4.0 DESIGN CONSIDERATIONS

Steam Cycle

The steam cycle for the Integrated Gasification Combined Cycle plant was modeled on a computer program developed for this project. A simplified diagram of this cycle is shown in Figure 4. The steam turbine is designed for steam inlet conditions of 1250 psia, 950°F. Full load steam turbine output is approximately 37 MW gross. There are two main steam generating systems in the cycle. The HRSG generates steam by recovering heat from the gas turbine exhaust. In parallel with the HRSG, the gasifier recovers heat from the gasification process. The heat is recovered in the gasifier system in the gasifier waterwalls, the syngas cooler and the desulfurization system evaporator bank. The HRSG generates approximately 60 percent of the steam in the cycle. The gasifier/heat exchanger generates the remainder.

The steam leaving the turbine enters a deaerating condenser system. The condensate leaving the condenser system then enters a low pressure feedwater heater. The feedwater leaves the feedwater heater before entering the HRSG at a temperature high enough to avoid acid dew point condensation problems. Approximately 90 percent of the economizer heat absorption is performed in the HRSG while the remaining 10 percent is accomplished in the booster compressor air cooler which is in a circuit parallel with the HRSG. The booster compressor air cooler is used to maintain the air temperature leaving the booster air compressor at 600°F. The majority of the feedwater leaving the economizer is biased between the HRSG steam drum and the gasifier steam drum. The water leaving the booster compressor air cooler is fed to the gasifier steam drum.

The water in the HRSG drum circulates through the evaporator banks in the HRSG and back to the drum through natural convection. The steam/water mixture is separated in the drum. The separated water is combined with the entering feedwater and then feeds the evaporator banks. The separated steam feeds the superheater circuit where it is heated from saturation temperature to 950°F. The HRSG steam outlet temperature is controlled by desuperheating spray water. The HRSG also has auxiliary natural gas fired burners for additional steam generation when required.

The water which feeds the gasifier steam drum is combined with recirculating water and flows though the evaporator circuits in the gasifier and hot gas desulfurization system evaporator and returns to the drum through natural convection. The steam/water mixture is separated in the drum. The separated steam feeds the superheater circuit where it is heated from saturation temperature to 950°F. The gasifier steam temperature control is provided by desuperheating spray water.

Gas Turbine Cycle

For a given gas turbine operating condition, a reduction in gasifier air temperature causes changes to the gasifier operating requirements. The gas turbine still requires the same amount of energy (sensible plus chemical) in the LBG fuel stream to provide the required turbine inlet temperature. If the air feed stream is at a lower temperature, the amount of coal fired in the

Integrated Steam Cycle

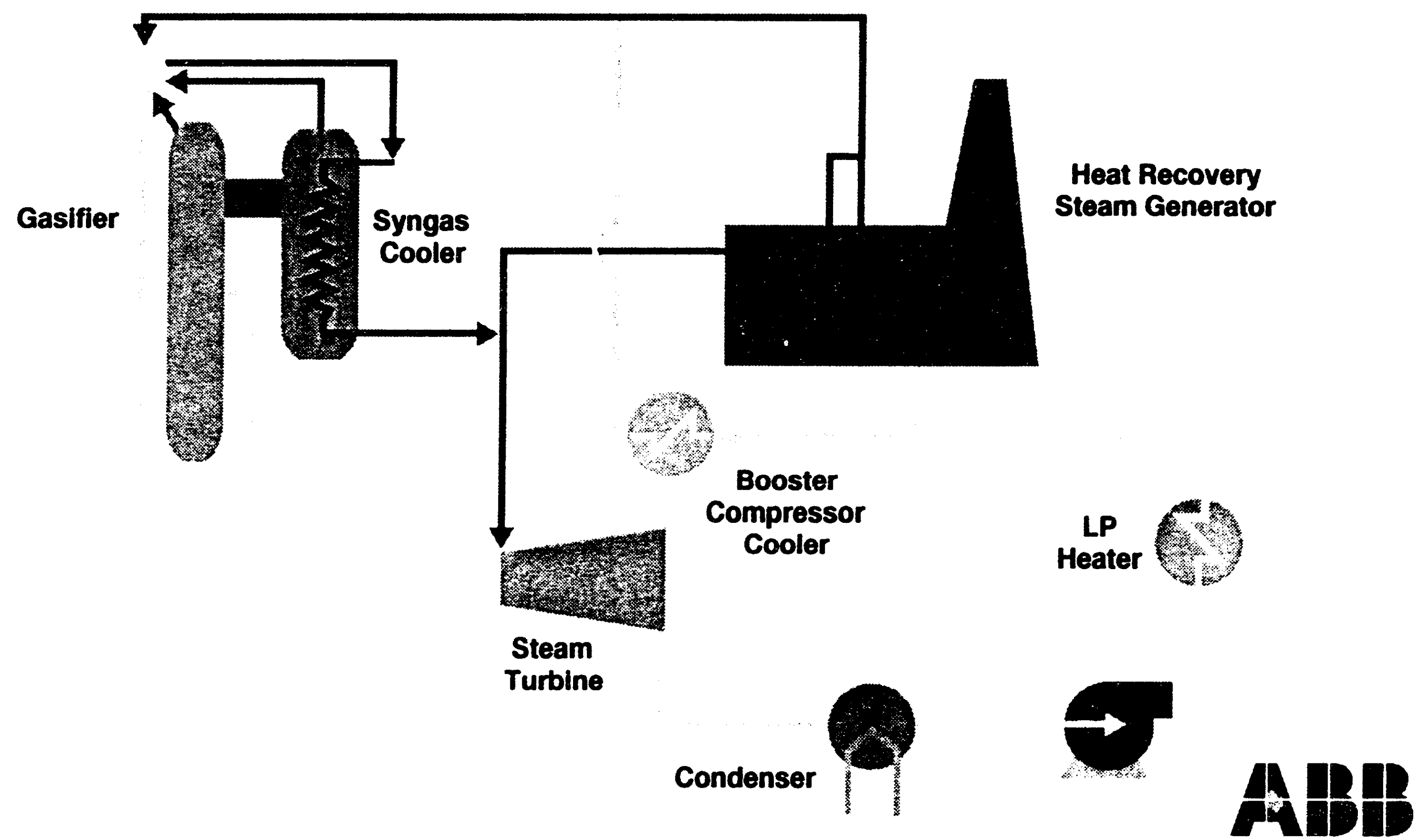


Figure 4

gasifier must be increased to provide the additional energy needed to satisfy the gasifier heat balance. The gasifier stoichiometry would be leaner which would reduce the product gas heating value slightly as gasifier air feed temperature is reduced. The effect on net heat rate favors higher gasifier air temperatures although the effect is not strong. Preliminary studies indicate that reducing the gasifier air temperature from 800 to 500°F degrades the net plant heat rate by 0.7 percent.

Cycle Optimization

For a given stack temperature, the selected feedwater temperature impacts the size of the HRSG economizer bank and the net plant heat rate. As feedwater temperature is raised closer to the stack temperature, the log mean temperature difference for the economizer is lowered and the heat transfer surface area requirement is increased. However, a higher feedwater temperature entering the economizer increases the amount of steam generated by the HRSG. This additional steam generation is partially offset by the additional steam extraction required by the low pressure feedwater heater.

