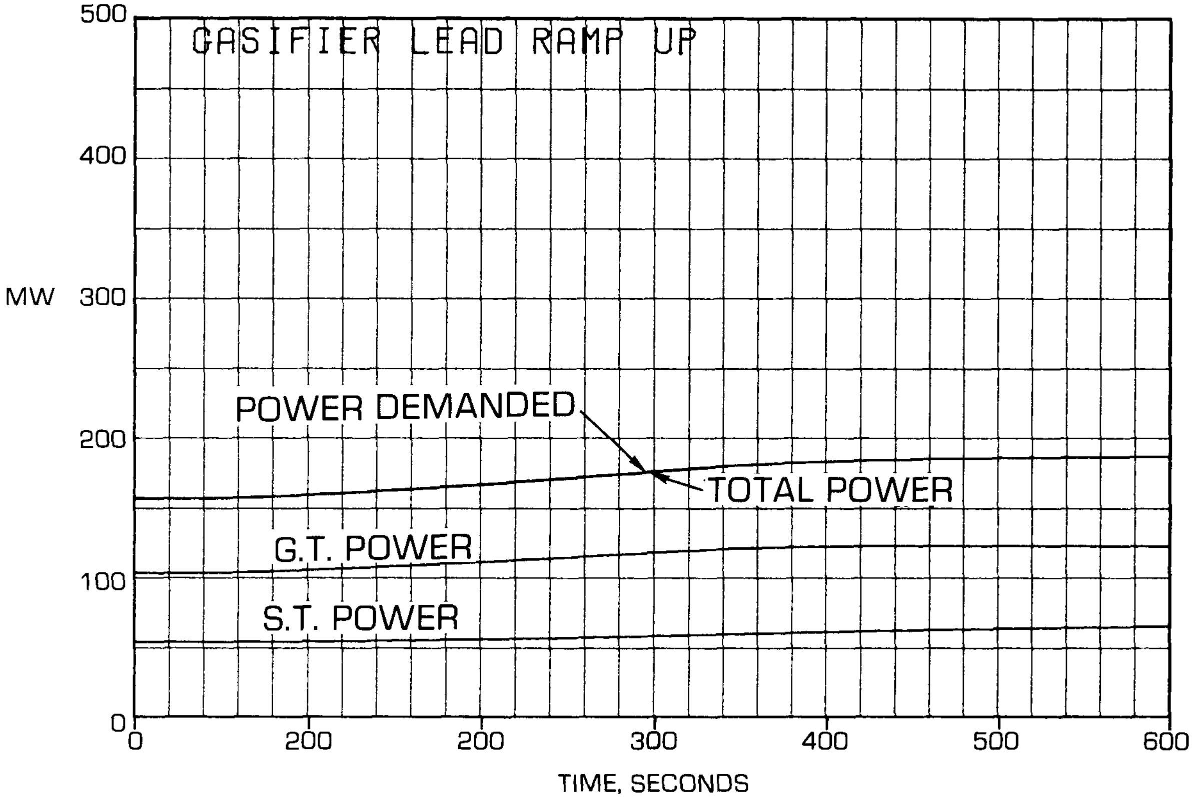


Figure 3-10. Gasifier Lead Rampup Control Run

GASIFIER LEAD STEPUP

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at minimum load which corresponds to 156.0 total MW power generation. The power generation from 5.65 GCC power plants, as modeled, is connected to the network. Therefore, the total power input to the network system from the GCC power plant is 882.2 MW.

The power demand for Area I is 1764.2 MW. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80,000 MW (load is also 80 GW). The tie-line flow is scheduled at 0 MW.

The load in Area I is changed from 1764.2 MW to 2115 MW instantaneously. This upset corresponds to a 20 percent load change in Area I and will require approximately 31 MW power from each GCC plant. The upset is introduced at 15 seconds.

<u>A 20 percent step change in power causes a maximum variation of 0.048 cps in line frequency</u> (or change of frequency of 0.08 percent). The change in load of Area I is quickly met by a 334 MW step change in the tie-line flow from Area II. After the power plants in Area I respond to the set point changes imposed by the Area I generation controller, <u>the tie-line flow decreases to its scheduled value of 0 MW in approximately 350 seconds</u>.

The area generation controller changes the power set point for the GCC plant, and a master PI controller changes the gasifier flow set points accordingly. As shown, <u>the GCC power plant meets the demand which is requested by the Area I controller</u>. The maximum variation between power demand and power generation is approximately 3 MW, or about 10 percent of the 31 MW change for a period of 30 seconds.

The gas turbine units of the GCC power plant respond quickly to the load variation. In approximately 240 seconds, the total power generation of the gas turbines reaches its maximum value of 123 MW. The slow increase of steam turbine power generation results in the gas turbine power generation decrease from its maximum value and at time 500 seconds the plant is almost at its new steady-state condition.

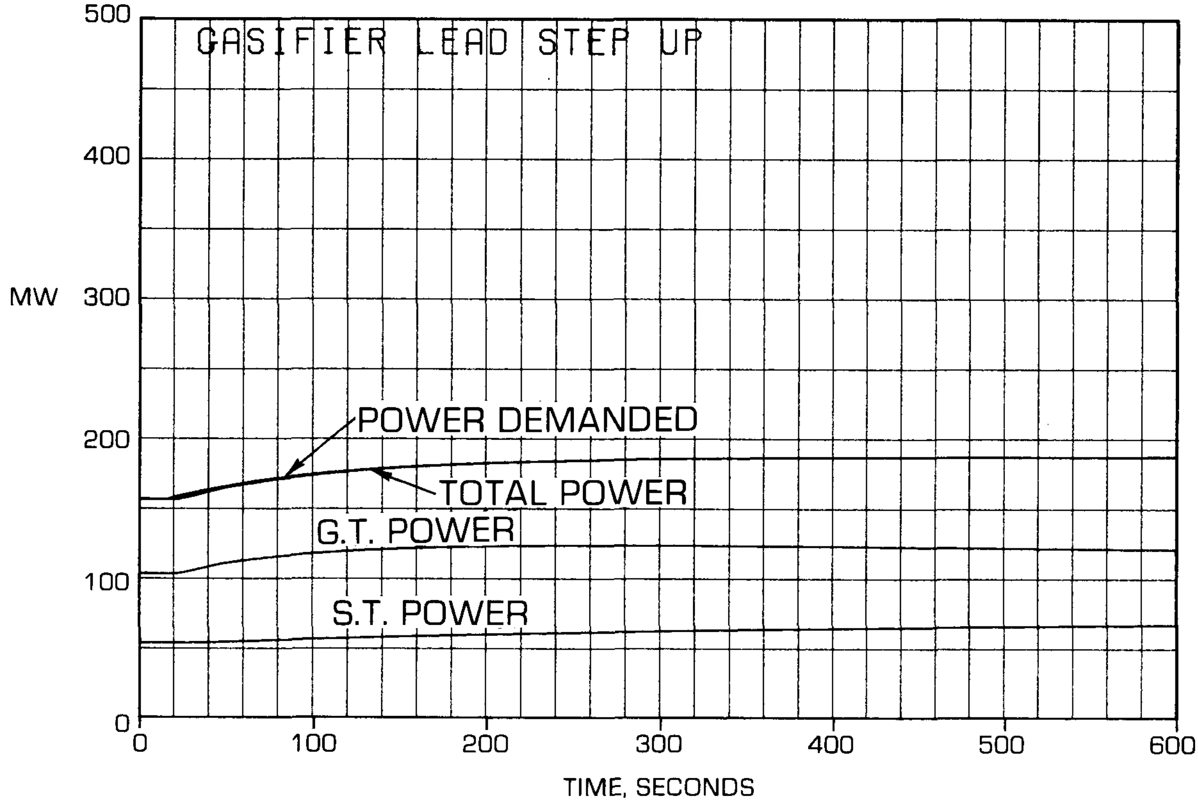


Figure 3-11. Gasifier Lead Stepup Control Run

TURBINE LEAD RAMPDOWN

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at 353.6 total MW power generation. The total power input to the electrical network system from the GCC power plant is at 1998.1 MW. The power generation from 5.65 GCC power plants, as modeled, is connected to the network.

The power demand for Area I is 4000 MW. Of this, 2000 MW is generated by conventional fossil-fired steam plants. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80 GW (load is also 80 GW) and it is modeled with the characteristics of conventional fossil-fired steam plants. The tie-line flow is scheduled at 0 MW.

The load in Area I is ramped from 4000 MW to 3200 MW in 300 seconds. This upset corresponds to a 4 percent per minute load decrease for 5 minutes, and requires approximately 70 MW power decrease from the GCC plant. The upset starts at 15 seconds and stops at 315 seconds.

A 20 percent load change at 4 percent per minute causes a small variation of 0.024 cps in line frequency (or change of frequency of 0.04 percent). The tie-line power flow is slowly increased from a scheduled value of 0 MW to 231 MW during the period of load variation. Once the load approaches its new steady-state value, the tie-line power flow is reduced to its scheduled value of 0 MW in approximately 200 seconds.

The area generation controller changes the power set point for the GCC plant, and the station controller adjusts the gas turbine set points accordingly. The rate of change of the gas turbine speed/load set points is limited to the range of 0.0025 to 0.0125 percent per second. The difference between the GCC plant generation and the demand which is requested by the network is governed by the rate of change of these set points. The maximum variation between power demand and power generation is about 3 MW, or about 4 percent of the 70 MW change. However, the rate of change of the speed/load set point is close to its minimum value for this run. Therefore, the difference between power demand and generation can be reduced if the speed/load controller set point were allowed to change faster.

The steam turbine power generation response lags approximately 150 seconds behind the gas turbine exhaust gas temperature.