A comparison of feedwater temperatures was performed for the 250°F stack temperature case. The feedwater temperatures that were compared were 200°F and 230°F. The 200°F feedwater temperature, as compared to 230°F, would reduce the amount of main steam generated by about 7,000 pounds per hour. This reduction in steam flow to the turbine causes a corresponding drop in turbine output. The low pressure feedwater heater would require 10,000 pounds per hour less steam extracted from the steam turbine which increases turbine output for the stages after the extraction port. The net effect to the steam turbine is a reduction is steam turbine output of 0.5 MW for the 200°F case as compared to the 230°F case. The result would be a degradation in net plant net rate of 0.9 percent. The design point for the HRSG feedwater temperature was selected to be 230°F.

One of the primary design requirements for this plant is to provide 60 MW net output at 95°F ambient temperature. With the 95°F ambient condition and the gas turbine operating at base load firing conditions, the net plant output is calculated to be approximately 55.6 MW. To obtain an output of 60 MW, various options were investigated.

Peak firing of the gas turbine could provide an additional 8 percent gross output which would satisfy the 60 MW requirement. This would raise the turbine inlet temperatures and improve the net plant heat rate about 1.3 percent as compared to base load firing. However, operation and maintenance requirements would increase and inspection intervals would become more frequent.

Another option to increase plant output is to fire additional fuel in the HRSG (supplemental HRSG firing) to increase the output of the steam turbine. This fuel could be either LBG or natural gas. Thermal efficiency with LBG is 21 percent while thermal efficiency with natural gas is 29 percent. The reason for increased thermal efficiency with supplemental natural gas firing relates to the throttling process which occurs with supplemental LBG firing. When firing LBG in the HRSG, the fraction of LBG which is fired in the HRSG is throttled from high pressure into the HRSG and combusted. The air and coal which was fed into the gasifier to produce this LBG required power to compress. Normally (without supplemental LBG firing) the LBG fuel stream is fed to the gas turbine and combusted. The high temperature and pressure combustion product stream is expanded to less than atmospheric pressure in the gas turbine. CWL&P chose to specify natural gas supplemental firing in the HRSG as the preferred method to obtain 60 MW net output when the ambient rises to 95°F.

Coal/Char Transport Media

Feeding of coal and char into the gasifier is done with lockhopper systems. The gas used for lockhopper pressurization and fluidization must be inert (very low oxygen content) and must be at a pressure high enough to feed the material into the gasifier which is operating at roughly 300 psia. The transport gas should also be low in oxygen content since any oxygen introduced into the reductor zone of the gasifier would consume some of the low btu gas. The fluids which were considered were steam, inerted flue gas from the HRSG or an adjacent boiler or nitrogen.

Utilization of steam would be convenient but would require the coal to be heated to about 500°F to avoid condensing the steam onto the coal particles. However, char is collected at roughly 1000°F and can utilize steam for pressurization and transport. Steam for the char system will be supplied from a turbine extraction or from the gasifier drum steam.

Flue gas from the HRSG could be used if it were inerted by burning off the excess oxygen. The HRSG flue gas is expected to range in oxygen content between 12 and 16 percent by volume depending on turbine load. The coal would still require heating since the flue gas contains significant quantities of water vapor.

Nitrogen can be purchased for this purpose and there are other plant requirements for nitrogen which will exist regardless of the fluid chosen for transport and pressurization. The use of nitrogen does not require that the coal be heated which reduces capital costs. The compression of nitrogen is assumed to be provided by boiling off the required flow rate utilizing a waste heat source to provide this duty. A nitrogen separation plant would be built and operated by the nitrogen vendor on project supplied foundations assuming a minimum nitrogen use and a five year contract. A reliability study showed that transport of coal with nitrogen has been proven and operated reliably at other gasification facilities. Similar precedent for steam is very limited and not encouraging.

The effects of these options on net plant heat rate were investigated in a preliminary study to see if any significant efficiency advantages were apparent between the options. The differences were very small and the selection was done on capital and operating cost differentials. Nitrogen was selected for the coal system and steam was selected for the char system.

Heat Recovery Steam Generator

The HRSG recovers the major fraction of the total heat added to the steam cycle of the plant. The performance design of the HRSG component of this plant was an iterative process. This process involved the consideration of various heat recovery options which were investigated for the gasifier island.

The HRSG is first surfaced as a standard natural gas fired combined cycle HRSG without any supplemental firing. The surface calculations are specified with a 20°F evaporator outlet pinch point temperature difference and a 10°F approach for the economizer. The low pressure feedwater heater is bypassed for this case. The booster compressor air cooler is not operating. The low temperature economizer section is also bypassed.

The maximum amount of supplemental natural gas firing for the HRSG determines the size and location of the auxiliary burners, while the base load case determines the total economizer section surface requirement. The surface required for the low temperature section is calculated by subtracting the high temperature surface requirements determined during natural gas firing from the total economizer surface requirements. This also defines the maximum steam and water pressures during normal operation.

Hot Gas Desulfurization System

General Electric Environment Services, Inc. (GEESI) has been working on the development of a moving bed hot gas desulfurization process since late 1987 with support from DOE. During initial design discussions, it was determined that a fixed bed process configuration would be difficult to control in a reactor sized for a power plant. Two main concerns were the effects of fines and control of the thermochemical reaction. It was felt that it would be more cost effective to dedicate vessels for absorbing and regenerating.

In selecting a sorbent for the process, GEESI looked for a sorbent that had mechanical durability, good regenerability and chemical reactions which took place at the same conditions as the gas leaving the gasifier. A sorbent with chemical reactions occurring near the conditions of the gasifier would allow the overall process to be more thermally efficient. The first sorbent that was used was zinc ferrite. Although this sorbent worked, there was a problem of material degradation. For this reason, the sorbent was changed to zinc titanate. Zinc titanate has less reduction in sulfur capture ability after repeated cycles of sulfidation and regeneration. The zinc titanate has virtually no zinc loss in the highly reducing coal gas and a higher attrition resistance. It is GEESI's opinion that this sorbent is more compatible with entrained flow gasifiers in both oxygen and air blown operation.

From testing in the pilot unit, it was determined that there is a need to remove chlorides from the gas to prevent fouling of the downstream heat exchangers by Zinc Chloride and to minimize loss of catalyst. GEESI is proposing a sodium bicarbonate injection system to accomplish this. This system would inject sodium bicarbonate into the gas stream prior to the gas entering the absorber.

5.0 OPERATIONS AND MAINTENANCE

The operations and maintenance budget was developed with input from the personnel of Duke Engineering & Services, Duke/Fluor Daniel Operations, ABB CE, ABB-CSSI and CWL&P Operations. Plant layout, equipment specifications, vendor quotations, process descriptions, P&ID's, PFD's and the Project Design Questionnaire were reviewed and the basis for the budget was established. The major assumptions are as follows:

- Costs are for a 60-month operating period commencing with start up of commercial operation and including certain costs that would be incurred during the commissioning period.

- Operations personnel would begin their involvement up to 20 months preceding the commercial operations date. Union labor rates and fringe benefits reflect those currently in effect at CWL&P, with escalation applied to the years of incurred cost.

- Unit costs for fuel and utilities are as stated in the Project Design Questionnaire.

- Plant capacity factors utilized during each year of operation coincide with the BACT document: Year 1 - 30% (2,630 hrs/yr), Year 2 - 50% (4,383 hrs/yr), Year 3,4,5 - 80% (7,013 hrs/yr)

- Natural gas was utilized for turbine peaking operation, limited at 1000 hours per year per the BACT assessment.

- Ash (slag) disposal would be in the existing CWL&P ash pond. Estimates for offsite disposal have been identified.

- Electrical auxiliary power usage , while quantities have been established, have not been included in the O&M cost estimate.

- Existing CWL&P wastewater treatment facilities will be utilized.

<u>Plant Staffing</u>

Mobilization of operations personnel was planned to begin 20 months prior to commercial operations and full staffing reached 4 months before commercial operation.

For estimating purposes, the project staffing level (67 people) is considered a "stand alone" facility. Costs for plant support services (human resource functions, accounting, procurement, etc.) have been included.

6.0 COST ESTIMATE

In arriving at the detailed cost estimate for this project the combined technical and commercial expertise from both Duke Engineering and Services and ABB CE were utilized.

Detailed engineering selections and drawings were produced for all major components, systems and sub-systems to facilitate optimum price development both internally and externally.

Firm price quotations were requested from a minimum of three vendors for each major piece of equipment which make up the entire plant scope. These quotations were reviewed in detail by ABB CE and DE&S for technical and commercial completeness.

Takeoffs from contract quality drawings were made to quantify interstage piping, instrumentation, valving, power and control wiring, conduit, platforms, walkways, building siding, support structures, concrete work, insulation and lagging.

Heavy structural steel fabricators were involved in the pricing of the major components of the gasification plant (e.g. gasifier, heat exchanger pressure vessels, steam drum, coal and char receiving bins/lockhoppers, steam turbine, heat recovery steam generator, etc.) to ensure current labor and material costs, and that optimum designs were reflected in the pricing.

Vendor and in-house cost databases were examined with respect to determining pricing relevance to similar designs/materials selection criteria.

Construction Labor costs to dismantle existing equipment and erect the new systems/components were based on single shift straight time, 40 hour week and local union labor composite costs. The optimum nature of the total construction price reflects the merging of the quality of the ABB CE discrete design and drawing data to the construction and O&M estimating expertise of Duke Engineering and Services. Facilitating the completeness and accuracy of the total construction price was the rather comprehensive analysis of the local site labor conditions.

7.0 Conclusions

The preliminary design of the ABB CE IGCC Repowering Project has been completed and a cost estimate generated. The preliminary design demonstrates that the air-blown, pressurized, entrained flow gasification process is viable for power generation applications. The cost estimate is for an entire stand alone plant with the added complexity of renovating the existing building and maintaining the existing coal fired boilers on-line. The costs were higher than originally expected but the scope of work and the complexity of construction also exceeded the original expectations.

The major plant performance requirements which impacted design were:

- Plant output of 60 MW net at 95°F ambient temperature
- 1265 psia, 950°F steam conditions
- Gas turbine loads from 30 to 100 percent
- Ambient temperature range from 0 to 95°F
- Gasifier performance in both normal and high performance mode
- Steam cycle performance with gasifier not operating and gas turbine firing natural gas

There are several reasons for these results and the cost figures should not be construed as the final cost of an air-blown, entrained flow coal gasification system. The reasons include such factors as system capacity, site limitations, complexity of the preliminary design and first of a kind systems. The capacity, 60 MW net, is small for a utility power plant and contribute to the high cost since many fixed costs that are associated with engineering a plant would be the same for a much larger size plant. Therefore, a larger plant would yield a lower cost per kilowatt. Similarly, the fact that this project is being designed as a first of a kind plant with many systems being designed from scratch adds cost. The site requirements affected the design of the plant which in turn affected the cost. The site requirements and extended scope also added costs which are not normally considered in a commercial plant. Especially with respect to those added costs for:

- Supplying and erecting the natural gas supply line into the site;
- Re-constructing the abandoned rail line(s) into the site;
- Utilizing the existing boiler building
- Inability to use existing steam turbine
- Incorporating a steam turbine bypass
- Electrical transmission equipment/switchgear beyond the primary terminals of the transformer.
- Dismantling and re-arrangement costs associated with integrating the <u>new</u> systems/components with the existing systems/components.

Commercializing this technology will require that a demonstration facility be constructed. A new site needs to be found where significant portions of the plant can be reused without incurring expensive reconstruction and renovation. The customer should be planning to use the unit as a baseload unit and not as a peaking unit for part time operation. The hot gas desulfurization system and the hot particulate filter system are critical to the success of this technology and need to be developed independent of this project. Fuel and char feed systems which are more cost and space efficient need continued investigation.

PIÑON PINE IGCC PROJECT STATUS

AUGUST 1993

E. B. Higginbotham
Sierra Pacific Power Company
6100 Neil Road
Reno, Nevada 89520-0400

L. J. Lamarre
Foster Wheeler USA Corporation
Perryville Corporate Park
Clinton, NJ 08809

M. Glazer
The M. W. Kellogg Company
601 Jefferson Avenue
Houston, TX USA 77210

ABSTRACT

Sierra Pacific Power Company (SPPCo) intends to build the Piñon Pine Power Project, an integrated coal gasification combined cycle (IGCC) plant at its Tracy Power Station near Reno, Nevada. The plant will burn approximately 800 tons of coal per day to generate electricity in a base load application. The Piñon Project was selected by the U.S. Department of Energy (DOE) for funding under Round IV of the Clean Coal Technology Program. The project will demonstrate the use of the KRW

agglomerating fluidized bed gasifier operating in the air blown mode. Hot gas cleanup consisting of particulate and sulfur removal will also be demonstrated.

The Cooperative Agreement between SPPCo and the DOE was executed in August 1992. Foster Wheeler USA Corporation (FWUSA) will provide engineering and construction management services. The M. W. Kellogg Company (MWK) will provide engineering of the gasifier and hot gas cleanup systems.

A discussion of project progress since the 1992 Clean Coal Technology Conference, design and economic considerations, and current project status is presented.

NOTICE

INTRODUCTION

In response to DOE issuing its Program Opportunity Notice for Round IV of the Clean Coal Technology program, SPPCo submitted a proposal requesting co-funding of the Piñon Pine Power Project. This proposal was selected for co-funding by the DOE and a Cooperative Agreement between the DOE and SPPCo was executed in August 1992. SPPCo's proposal was for the design, engineering, construction, and operation of a nominal 800 ton-per-day (80 MW net), air-blown integrated gasification combined cycle (IGCC) project to be constructed at SPPCo's existing Tracy Station, a 244 MW, gas/oil-fired power generation facility located on a rural 724-acre plot about 20 miles east of Reno (see Figure 1). SPPCo will own and operate the demonstration plant, which will provide power to the electric grid to meet its customer needs.