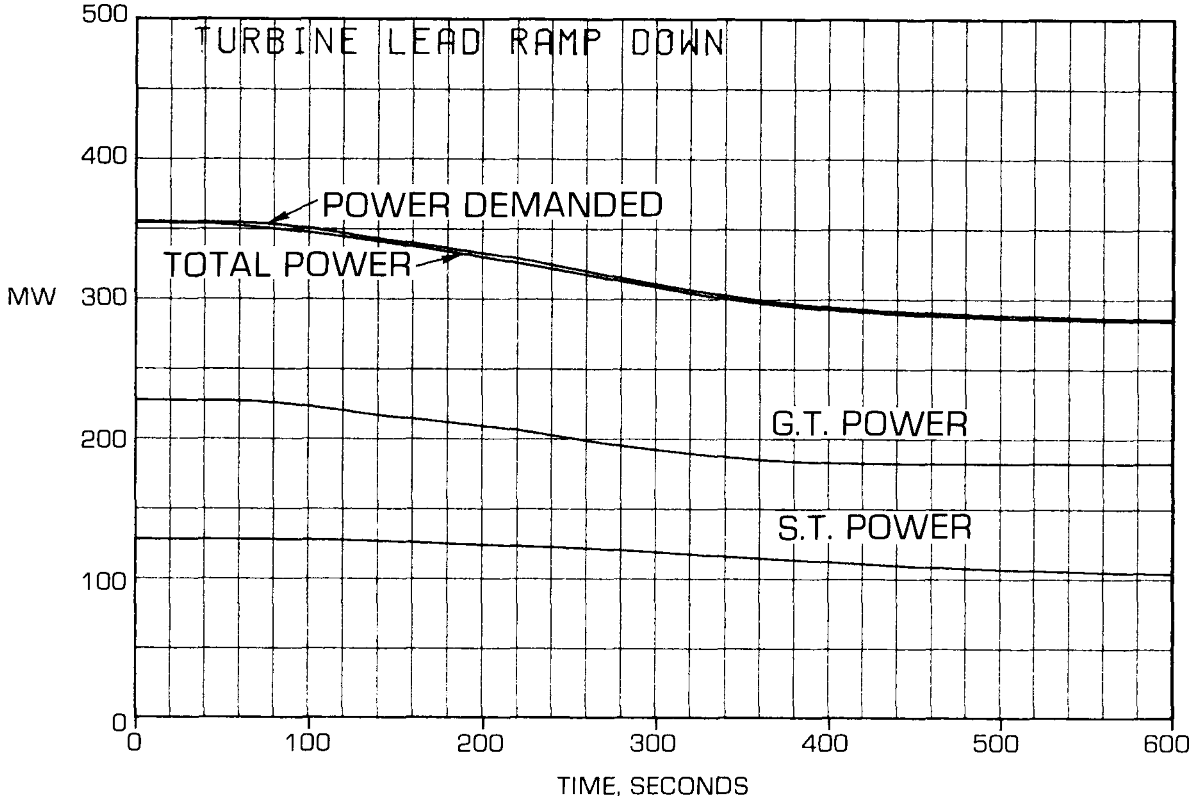


Figure 3-12. Turbine Lead Rampdown Control Run

TURBINE LEAD STEPDOWN

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at 353.6 total MW power generation. The power generation from 5.65 GCC power plants, as modeled, is connected to the network. Therefore, the total power input to the electrical network system from the GCC power plant is 1998.1 MW.

The power demand for Area I is 4000 MW. Of this, 2000 MW is generated by conventional fossil-fired steam plants. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80 GW (load is also 80 GW) and it is modeled with the characteristics of conventional fossil-fired steam plants. The tie-line flow is scheduled at 0 MW.

The load in Area I is changed from 4000 MW to 3200 MW instantaneously. This upset corresponds to a 20 percent load change in Area I and will require approximately 70 MW power decrease from each GCC power plant. The upset is introduced at 15 seconds.

<u>A 20 percent step change in Area I load causes a maximum variation of 0.114 cps in line frequency</u> (or change of frequency of 0.19 percent). The change in load of Area I is quickly met by a 765 MW step change in the tie-line flow to Area II. After the power plants in the Area I respond to the change in their set points, which is imposed by the Area I generation controller, <u>the tie-line flow decreases to its scheduled value of 0 MW in approximately 300 seconds</u>.

The area generation controller changes the power set point for the GCC plant, and the station controller adjusts the gas turbine set points accordingly. However, the rate of change of the gas turbine speed/load set points is limited between 0.0025 to 0.0125 percent per second. <u>The maximum variation between power demand and power generation is about 14 MW, or about 20 percent of the 70 MW change. However, the rate of change of the speed/load set point is close to its minimum value. Therefore, the difference between power demand and generation would be reduced if the set point were allowed to change faster</u>.

The gas turbine units of the GCC plant respond quickly to the load variation. The gas turbine exhaust temperatures drop, resulting in less steam generation and a decrease in steam turbine power output.

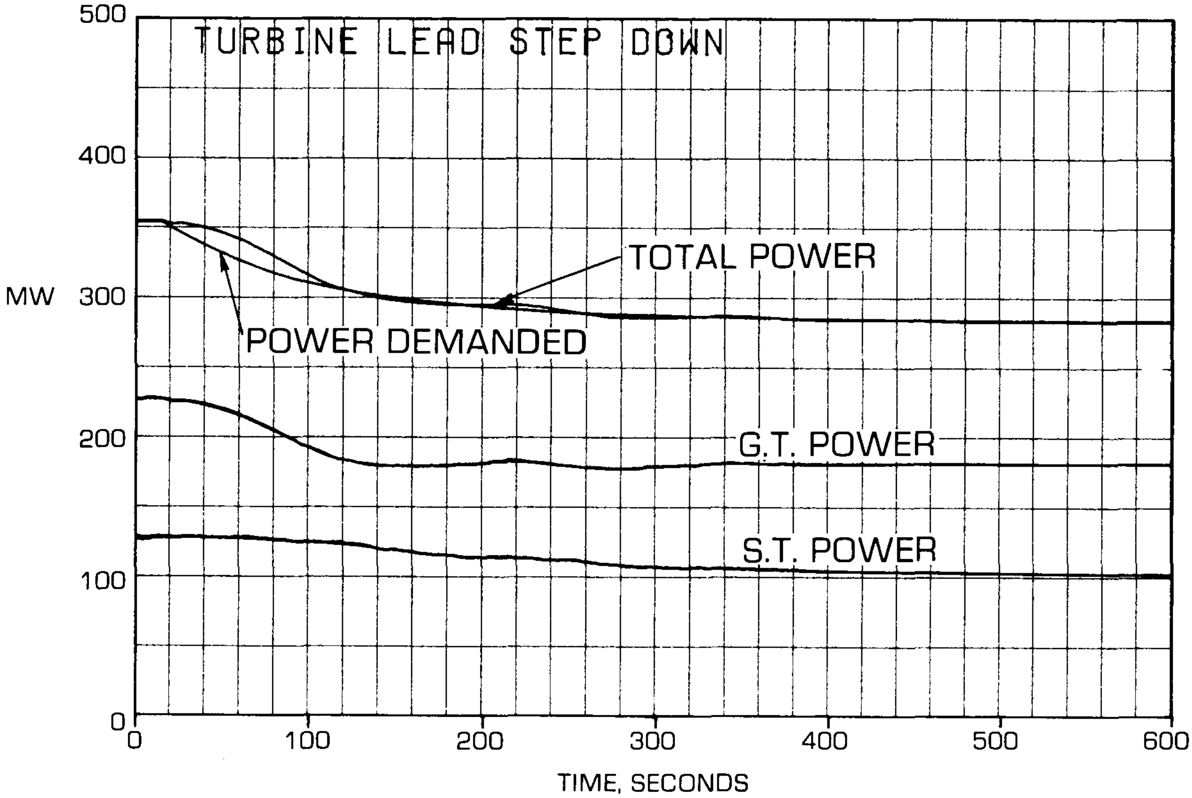


Figure 3-13. Turbine Lead Stepdown Control Run

TURBINE LEAD RAMPUP

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at minimum load which corresponds to 156.0 total MW power generation from two gas turbines, and 53.3 MW from the steam turbine. The power generation from 5.65 GCC power plants, as modeled, is connected to the network. Therefore, the total power input to the network system from the GCC power plant is 882.2 MW.

The power demand for Area I is 1764.2 MW. Of this, 882.0 MW is generated by conventional fossil-fired steam plants. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80 GW (load is also 80 GW) and it is modeled with the characteristics of conventional fossil-fired steam plants. The tie-line flow is scheduled at 0 MW.

The gas turbine speed and load controllers respond to the changes of the line frequency and load. The gasifier and gas turbine trains are operating in parallel mode.

The load in Area I is ramped from 1764.2 MW to 2115 MW in 300 seconds. This upset corresponds to a 4 percent per minute load increase for 5 minutes and requires approximately 31 MW more power from each GCC plant. The upset starts at 15 seconds and stops at 315 seconds.

A 20 percent ramp at 4 percent per minute causes a variation of 0.012 cps in line frequency (or change of frequency of 0.02 percent). The change in load of Area I is partially met by the tie-line flow from Area II. The tie-line power flow is slowly increased from a scheduled value of 0 MW to 103 MW during the period of load variation. Once the load approaches its new steady-state value, the tie-line power flow is reduced to its scheduled value of 0 MW in approximately 200 seconds.

The maximum variation between power demand and power generation is about 3 MW, or about 10 percent of the 31 MW change. However, the rate of change of the speed/load set point is close to its minimum value for this run. Therefore, the difference between power demand and generation will reduce if higher rate of change of the speed/load controller set point were allowed.

The steam turbine power generation lags approximately 200 seconds behind the gas turbine exhaust gas temperature.