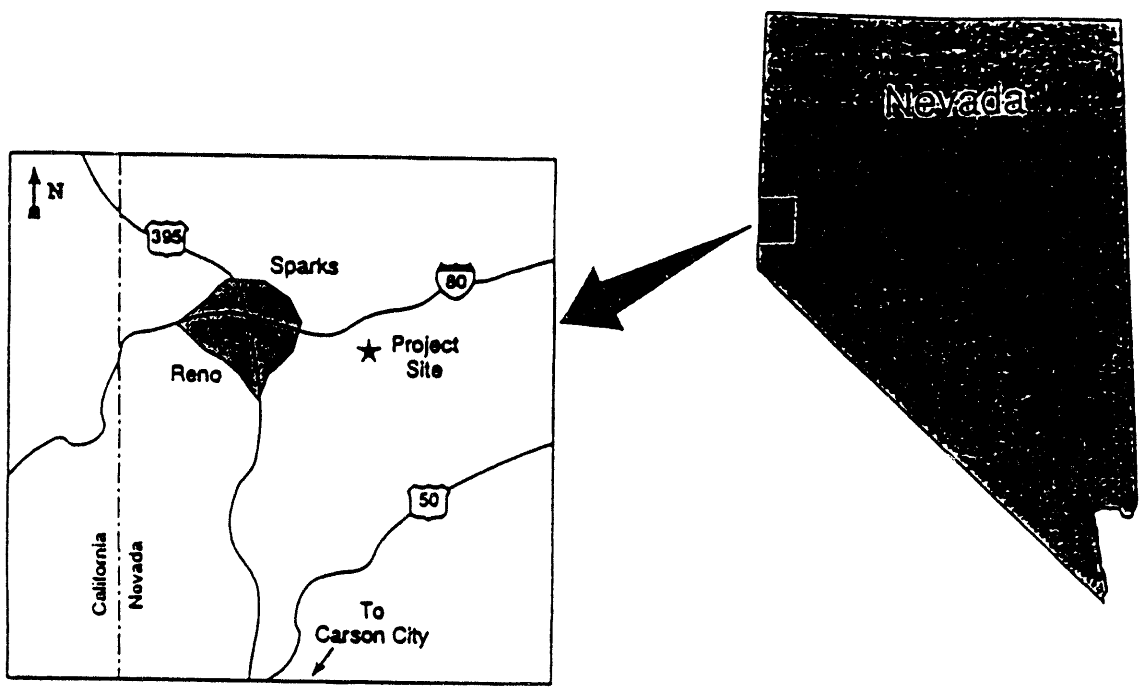


Figure 1. Location of Piñon Pine Power Project.

The KRW agglomerating fluidized bed gasifier will be the basis for the Piñon project. This gasifier, operating in the air blown mode, will provide a low heating value fuel gas to be used to fire a combustion turbine. High temperature exhaust from the combustion turbine will then supply the energy required to generate steam in a heat recovery steam generator (HRSG) for use in a steam turbine. Both the combustion turbine and the steam turbine will drive generators to supply electricity to the electric power grid.

The KRW gasifier uses an in bed sulfur sorbent. This sorbent also moderates the process temperature in the gasifier and suppresses ammonia formation in the fuel gas.

The project is based on using limestone for in-bed desulfurization. Hot fuel gas cleanup will consist of particulate and sulfur removal. Ceramic candle or similar barrier filters will be used for particulate removal. A regenerable mixed metal oxide sorbent in a fixed bed reactor will be used for removal of remaining sulfur in the fuel gas. The sulfur removal sorbent originally planned to be used was zinc ferrite.

The current project has changed during the past year reflecting changes one would expect from evolving technology. A new combustion turbine utilizing 2350ºF firing temperature has been selected. This combustion turbine, the General Electric MS6001FA, improves the plant efficiency and the plant capacity. Cycle design, originally based on zinc ferrite sorbent has evolved and is currently based on the use of other zinc based mixed metal oxide sorbents. These sorbents do not require steam for process temperature suppression as zinc ferrite requires, and have shown better regeneration characteristics than zinc ferrite. Further changes might be expected in the design of the hot gas cleanup system.

The project is currently scheduled to begin start-up in 1996 with operation on coal by the end of the year. To accomplish this, SPPCo has contracted with Foster Wheeler USA Corporation (FWUSA) for the engineering, procurement and construction management of the project. FWUSA in turn has subcontracted with The M. W. Kellogg Company for engineering and other services related to the gasifier island. Figure 2 depicts the project organization.

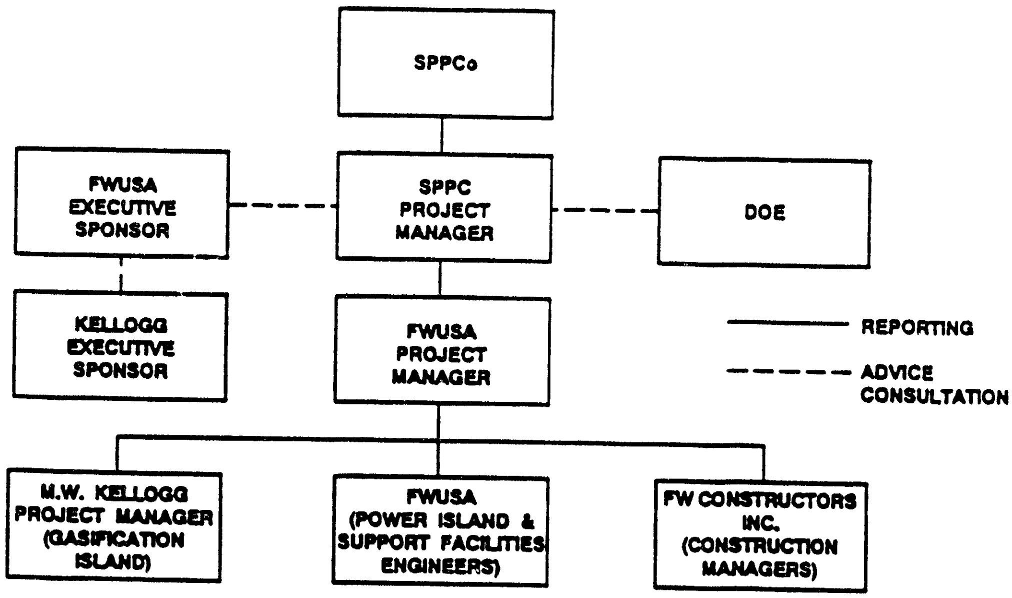


Figure 2. Project Organization Chart.

PROJECT GOALS

SPPCo's goals for the Piñon project are several:

- Piñon must be a least cost generation option.
- Piñon must allow fuel diversification.
- Piñon must conserve water resources.
- Piñon must not be a detriment to the environment.

SPPCo has not added generating capacity or transmission capacity since 1985. System sales have been increasing at an annual rate of 5% over the last ten years. Future load growth is expected to continue at a 4% annual growth rate. The result is the need to add base load generation, peaking generation, and transmission capacity in the near future. The Piñon project will provide a portion of SPPCo's base load generation needs.

SPPCo conducts its own resource planning to meet its customer's needs for electricity. In addition, the State of Nevada requires that utilities prepare and submit their "Resource Plan" to the Public Service Commission of Nevada (PSCN) for review and concurrence. A least cost plan for meeting customer needs is proposed. This plan is based on load growth projections, supply-side and demand-side options, and consideration of other factors such as fuel mix, environmental effects, and financial constraints. SPPCo's resource plan is undergoing PSCN review at this time. The Piñon project is included as a least cost generation option with the added benefits of fuel flexibility and environmental acceptance.

The Piñon project is designed to produce low Btu gas from coal. The coal used for the design basis is a Utah bituminous coal available from a number of suppliers. For start up and as an alternate fuel, either natural gas or propane may be used. The three fuel capability significantly reduces reliability concerns coming from the developmental aspects of the coal gasification and hot gas cleanup processes.

The arid climate of Nevada and its recent six year drought require that new generation sources be designed to minimize water consumption. A combined cycle plant will use less water than a conventional steam plant simply because its heat rejection requirements are less. An economic and technical evaluation of plant cooling options will decide the method of cooling employed. Reclaiming water from waste streams such as boiler and cooling tower blow-down streams will be considered in the project design.

SPPCo and its management have stressed their commitment toward protecting the environment. Emissions from Piñon will be among the lowest of any coal-fired plant and significantly less than any pulverized coal-fired plant. As a base load unit, any generation it displaces will result in a net improvement in system wide emissions.

PROJECT DESCRIPTION

Technical Overview of Process

Raw coal will be received at the plant in weekly unit trains consisting of 100-ton automated bottom dumping railcars. Once unloaded, coal will be stored and transported within enclosures to minimize dust emissions. The coal is received and stored as 2" x 0 and is then transferred to a preparation area where it is crushed, dried, sized and passed to a day-bin for feeding the gasifier island. Sized limestone and dried coke breeze (for startup) are received by covered truck and are also stored in silos close to the gasifier island.

The two major components of the plant are the gasification island and the power island. Figure 3 is a block diagram of the processes to be employed in the Piñon project.

In the gasification island, crushed and sized coal and limestone are metered through lockhoppers and fed pneumatically through a central feed tube in the bottom of the gasifier. The temperature of the bed is controlled by metering the air and steam into the gasifier's central jet. The coal/limestone bed is maintained in a fluidized state in the gasifier via gas recirculation. Partial combustion of char (devolatilized coal) and gas occurs within the bed to provide the heat necessary for the endothermic reactions of devolatilization, gasification, calcination, and desulfurization. Ash and spent limestone are removed from the bottom of the bed. A diagram of the KRW gasifier is shown in Figure 4.

Coal gas leaving the gasifier passes through a cyclone to remove the majority of the particulate matter that is returned to the fluidized bed. The gas leaving the gasifier is cooled to 900-1100ºF before entering the hot gas cleanup section. Ceramic candle filters or similar barrier filters remove essentially all the remaining particulate material prior to the clean gas entering the sulfur sorbent bed. In the desulfurizing reactors, nearly all the remaining sulfur compounds are removed in a fixed bed of zinc based mixed metal oxide sorbent. The sorbent is subsequently regenerated with nitrogen diluted dry air. This process sends the regeneration gas stream to the sulfator where the sulfur oxides react with additional or fresh lime and air to form calcium sulfate, which exits the system along with the coal ash in a form suitable for landfill, or potentially to be used as a commercial byproduct.

The clean coal gas will be delivered to a General Electric MS6001FA combustion turbine/generator which will produce approximately 61MW on this fuel. This combustion turbine is also designed to fire either natural gas or propane and blends of these fuels with coal gas.

The MS6001FA is a new machine offering a high firing temperature (2350ºF) and a high exhaust temperature (1100-1125ºF) making it very efficient in combined cycle operation. Exhaust gas from the combustion turbine is used to generate steam in a heat recovery steam generator (HRSG). Steam generated in the HRSG and the gasifier process are combined and superheated in the HRSG. Current heat balances are based on a 900ºF /900psig steam cycle. With this steam cycle, a steam turbine/generator producing approximately 40MW will be used. With the 1100ºF combustion turbine exhaust, evaluation of higher temperature and pressure steam cycles will be performed. A further improvement in capacity and efficiency is expected.

As efficiency has improved, water consumption per unit generation is reduced. This is due to reduced evaporation losses from lower heat rejection requirements. In addition, blow-down streams will be evaluated for water treatment and re-use, further reducing plant water consumption.

Plant Performance

Based on using the 900ºF/900psig steam cycle, the Piñon project will be 15-20% more efficient than SPPCo's current coal-fired units. The expected performance is summarized in Tables 1 and 2 below. This represents a significant improvement in SPPCo's system heat rate. Using coal fuel and its demonstrated price stability relative to other fuels, Piñon will deliver least cost generation to SPPCo's customers.