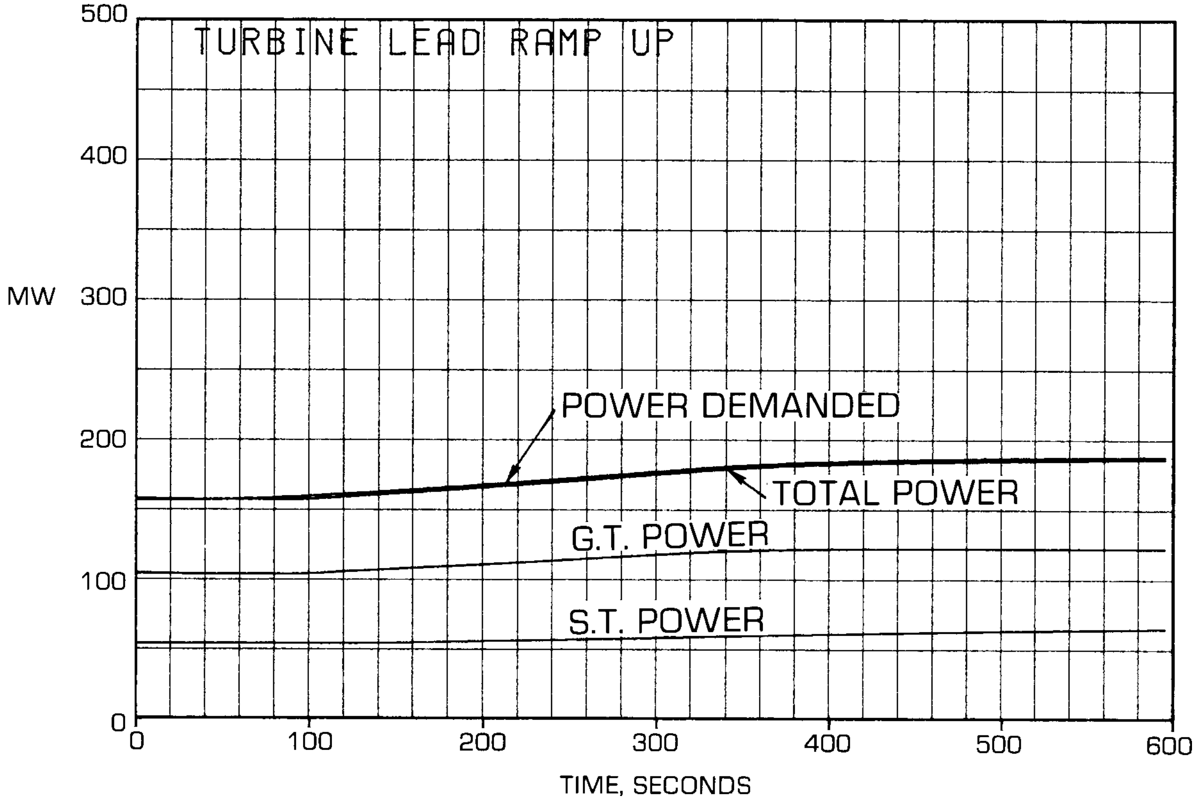


Figure 3-14. Turbine Lead Rampup Control Run

TURBINE LEAD STEPUP

The fuel gas process, gas turbine system, and heat recovery steam generation unit of both trains are operating at steady state at minimum load which corresponds to 156.0 total MW power generation. The power generation from 5.65 GCC power plants, as modeled, is connected to the network. Therefore, the total power input to the network system from the GCC power plant is 882.2 MW.

The power demand for Area I is 1764.2 MW. Of this, 882.0 MW is generated by conventional fossil-fired steam plants. Therefore, the GCC plant represents 50 percent of the generation in Area I. Area II generates 80 GW (load is also 80 GW). The tie-line flow is scheduled at 0 MW. The gas turbine speed and load controllers respond to the changes of the line frequency and load.

The load in Area I is changed from 1764.2 MW to 2115 MW instantaneously. This upset corresponds to a 20 percent load change in Area I and will require approximately 31 MW more power from each GCC plant. The upset is introduced at 15 seconds and a total of 10 minutes of plant operation is simulated in this run.

A 20 percent step change in Area I load causes a maximum variation of 0.048 cps in line frequency (or change of frequency of 0.08 percent). The change in load of Area I is quickly met by a 331 MW step change in the tie-line flow from Area II. After the power plants in Area I respond to the change in their set points, which is imposed by the Area I generation controller, the tie-line flow decreases to its scheduled value of 0 MW in approximately 240 seconds. A similar upset for the gasifier lead mode resulted in a similar transient with a 350 second duration.

The maximum variation between power demand and power generation is about 13 MW, or about 40 percent of the 31 MW change. However, the rate of change of the speed/load set point is close to its minimum value. Therefore, the difference between power demand and generation would be reduced significantly if the set point were allowed to change faster.

The gas turbine units of the GCC plant respond quickly to the load variation. Each gas turbine exhaust temperature rises, resulting in more steam generation and an increase in steam turbine power generation. The slow increase of steam turbine power generation results in a decrease in the total gas turbine power generation from its maximum value.

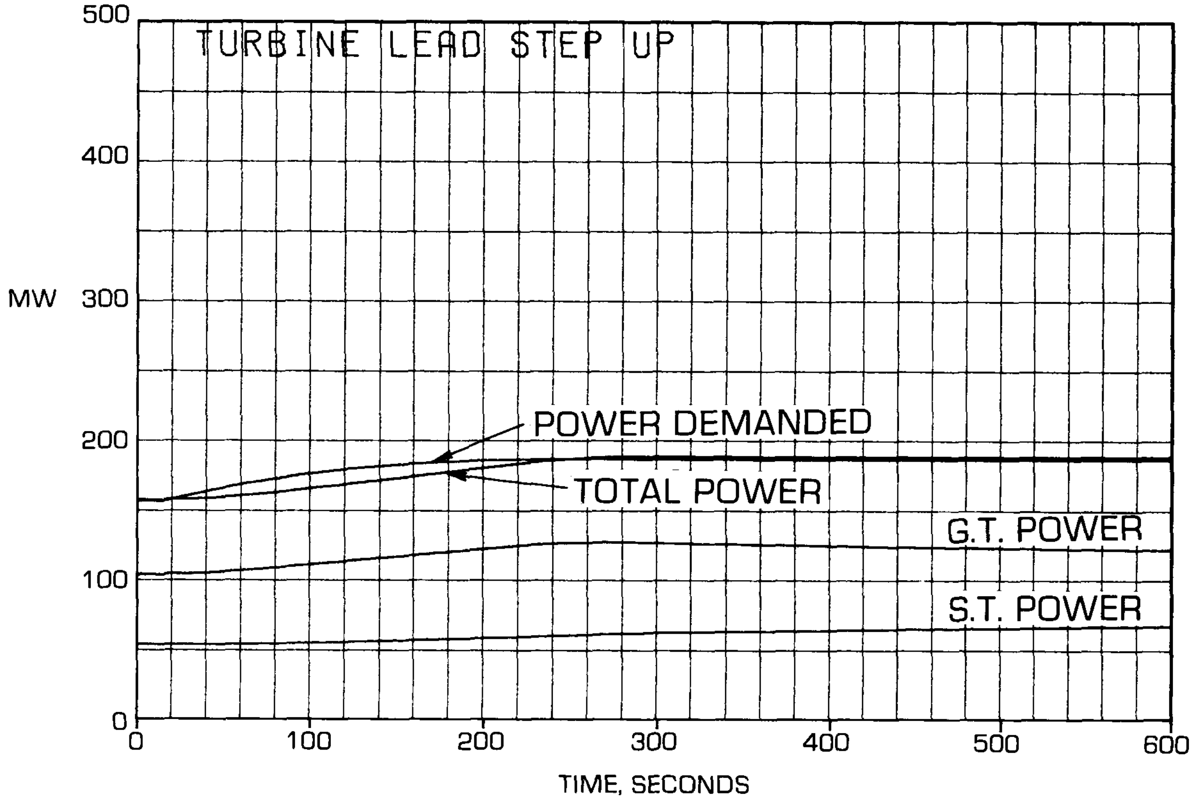


Figure 3-15. Turbine Lead Stepup Control Run

C O N T I N G E N C Y   O P E R A T I O N

GASIFIER TRIP

Loss of one gasifier reduces the capacity of the fuel processing plant to supply fuel gas to the gas turbines by 50 percent. The lower gas production also reduces steam production not only in the fuel processing plant but also in the HRSGs as a result of lower gas turbine exhaust temperature and flow.

For this transient we have also chosen simultaneous shutdown of an oxygen plant train as one alternative to accommodate an emergency trip of a gasifier. The gasifier trip would be effected by the automatic quick closure of shutoff valves.

Slurry flow for one gasifier rapidly decreases to zero. Oxygen plant variables change quite quickly to single train operation. Oxygen flow to the affected gasifier becomes zero. Gaseous production is cut in half and the pressure controller sets liquid evaporation to the minimum in about 50 seconds. Fuel processing plant HP and IP steam make for the train that has tripped become zero within the first 20 seconds while MP steam make drops to about 66 percent of the two train rate.

Gas turbine inlet guide vanes closed in less than 30 seconds, causing compressor flow to decrease almost 25 percent. The gas turbine combustion temperature dropped almost 600°F in 30 seconds which is a large temperature shock for the gas turbine equipment. Gas turbine power decreased from 113 MW to 36 MW for each gas turbine.

In the HRSG, the flue gas is too cold to maintain superheat and reheat temperatures as the control loops close the temperature control valves. However, the steam temperatures after reheat and superheat have not decreased enough to trip the steam turbine. HRSG HP steam make first increases and then decreases, slowly approaching 66 percent of the original steam make. HP steam header pressure decreases from 1422 psia to 813 psia and IP header pressure decreases from 342 psia to 190 psia. Steam power decreased from 137 to 65 MW at 10 minutes time. Total plant power has decreased to 39 percent of full load.

If automatic dual fuel firing (oil and gas) are initiated at the gas turbines when the gasifier trips, power output could be preserved. Alternatively, if one gas turbine is switched to oil firing, most of the power production could be preserved.