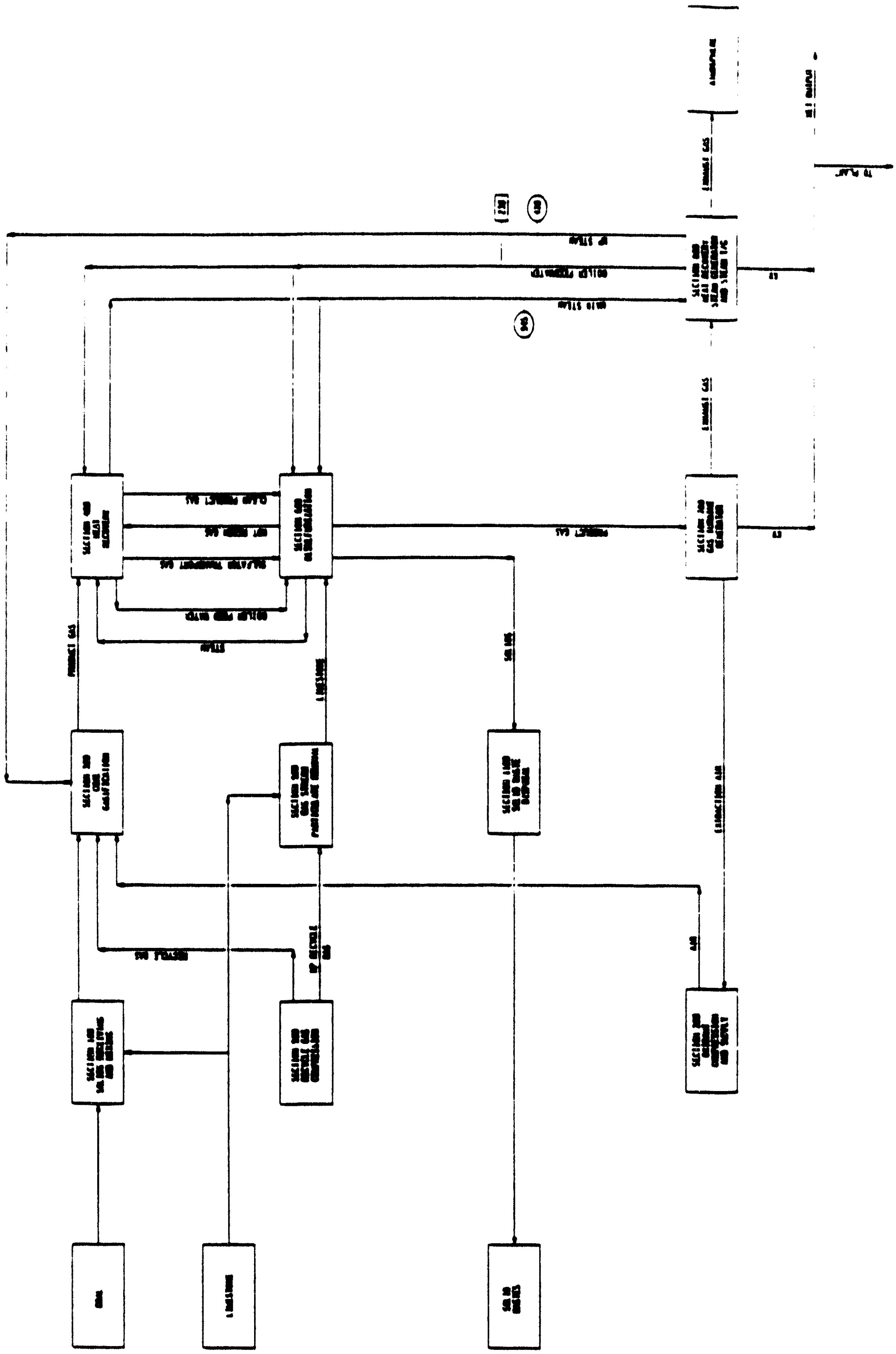


Figure 3. Process Flow Diagram.

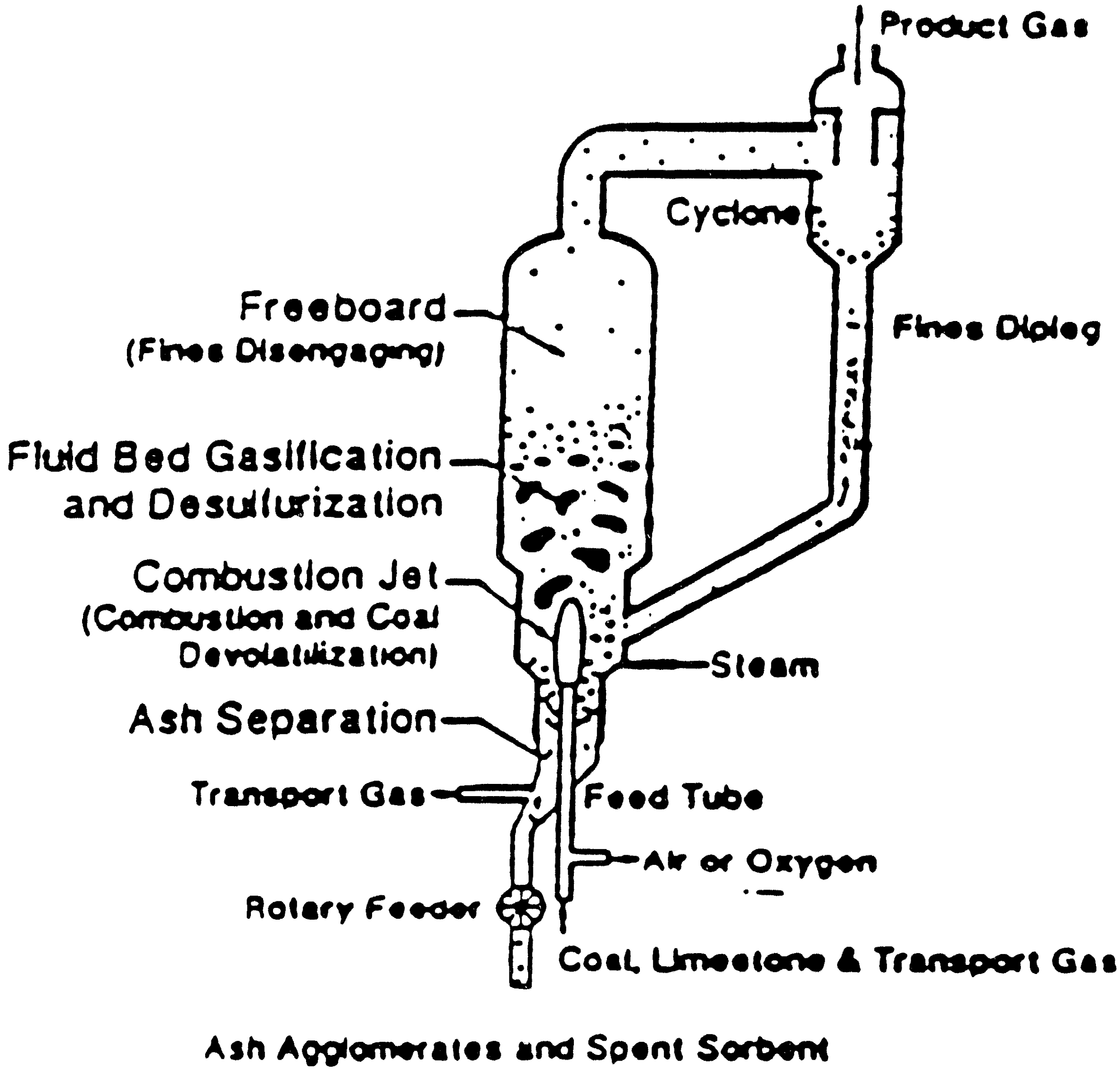


Figure 4. KRW Gasifier.

Expected Plant Performance*	
Heat Input (10^6BTU/Hr)	805
Combustion Turbine Power (MW)	61
Steam Turbine Power (MW)	40
Steam Turbine Conditions (psia/°F)	900/900
Station Load (MW)	6
Net Power Output (MW)	95
Heat Rate (BTU/kWh)	8470

*At 50ºF and 4280' elevation, evaporative cooler off.

Table 1. Expected Plant Performance

Expected Performance vs. Temperature			
Ambient Temperature	**25ºF**	**50ºF**	**95ºF**
Expected Performance - Coal			
Net Power Output MW	95	95	90
Heat Rate Btu/kWh (HHV)	8470	8470	8554
Expected Performance - Natural Gas			
Net Power Output MW	91	88	84
Heat Rate Btu/kWh (HHV)	8103	8144	8207

Table 2. Expected Performance vs. Temperature

Plant Layout

Integration of the Piñon project into the existing Tracy plant is shown conceptually in Figure 5. Piñon will be located west of Tracy Unit 3. Control of the Piñon facility will be through the control room of Unit 3 which will be modified to include Piñon's distributed control system. The Unit 3 crane rails will be extended to service the combustion and steam turbines of the Piñon plant. The existing rail spur used for oil delivery will be extended and will be used for coal delivery and unloading. The Piñon switchyard will be integrated into the existing Tracy plant switchyard.