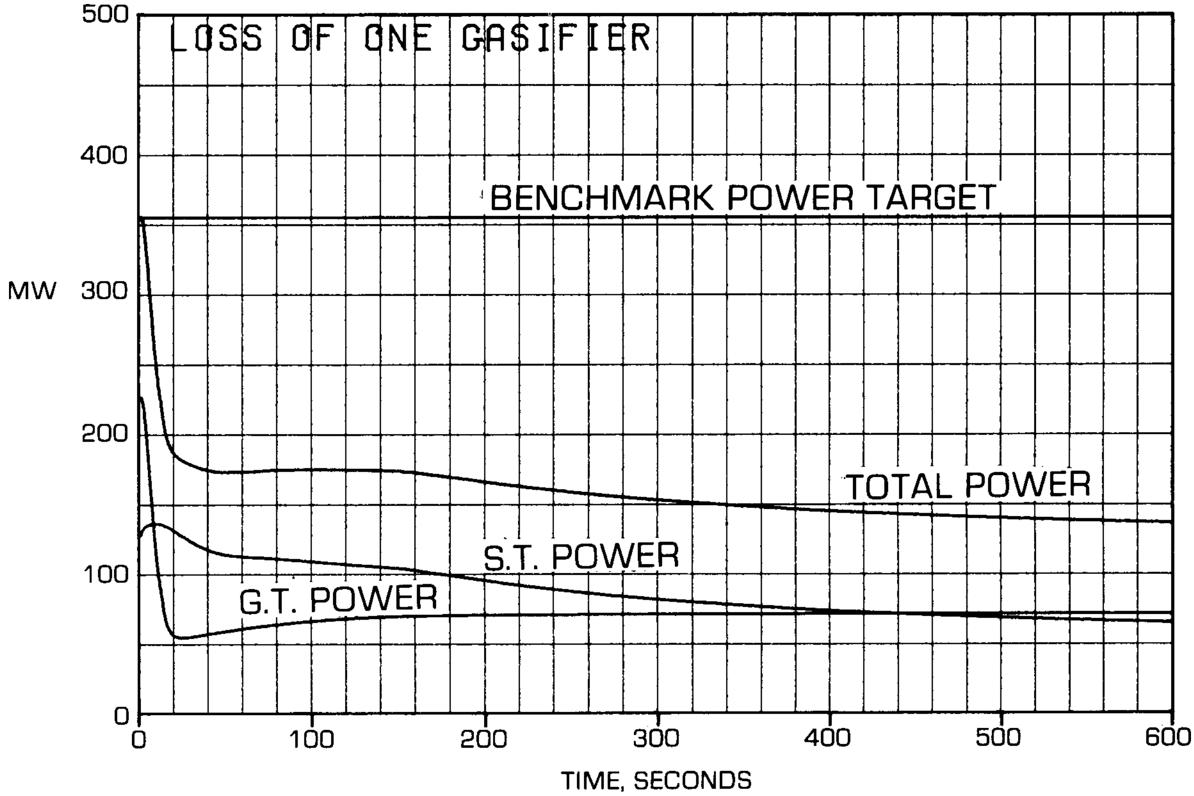


Figure 3-16. Gasifier Trip

OXYGEN PLANT ONE TRAIN TRIP

When a train in the oxygen plant ceases to produce gaseous oxygen, gasification capacity must be reduced. In this simulation, one train of the oxygen plant was tripped at 10 seconds. At the same instant the set point of the oxygen flow controllers was ramped down over the next 15 seconds to the flow corresponding to one gaseous train plus the liquid evaporator flow. At this point we decided to show the advantage that the evaporator system offers by increasing the gasifier set points on a ramp which recovers the flow about as fast as the design ramp capacity of the evaporator system. The purpose of this exercise was to show that most of the lost power output can be recovered within 10 minutes, even though one train of the oxygen plant is not operative.

Oxygen plant variables changed significantly. Gaseous production dropped in half in one second as one train tripped. Almost immediately thereafter the liquid evaporation increased under pressure control to be equivalent to one train output at about 400 seconds. Driver steam dropped to the new steady flow appropriate for one train.

At the gas turbines, significant changes occur as a result of the oxygen plant trip. With essentially a 10 second lag after the oxygen plant trip, the inlet guide vanes start to close and are closed at 30 seconds. Later on, the inlet guide vanes reopen halfway. Combustion temperature dips 450°F and then recovers linearly to within 50°F of its original value. The gas turbine power decreases to a minimum of 45 MW at 35 seconds and then linearly increases to 95 MW at 400 seconds. This is about 84 percent of the original gas turbine power before the trip.

During the transient, temperature control of the reheat steam temperature is lost at 60 seconds but it is back on control 100 seconds later. Steam rates reach 80 to 90 percent of their original rates. HP steam pressure dipped 300 psi at 300 seconds and then recovered about 100 pounds of the dip, whereas IP steam dipped only 40 pounds with full pressure recovery at 10 minutes. Steam power increased slightly at the onset of the trip due to reduced demand at the oxygen plant, dipped 20 MW and then recovered to be just 4 MW below the initial value.

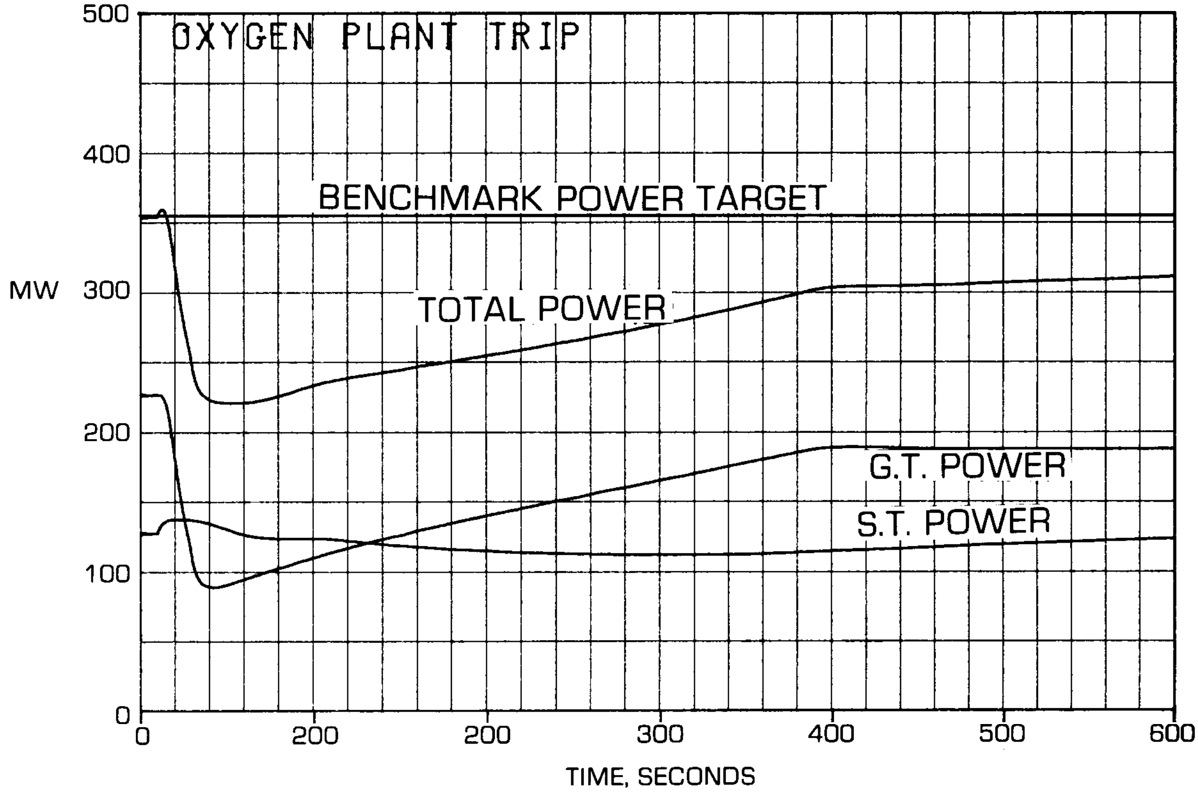


Figure 3-17. Oxygen Plant One Train Trip

LOSS OF ELECTRICAL LOAD AT A SINGLE GAS TURBINE

When a gas turbine loses electrical load, the gas turbine speed/load controller takes over and the fuel gas flow to the gas turbine is reduced until the gas turbine is rotating at full speed while producing no power. About 30 percent of full load fuel is just adequate to run the air compressor by expanding the combusted fuel gas. We have assumed that process fuel gas production will not be altered for this transient. Therefore, excess fuel gas will be flared during the upset (the flare gas flow rate is about 1.8 lb moles/s, and operating pressure of the plant increases 20 psi as pressure control switches from gas turbine control to the flare pressure controller).

Starting with the benchmark steady state, one gas turbine generator is tripped at 10 seconds. Since the affected gas turbine is consuming less fuel, plant pressure increases. Within 10 additional seconds the pressure at the gasifiers has reached a maximum, about 15 psi above the normal operating pressure of 612. Flow of oxygen and slurry into the gasifier remain at the set point. In the oxygen plant, the fuel gas expander horsepower supplied to the drivers decreases due to reduced fuel gas flow to the gas turbines.

When one gas turbine generator trips, the control modes of both gas turbines change. The affected gas turbine goes to speed control and the other gas turbine switches to temperature control to consume as much fuel as possible within temperature limits (its power generation increases almost 8 MW). The IGV of the tripped turbine has closed within 10 seconds. Inlet air flow has decreased and operating pressure of the compressor has dropped 100 psi. The combustor outlet temperature decreased temporarily over 1000°F before lining out near 1380°F. The exhaust temperature has decreased to 740°F.

In the two HRSGs, each operating at different temperatures and flue gas flow rates, the steam side temperatures vary significantly from one train to the other. In the hot train superheat and reheat temperatures are 400°F above the cold train. For the cold train, HP steam generation has dropped to one-third of design and IP generation increased 160 percent. The HP pressure has only decreased 220 psi and IP header pressure decreased less than 130 psi. Superheat and reheat temperatures at the steam turbine inlet have decreased less than 100°F and a steam turbine trip will not be necessary. After the initial loss of the power output of one GT, total plant power generated decreased gradually due to gradual loss of steam power.

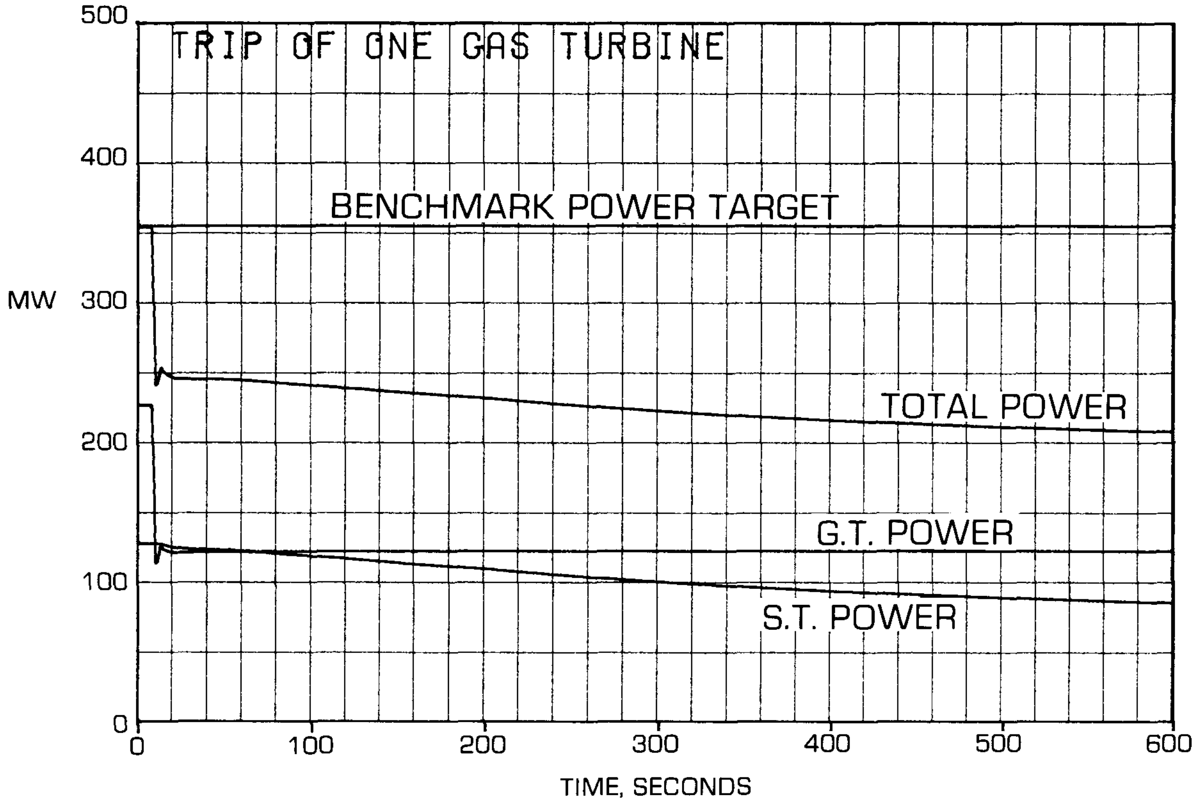


Figure 3-18. Loss of Electrical Load at a Single Gas Turbine

LOSS OF ELECTRICAL LOAD AT TWO GAS TURBINES

A trip of two gas turbine generators in a two gas turbine plant, is the loss of all gas turbine electrical load which is an extreme event when considering there would be loss of seven gas turbine generators in the full sized EXTC plant. We simulated the two gas turbine generator trip as an isolated event not followed by additional trips. After analyzing the data from the run, we recognize that additional events such as a steam turbine trip and a trip of one of the two oxygen trains would most likely be instigated in a real plant.

Starting with the benchmark steady-state operating data with the gas turbines on pressure control, the two gas turbine generator trip was instigated at 10 seconds. Both gas turbines switch to speed control and the fuel gas demand at the turbines drops to about 30 percent. This forces the plant pressure to increase until the process flare valve opens.

As a result of decreased gas turbine exhaust temperature, the temperature of the fuel gas entering the expander drops from 970°F to 758°F in the first 5 minutes. Depending on the design of this equipment, a 200°F temperature shock may require a bypass of the expander to extend its lifetime. At the gas turbines, the IGVs start to close at 13 seconds and finish closing before 20 seconds. Gas turbine power becomes zero in less than one second.

Steam temperatures out of the reheaters and superheaters drop almost 300°F in the first 5 minutes. The reheater temperature control is fully closed at 30 seconds and the superheater temperature control is fully closed before 90 seconds. The reheat steam temperature decreases so much that the steam turbine should be tripped. IP steam pressure is decreasing rapidly due to low production and demand at the oxygen plant drivers. The low IP steam pressure points out the mismatch between the sliding pressure operation of the power turbine and the need for constant pressure to be supplied to process plant drivers. It is not feasible to have oxygen plant steam drivers designed to receive steam whose supply pressure varies by as much as a factor of 2. Therefore, either the steam turbine system should be changed to accommodate constant pressure headers or the oxygen plant compressors should be changed from steam drive to electric motor drivers.

Steam turbine power has dropped 50 percent at the 5 minute mark and is still decreasing.

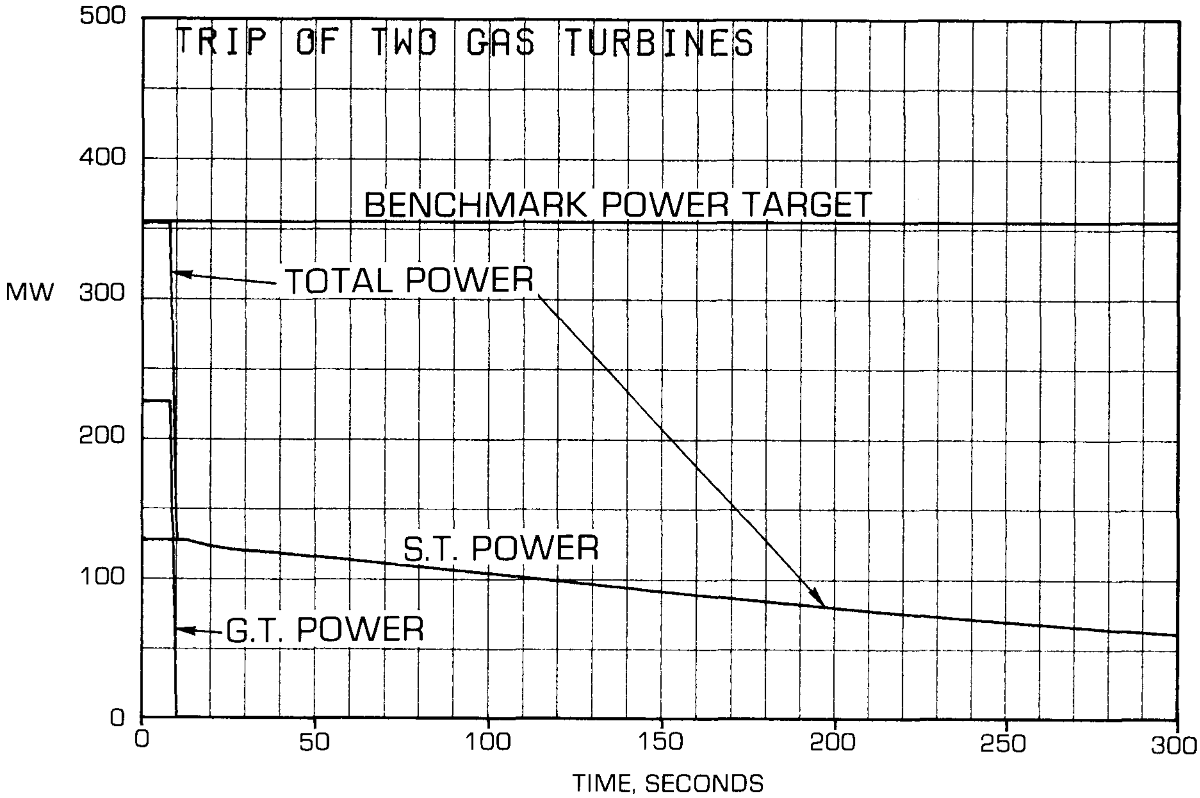


Figure 3-19. Loss of Electrical Load at Two Gas Turbines

LOSS OF ELECTRICAL LOAD AT THE STEAM TURBINE

Loss of the steam turbine generator has been simulated such that the steam turbine speed controller takes over upon loss of the generator which is lost at 15 seconds into the simulation. The steam valves, both the throttle and interceptor, close within 1 second after the trip and are reopened before 50 seconds to keep the steam turbine on full speed no load. In our model, less than 0.2 lb moles/s are required to keep the steam turbine rotating at full speed.

Since the fuel processing plant variables are only affected indirectly, fuel processing plant flows, temperatures and pressures are not changed very much. The gas turbines are also not affected by the steam turbine trip. Their power generation is constant and flows, temperatures and pressures remain the same.

The steam not going to the steam turbine is quenched with BFW and bypassed around the turbine. Makeup condensate flow to the deaerator increases about 42 percent. The deaerator control scheme should be reinvestigated for this high water flow case. Since this high water flow cannot pick up enough heat from the fuel plant exchangers, the deaerator pressure will dip sufficiently to starve the pumps (insufficient net positive suction pressure). Rapid response of the "pegging steam" valve at reasonably high steam flows is required.

During the initial part of the steam turbine trip, the turbine valves close faster than the bypass valves open. HP steam pressure increases less than 20 psi before the bypass is open. In our models, for a few seconds, the HRSG HP steam generators cease steam production. The steam flows to the superheaters briefly dip to one-third normal and then are restored. The HRSG IP steam system shows similar behavior. IP steam generation decreases but not as sharply, and reheater steam flow dips.

HP superheated steam is let down through a desuperheater to the cold IP header. Since this desuperheated steam is closer to saturation than the HP turbine exhaust steam normally feeding the header, the steam reheaters are overloaded. They come off temperature control at about 110 seconds. With the additional mass flow from the desuperheaters, the IP steam reheat temperature drops 70°F.

Because of the much larger water flows in the HRSG, the flue gas temperature leaving the HRSG drops almost 30°F to 248°F. This is not expected to produce any corrosion problems in the LP evaporator tubes.

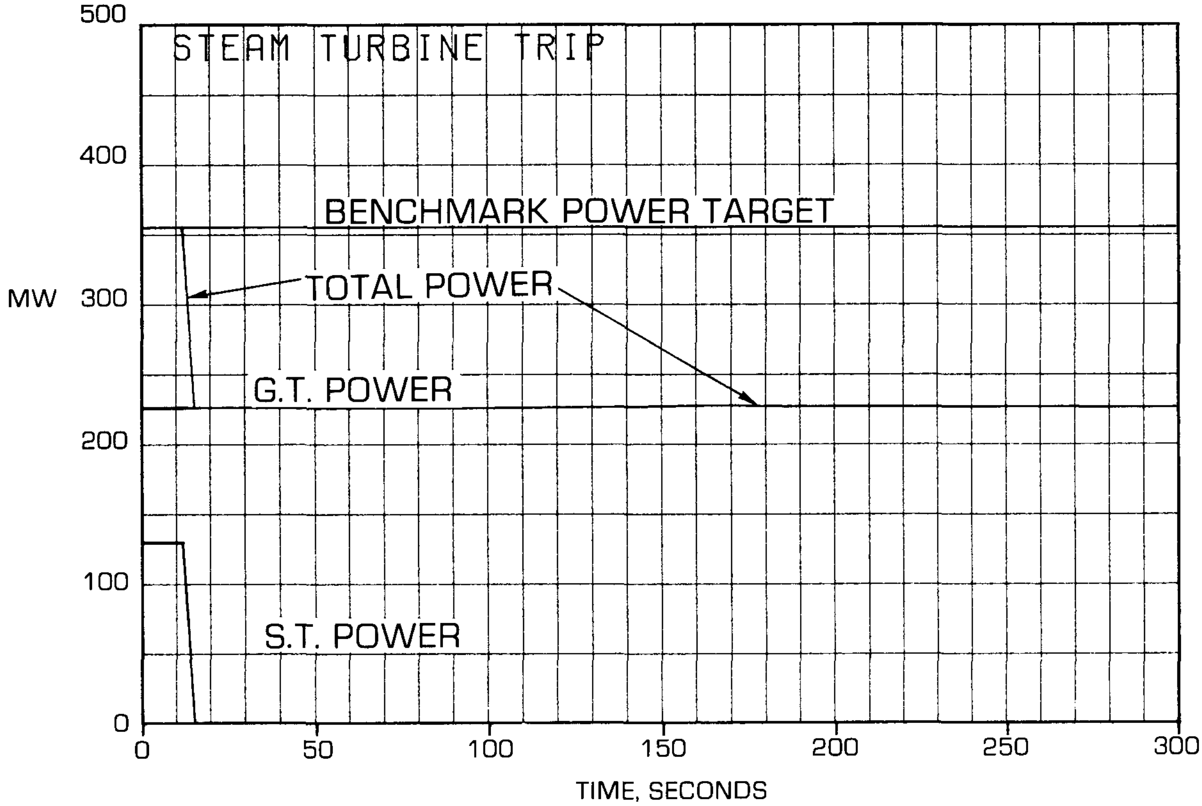


Figure 3-20. Loss of Electrical Load at the Steam Turbine

LOSS OF ALL ELECTRICAL LOAD

When all electrical load is lost, the fuel demand at the gas turbines is reduced to about 30 percent. We have decided for the simulation to trip an oxygen train and decrease the gasifier set points, rather than permit a large process flare flow. This is but one possible alternative for the process plant experiencing loss of all electrical load.