PROJECT STATUS, SCHEDULE, AND BUDGET

The schedule for the Piñon project is shown in Figure 6. Project activities to date have primarily been in permitting and preliminary design. Prior to the start of construction several key regulatory and permitting items must be completed.

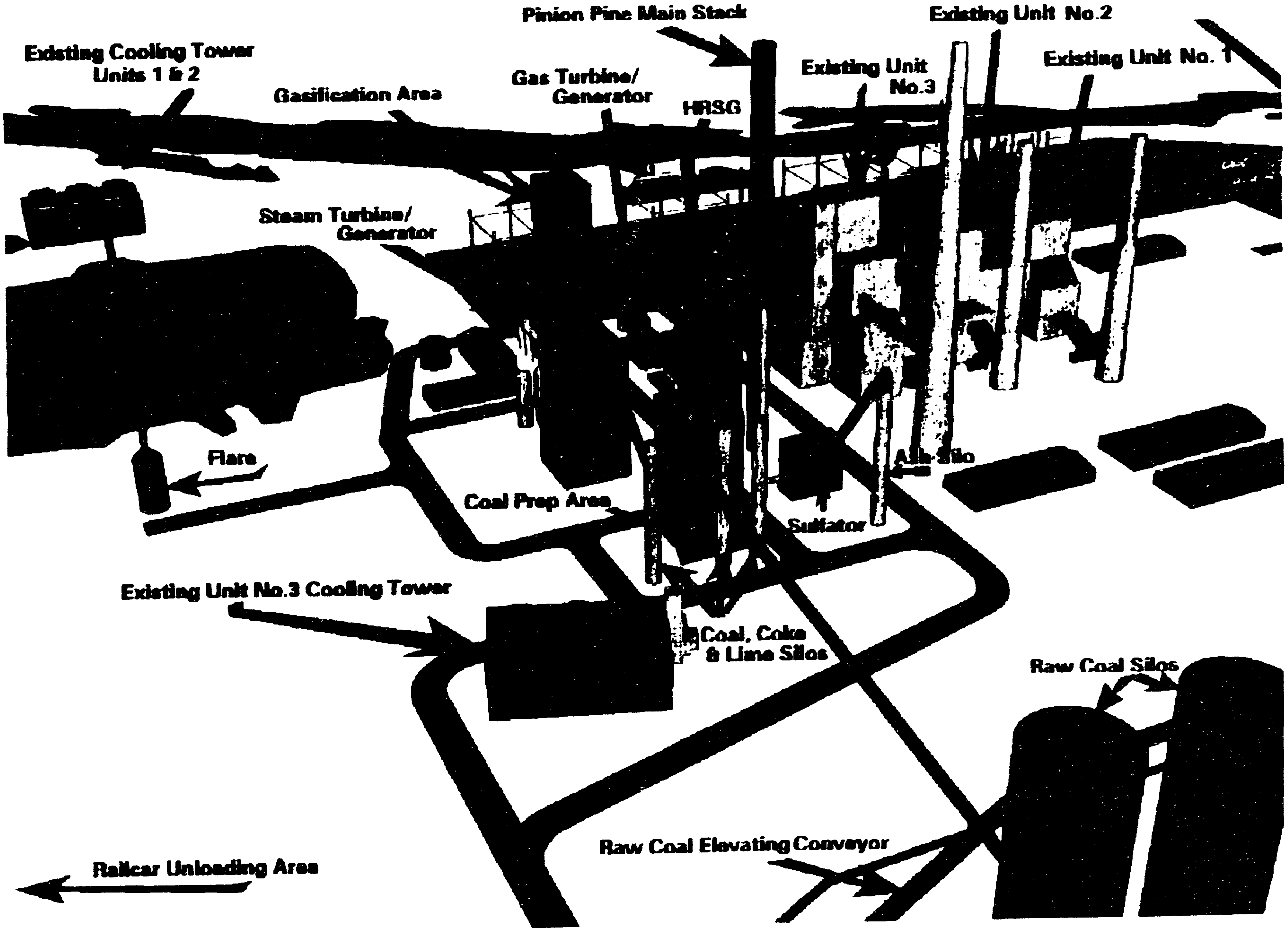


Figure 5. Plant Layout

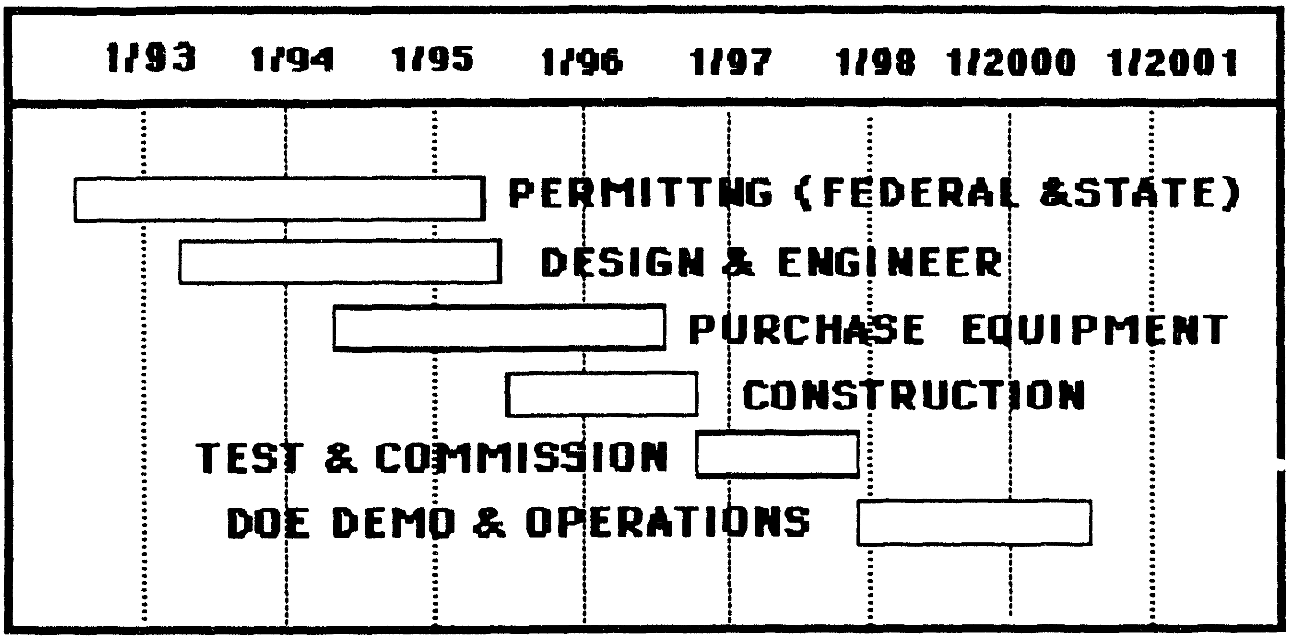


Figure 6. Schedule for Piñon project.