At 10 seconds, the gas turbine generators and steam generator were tripped and power output dropped to zero in less than one second. The steam turbine valves remain closed for 30 seconds and then partially reopen to maintain full speed on the turbine. Fuel gas flow to the gas turbines drops to 30 percent and the flare valve opens to let the remaining excess gas leave the plant on pressure control.

At the gasifier, oxygen flow is reduced to 40 percent. At this reduced throughput, gasifier pressure drops 40 psi. During the pressure dip the calculated gasifier temperature decreases temporarily, but gasifier effluent composition is not affected. At 10 seconds, one of the two oxygen plant trains trips and the oxygen header pressure dips until the new gasifier set point flow is reached 15 seconds later.

At reduced gas turbine exhaust temperatures, the HRSG heaters warm the fuel gas to 740°F, not the normal 970°F at the design point. As mentioned for earlier runs, it may be necessary to bypass the expander to avoid this temperature shock. IGVs are closed within the first 10 seconds after the trip, gas turbine air flows and pressures have reached minimum. The net result is a decrease in the exhaust temperature to about 743°F.

All of the general features described in the steam turbine loss of electrical load occur in this run also, except flow and temperature transients are of different magnitude due to the reduced gas turbine exhaust temperatures. HRSG HP and IP steam generation are temporarily stopped as the steam turbine throttle and interceptor valves close and the bypass valves are not completely open. With total steam generation decreasing, the HP steam pressure decreases 650 psia. However, the IP steam pressure increases to the 400 psia set point of the IP header pressure controller.

Total power generated reaches zero within one second. The gas turbines switch from pressure control to speed control immediately after the trip.

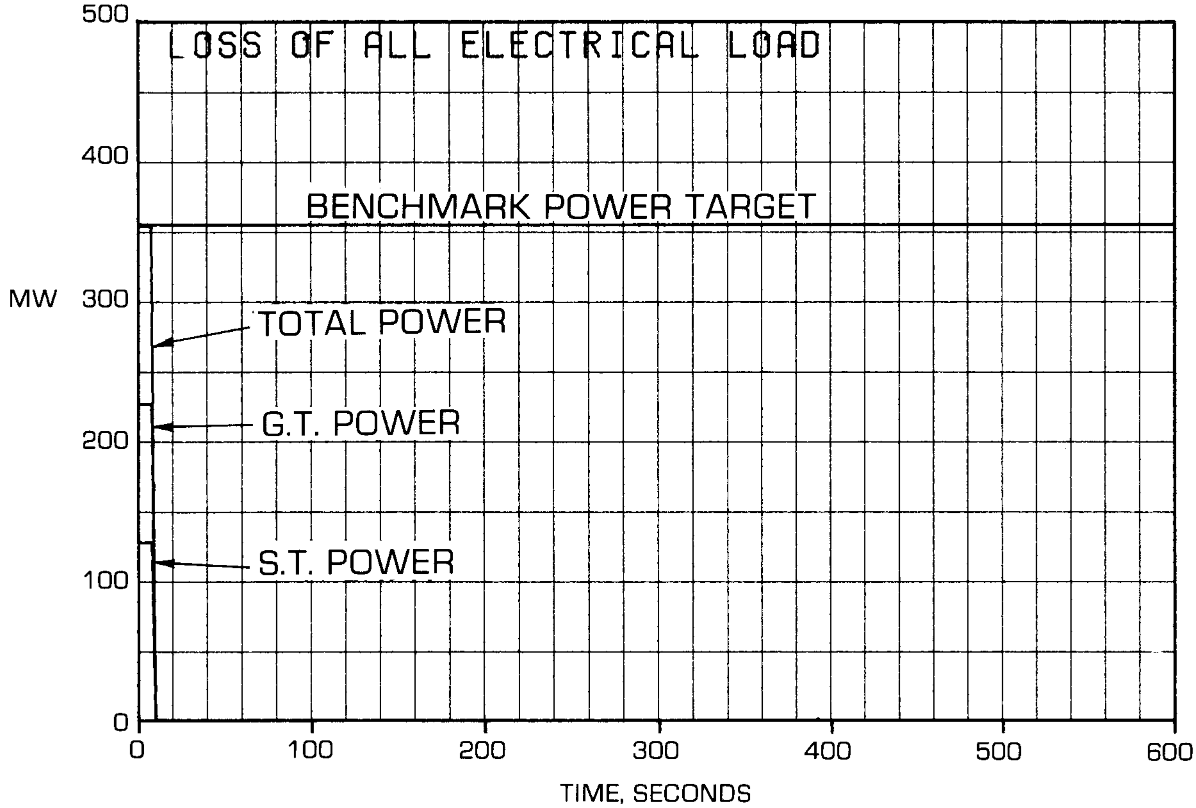


Figure 3-21. Loss of All Electrical Load

LOSS OF ONE HRSG

To simulate the loss of an HRSG, we wanted to indicate the effect of stored energy in the water and metal on the steam system dynamics. Accordingly, we turned off a gas turbine and set the flue gas flow rate to zero for that gas turbine train. As with earlier runs, the fuel processing plant gas production was constant and the process flare valve opened to discharge the surplus gas.

When one gas turbine was turned off at 91 seconds, the other gas turbine switched to temperature control. Its operating conditions increased slightly with higher fuel rate and power increased 8 MW.

When the clean fuel gas, split equally between the two trains, flowed through the HRSGs the gas was heated to significantly different temperatures. In the cold train with no flue gas flow, the gas temperature dropped from 970°F to 600°F in 500 seconds, while in the hot train the gas temperature associated with the other gas turbine, which switched to maximum firing temperature, increased 60° to 1130°F.

All of the other HRSG exchangers behaved in a similar fashion. In the hot train, the superheater and reheater temperatures increased with increased flue gas temperature. In the cold train, temperatures dropped 460°F and 510°F for the superheated steam and reheated steam. Since the mixed streams were no longer above the temperature control set points, the temperature control systems shut off the bypass temperature control flows: the reheater bypass flow in 90 seconds, and the superheater bypass flow in 180 seconds. The steam temperatures at the turbine inlet were reduced 180°F in reheat and 135°F in superheat. These temperature drops are substantial enough to consider either a steam turbine trip or closing the isolation valves on the cold HRSG.

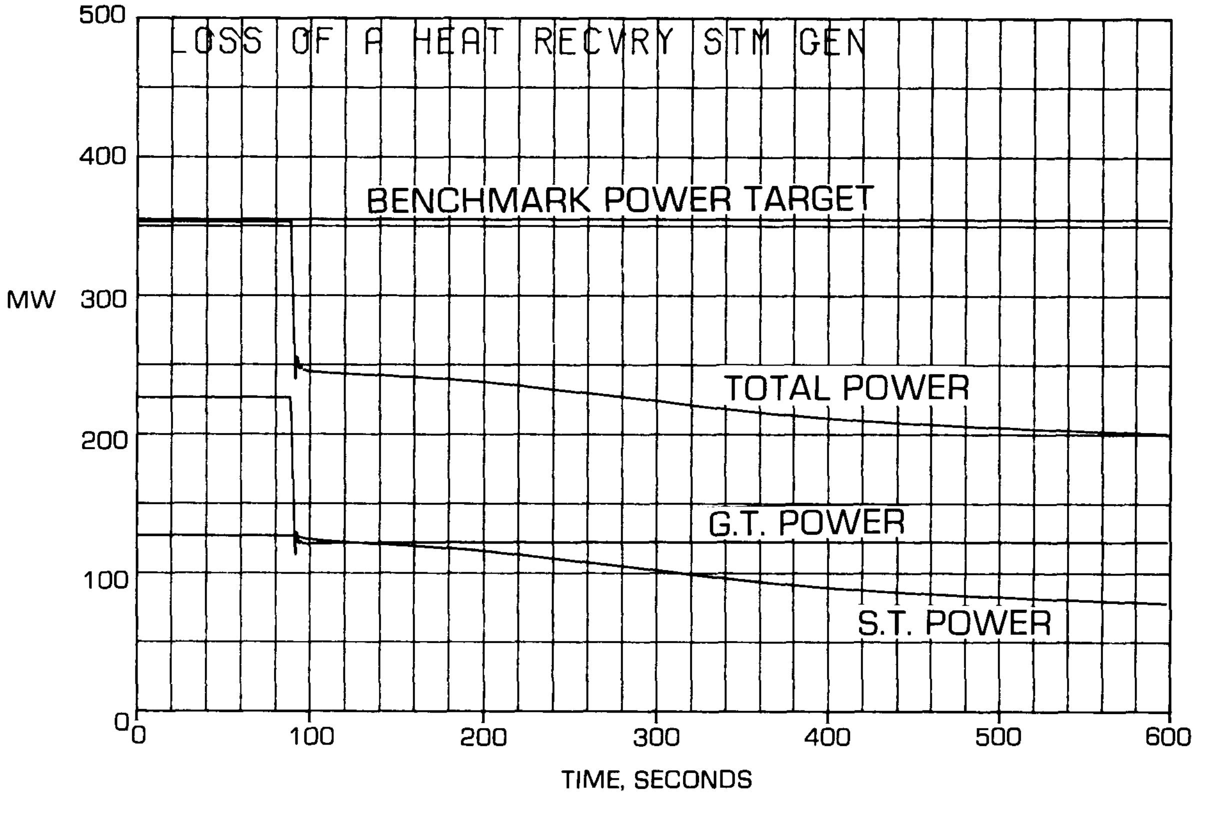


Figure 3-22. Loss of One HRSG

LOSS OF GAS FUEL VALVE, TRANSFER ONE GAS TURBINE TO OIL

In case of a faulty fuel gas valve at the gas turbine which does not cause a gas turbine trip (which we have already studied), it may be necessary to transfer the fuel gas-fired turbine to fuel oil as rapidly as possible. To accomplish this, the gas turbine controller has been programmed to accomplish a fast fuel transfer. The gas turbine fuel gas flow is first reduced to the minimum as rapidly as possible. After a short delay, the oil flow begins a minimum flow, and then the oil flow is increased to the maximum flow while the gas flow is reduced to zero. The entire transfer takes place within 10 seconds. The transfer is somewhat bumpy. First the turbine power goes down as gas flow reduces to the minimum. After the four seconds it takes to start the oil pumps and fill the line, the oil flow jumps up to minimum flow causing the turbine power to increase. By this time, the IGV control loop has started to close the guide vane, but when oil flow starts the guide vane controller returns the vane to the full open position. The remaining portion of the fuel transfer is smooth. The exact amount of oil required was determined by the temperature controller at the exhaust temperature limit. As it turns out, the net power generated by the oil fired turbine is only 91 percent of the gas fired turbine power. The power produced by the remaining gas turbine goes up as it switches from pressure control to temperature control.

The oxygen flow to the gasifiers remained constant during the fuel transfer. In the oxygen plant, gaseous oxygen production rises slowly under header pressure control to reduce slightly the amount of liquid oxygen being evaporated.

Since both gas turbines are operating on temperature control, the flue gas temperature entering the HRSGs is hotter by up to 50°F than when operating on pressure control and gas firing. Accordingly, the amount of steam bypassing the superheaters and reheaters, respectively, increases to maintain the temperatures of both steam streams constant. The flue gas temperature profile in the HRSG above the superheater-reheater level remains nominally constant. The steam production in the HRSG is slightly lower for the oil fired turbine due to less mass flow. The overall changes in the steam system are quite small. Steam turbine power varied less than one percent during the transient.

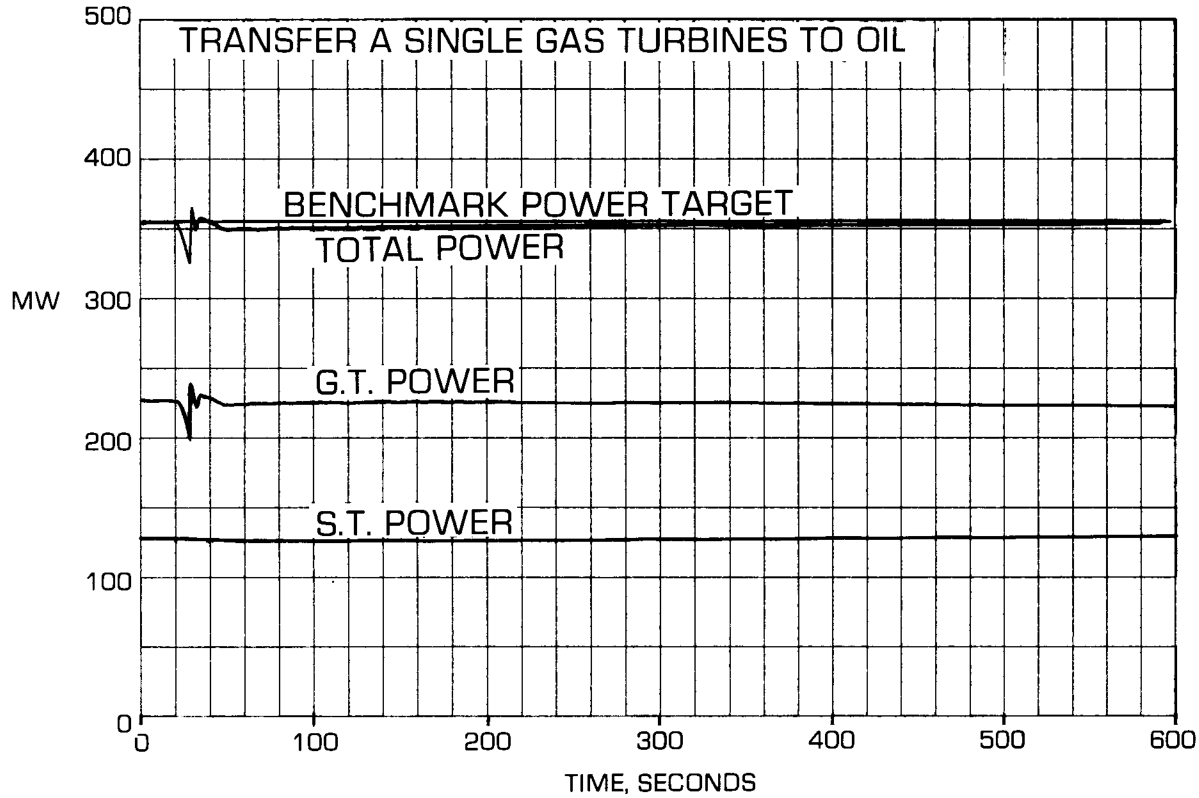


Figure 3-23. Loss of Gas Fuel Valve, Transfer One Gas Turbine to Oil

STEADY STATE WITH ONE GAS TURBINE ON OIL

The previous run was of short duration. Since HRSG exchanger time constants are on the order of 200 seconds, we have elected to extend the oil transfer run to steady state by continuing the previous run.

The gasifier variables had already reached steady state. However, the gaseous oxygen production had not reached its maximum which will occur when the evaporator reaches its minimum design throughput. This is attained after another six minutes have elapsed. At this point, oxygen plant driver power has reached a maximum.

In the fuel processing plant, the gas temperature profile changes ever so slightly from the temperatures reached in the earlier run. Fuel flow and flare flow had already stabilized.

At the gas turbine, all variables had reached their new values, except for a small stable oscillation in the temperature control loop regulating oil flow.

In the HRSG, however, temperatures and flows were slowly approaching their final values where the maximum differences in the oil fired and gas fired train are realized. With essentially equal steam flows in each train, the superheater and reheater exit temperatures achieved are some twenty odd degrees apart. Nonetheless, the flue gas temperature profile in both trains remain remarkably close, varying less than 4°F. Water temperatures in the economizer trains are also close, with less than 5°F differences. However, HP and IP steam production are higher in the gas fired train by 2 percent and 10 percent respectively. Steam turbine variables reach their steady values about six minutes into the run: header pressures, steam flows, temperatures, and power are then constant.

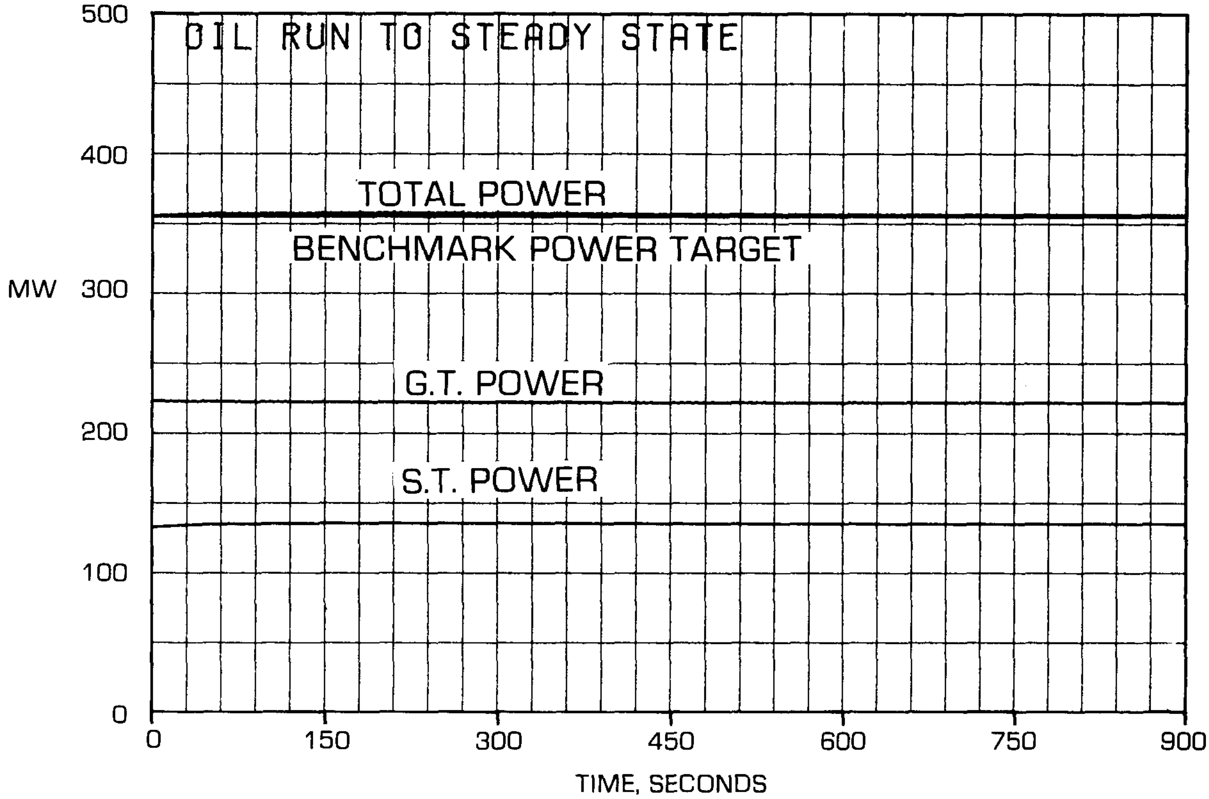


Figure 3-24. Steady State With One Gas Turbine On Oil

Section 4

CONTROL ANALYSIS

STATION CONTROLS (CLOSED-LOOP RESPONSES)

Two control modes for GCC power plant operation were considered in this study: the gasifier lead and gas turbine lead.

Gasifier Lead Mode

The gas turbine control system maintained a constant pressure in the fuel gas plant just downstream of the Selexol column. The station controller adjusted the set point of the gasifier flow controller based on the difference between total power generation and the GCC plant MW power demand which was determined by the electrical network area generation controller. The maximum ramp rate allowed for adjustment of the gasifier flow controller set point was 5 percent per minute. Oxygen feed flow was the limiting factor for plant response to electrical network requirements.

Turbine Lead Mode

The station controller maintained the plant pressure (i.e., in the fuel gas header downstream of the Selexol column) by adjusting oxygen flows to the gasifier. The gas turbine speed/load controller responded to the power demanded from the area generation controller via "raise/lower" and "rate signals" from the station controller. In most of the test runs the "rate" was very near its minimum of 0.15 percent per second. The GCC plant was limited in response to the electrical network requirements by the "rate signals" changing the set point on gas turbine speed/load controller.

It was necessary to increase the maximum ramp rate for the oxygen flow set point to 10 percent per minute for 20 percent instantaneous load decreases, to prevent flaring of processed fuel gas.

Load Changes Studied

Four test runs were made in each mode of plant operation:

- 20 percent decrease in electrical load at 5 percent per minute when the GCC plant was near full load
- 20 percent instantaneous decrease in electrical load when the GCC plant was near full load
- 20 percent increase in electrical load at 5 percent per minute when the GCC plant was near its minimum load
- 20 percent instantaneous load increase in electrical load when the GCC plant was near its minimum load

Power Responses

The maximum change in line frequency, tie-line power flow, plant pressure, and the maximum deviation between GCC plant power generation and the power demanded by the electrical network, are summarized for the closed-loop control runs in Table 4-1. In general, it can be concluded that the GCC plant can satisfactorily participate in load following in both gasifier and turbine lead modes.

Load Ramps

For the rampdown and the rampup runs both in gasifier lead and turbine lead, the control system responds quite closely to the power demand. For these 20 percent load changes in Area I, the maximum deviation in GCC generation and power demand was only 3 MW. For the rampdown runs the ability to follow load included the movement of the gas turbine inlet guide vanes from full open to nearly closed, whereas for the rampup runs the inlet guide vanes remained fully closed. As seen in the power plots presented in the results section, all quick generation response to power demand is provided by the gas turbine, since the steam system responded very slowly.

For "frequency participation," the speed error (line frequency error) is sent directly to the gas turbine fuel valves via the speed/load controller in gas turbine lead mode. For gasifier lead mode, the speed error was not sent directly to the gasifier oxygen flow controllers, because we did not want to achieve "frequency participation" by occasionally depressurizing the oxygen header. Turbine lead control showed more oscillation of generation about the power demand curve due to the direct connection of frequency error to the gas turbine. Nonetheless, the tie line power and network frequency changes are essentially the same for gasifier lead and turbine lead.

Table 4-1

SUMMARY OF CLOSED-LOOP CONTROL STUDY RESULTS

	20% RAMPDOWN		20% STEPDOWN		20% RAMPUP		20% STEPUP	
	GL	TL	GL	TL	GL	TL	GL	TL
Maximum change in line frequency, CPS	0.024	0.024	0.108	0.114	0.012	0.012	0.048	0.048
Maximum variation in tie line, MW	232	231	761	765	102	103	334	331
Maximum deviation in GCC power generation and power demand, MW	1.4	3	16.	14.	.6	3.	3.	13.
Maximum change in plant pressure, psi	1.7	2	3.5	7.	.6	3.5	1.5	2.5
Initial GCC plant power generation, MW	353	353	353	353	156	156	156	156
GCC plant final power generation, MW	283	283	283	283	187	187	187	187

GL = Gasifier Lead Operation Mode
TL = Turbine Lead Operation Mode

The GCC plant power changes were 70 MW down when ramping down and 31 MW up when ramping up. These changes are reflected in the magnitudes of tie line power, 232 peak (rampdown) versus 103 peak (rampup), and also in the frequency change, 0.024 cps peak versus 0.012 peak.

Both control schemes easily follow load changes characteristic of morning pickup and evening rundown.

Load Steps

The step runs demonstrate that both control schemes have the ability to share in picking up or dropping large loads within 10 minutes. The sizes of the steps were equal to the size of the ramp change in load. Therefore, the changes in network parameters only reflect the more rapid changes inherent in the step. As can be seen in Table 4-1, maximum variations in tie line power are more than 3 times larger for the steps than ramps. Maximum frequency changes are 4 times larger.

The maximum tie line power (as well as the maximum frequency change) is almost identical for each control method with the same load change. The turbine lead control scheme showed more oscillation in power generation versus demand because of the direct link of frequency error to the gas turbine controller.

The maximum deviation between power generated and power demanded was significantly greater for the step runs than the ramp runs, because the step and ramp limits built into the station controllers prevent faster response.

Oxygen Supply Requirements

The following oxygen supply rates were required at the gasifier for closed loop control under the load changes imposed on the network:

- For 20 percent load step
  - oxygen supply changes of 3 percent of design flow per minute for 3 minutes
- For 20 percent load ramps at 4 percent per minute
  - oxygen supply changes of 2 percent of design flow per minute for 5 minutes

Since the imposed load changes are large, these supply changes represent target rates for oxygen plant design.

These rates are significantly above the <u>gaseous</u> oxygen supply rate of 25 percent per hour (0.42 percent per minute) assumed for this report; we have achieved the supply rates listed by including a <u>liquid</u> oxygen evaporator in this study. However, as long as the supply is available by whatever means, the conclusions are valid. That is, we are not suggesting that liquid oxygen evaporators are necessarily required. More detailed study on the design and control of an oxygen plant are required before an optimum supply system can be defined.

RUNUP FROM MINIMUM AND RUNDOWN FROM FULL LOAD (OPEN-LOOP RESPONSES)

The GCC plant can respond quite well to decreasing or increasing power for both gradual changes typical of load following and also for successive rapid changes typical of tie-line thermal backup:

- Two percent per minute ramps in GCC plant electric power output for 20 minutes duration are easily achieved.
- Four ramps at 10 percent per minute in GCC plant electric power output separated by 1 minute pauses are easily achieved.

CONTINGENCY OPERATION

The local controllers as presented in the flow sheet (Volume II) and studied herein appear quite adequate to maintain the GCC plant operating during all of the emergency upsets we have examined. Observations based on these runs are:

- When an all gas turbine load trip occurs, the steam temperatures drop enough to recommend that a steam turbine trip should follow. A steam turbine trip is not required under a single gas turbine trip.
- Deaerator pressure control should be designed to handle the total water flow associated with a steam turbine trip at full gas turbine electrical load. The integrated plant design providing process heat to the deaerator is not adequate at high water flows to supplement LP steam heating of the deaerator. More steam is needed. The same is true for loss of all electrical load where the steam turbine is also tripped.
- If a continuous liquid oxygen evaporation system is included in the design, then gas production capacity lost due to an oxygen plant single train trip can be made up by evaporator capacity.
- Oil firing of half the gas turbines matches well with the steam turbine equipment, even when the gas plant is at full production.

GCC PLANT SUBSYSTEM CONTROLS

Gas Turbine Fuel Valve Control

One of the more important features discovered in the control study is that plant pressure control by the gas turbine is difficult to achieve if the pressure drop across the gas turbine fuel valve is too small. In runs not reported here, sustained oscillations of turbine power of 20 second cycle time were observed in attempts to control plant pressure with only 12 psi across the fuel valve (see benchmark run in Volume II). The pressure control loop was easily closed and tuned with 62 psi drop across the valve. The oscillations in power were from zero to almost full load, while the gas production was constant and no oscillations were expected.

Oxygen Plant Response

The gaseous production in the oxygen plant was permitted to change at a rate of 25 percent per hour. This rate is small compared to the rates of change of oxygen demand experienced in this study. Even with an evaporator system designed at one gaseous train capacity and able to move at 10 percent per minute, the supply-demand mismatch is evident in most of these runs. It is clear that the GCC plant can respond to typical load changes and also to large load changes quite adequately in closed-loop operation. But it is also clear that gaseous oxygen plant dynamics do not match corresponding demand changes.

Large oxygen plants have generally been designed for baseload operation and, therefore, are inherently slow in responding to changes in prduction rate. To meet the dynamic operating requirements of GCC power plants, it is clear that oxygen plant design alternatives must be evaluated which provide improved response rates (i.e., greater than 25 percent per hour) according to oxygen supply target rates (page 4-4) recommended above. Among the factors to be considered in such a design study are efficiency, purity, and turndown. One of the most important is controllability.

For example, most oxygen plants are presently designed to maintain high purity with little variation in oxygen concentration. However, it is possible that rapid changes in oxygen production rates may be achieved by relaxing high purity requirements, allowing oxygen concentration to vary over a wider range. This is consistent with the operation of the entrained flow gasifier which does not require oxygen concentration to be held within narrow limits. The feed forward control schemes typically used to maintain oxygen quality may need to be altered.

Ultimately, the effects of oxygen plant response upon the fuel gas composition during typical GCC plant load changes should be studied in more detail.

Control of Sulfur Removal

During the complete set of runs, H_2S removal remained above the 90 percent targeted removal rate, except briefly during contingency operations when the opening of the flare valve interferred with the absorption process. Since the brief periods of non-specification removal occurred simultaneously with flow variations caused by the opening of the flare valve, we believe this problem can be minimized further than demonstrated in this study. Hydrogen sulfide removal rates are presented in the graphic output of each run in Volume II.

Part of the success in sulfur removal is achieved by using a linear relationship between liquid flow and gas flow in the ratio controller at the absorber. From the L/V ratio at the design point as provided by Allied Chemical for the original economic study, we have reduced liquid on a linear schedule with reducing gas flow that would request 60 percent of design liquid flow at zero gas flow.

Since our study did not include COS which is not removed as easily as H_2S, the conclusion of being able to meet the sulfur removal specification of 90 percent must be qualified somewhat. Typically, COS is about 10 percent of the sulfur in the gas, and only about one-third is removed when the absorber is designed to meet the 90 percent sulfur removal level for this type gas. Accordingly, dynamic behavior of the column may permit more COS to pass through the column without being absorbed. However, its total contribution to overall sulfur removal is small. We cautiously state that overall sulfur removal levels under dynamic absorption conditions similar to these runs would approximate the results presented here for H_2S removal.

CO_2 removal is less susceptible to variation in short time periods than H_2S, primarily because it is more soluble in the Selexol solvent than H_2S. During all of the runs, changes in the CO_2 removal rate tended to change the heating value of the clean fuel gas very gradually. Changes on the order of one percent in the LHV of the clean fuel gas were experienced during the course of an entire transient. This change was so small that its impact on the control system was negligible.