<u>Resource Plan</u>

The 1992 Electric Resource Plan was submitted to the PSCN July 1, 1992. Hearings on this plan were held. The decision from the hearings requested that SPPCo continue with the project, subject to review in a Revised Resource Plan to be filed April 1, 1993. Preliminary design of the Piñon project has been continuing. Continued design efforts have resulted in improvements in capacity, efficiency, and cost. The improvements are shown in Table 3.

	1992 Filing	1993 Re-Filing
Net Power (MW)	77	95
Heat Rate (Btu/kWH, HHV)	8900	8470
Cost per kW (1992 $) (SPPCo portion after cost sharing)	1090	978

Table 3. Comparison of Resource Plan Filings

Hearings on the revised resource plan are in progress with a decision expected in September 1993. With the improved performance and cost, Piñon remains a least cost option for base load coal-fired power supply.

NEPA/EIS

Federal funding of the Piñon project automatically invokes environmental review under the National Environmental Policy Act (NEPA). A determination has been made that an Environmental Impact Statement (EIS) is the appropriate level of documentation for the NEPA review. The DOE is the lead agency for the NEPA reviews. Under contract to SPPCo., EBASCO Environmental has been assisting the environmental engineering and analysis during the NEPA review by the DOE. The scheduled date for the Record of Decision is March 31, 1994. Funding for Phase II of the project, Procurement, Construction and Start-up is, contingent on receiving a favorable Record of Decision.

UEPA Process

The Utility Environmental Protection Act (UEPA) requires that SPPCo apply for a permit for construction. This application must address the following areas:

- Need for the project.
- An analysis of project alternatives.
- An assessment of environmental impacts.
- Proposed mitigation measures to reduce or eliminate environmental disturbance.
- Description of the project and its facilities.

The UEPA application is filed with the Public Service Commission of Nevada. On completion of a public review period and after all necessary construction, operating, and special use permits have been obtained, the PSCN will issue a Permit to Construct the Piñon Pine project.

Design

Project design has been ongoing since the execution of the Cooperative Agreement, August 1, 1992. Preliminary design work has been in support of permitting activities and selection of key equipment process items. Specifically, selection of the combustion turbine and the sulfur sorbent for the hot gas cleanup section have allowed preliminary process design to accelerate. The combustion turbine selection dictates the plant capacity and balance of plant design. Selection of the sorbent, primarily due to process steam requirements of particular sorbents, was required in order to proceed with the design of the steam cycle.

Construction and Start-Up

Construction is scheduled to be completed in the Fall of 1996. Plant start-up will be on natural gas fuel. Following mechanical completion of the gasifier, operation on low Btu gas from coal is expected by December 1996.

Demonstration

Project demonstration will continue through July 2000. During this period, the KRW gasifier operating in the air blown mode will be demonstrated. Also, hot gas cleanup employing particulate filtration and sulfur removal will be demonstrated. Operation of the plant will be demonstrated on low sulfur western coal. Operating data on higher sulfur eastern coal will also be obtained during the demonstration phase.

Project Budget

The project is expected to cost approximately $270 million through its completion with approximately half of the funds coming from the DOE. In addition to capital costs; operating expenses, maintenance expenses, and fuel costs will also be shared by SPPCo and the DOE during the start-up and demonstration phases of the plant operation.

THE WABASH RIVER COAL GASIFICATION REPOWERING PROJECT PROGRAM UPDATE

Phil Amick
Project Manager
Destec Engineering, Inc.
Houston, Texas

Jim Cook
Project Director
PSI Energy, Inc.
Plainfield, Indiana

ABSTRACT

PSI Energy, Inc. and Destec Energy, Inc., are participating in the Department of Energy (DOE) Clean Coal Technology Program to demonstrate coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments ("CAAA"). A Clean Coal Round IV selection, the project will demonstrate integration of the existing station steam turbine generator and auxiliaries, the new combustion turbine generator, heat recovery steam generator tandem and the coal gasification facilities to achieve improved efficiency and reduced installation costs.

The Wabash Project achieved several significant milestones in the second quarter of 1993, including certification by the Indiana Utility Regulatory Commission, and receipt of the air permit from the Indiana Department of Environmental Management. The Department of Energy completed the Environmental Assessment in this period as well, and issued a Finding-of-No-Significant-Impact for the Wabash Project.

Construction of project facilities began in the third quarter of 1993. Upon completion in 1995, the project will not only represent the largest coal gasification combined cycle (CGCC) power plant in operation in the United States but will also emit lower emissions than other high sulfur

coal fired power plants and improve the heat rate of the repowered unit by approximately twenty percent.

INTRODUCTION

The Wabash River Coal Gasification Repowering Project (Wabash Project) is a joint venture of Destec Energy, Inc., (Destec) of Houston, Texas and PSI Energy, Inc. (PSI) of Plainfield, Indiana, who will jointly develop the coal gasification combined cycle (CGCC) power plant. PSI will be responsible for the new power generation facilities and the modification of the existing unit, and Destec will be responsible for the coal gasification plant.

Destec's coal gasification technology will be used to repower one of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The CGCC power plant will produce a nominal 262 net MW of clean, energy efficient capacity for PSI's customers. In the repowered configuration, PSI and its customers may additionally benefit because of the role the Wabash Project plays in PSI's compliance under the CAAA regulations. The CGCC plant will dispatch for base load in PSI's system on the basis of both efficiency and environmental emissions. The project will use locally mined, high sulfur coal.

BACKGROUND

The Destec Coal Gasification process was originally developed by the Dow Chemical Company during the 1970's in order to diversify its fuel base from natural gas to lignite and other coal. The technology being used at Wabash is an extension of the experience gained from that time through pilot plants and up to the Louisiana Gasification Technology, Inc. (LGTI) facility in Plaquemine, Louisiana, a 160 MW coal gasification facility which has been operating since April 1987.

Sargent & Lundy will provide engineering services to PSI for the design and procurement of the modifications to the existing station and the new power block equipment, and will provide the system integration interface to Destec. PSI will manage the construction of, own and operate the power generation facilities. Destec will manage the construction of, own and operate the coal gasification and air separation facilities. Dow Engineering Company, previously engineer for the LGTI facility, will provide engineering services to Destec for the gasification plant. Liquid Air Engineering Corporation has received a turnkey contract for the air separation plant.

The major provisions of the agreements establishing the PSI and Destec relationship are:

PSI

- to own and operate the power generation facility
- to build the power generation facility to an agreed common schedule
- to furnish Destec with a site, coal, power and services
- to provide stormwater and wastewater facilities .

DESTEC

- to own and operate the coal gasification facility
- to build the gasification facility to an agreed, common schedule
- to guarantee performance of the coal gasification facility
- to meet environmental conditions
- to deliver syngas and steam to the power generation facility

The structure of the Gasification Services Agreement which defines these provisions allows the Power Generation Facility and the Coal Gasification Facility to be integrated for high efficiency.

FACILITIES INTEGRATION

The site of the project is PSI Energy's Wabash River Generating Station, located near Terre Haute, Indiana. Only Unit 1 of the six existing units will be repowered as part of the project. The existing pulverized coal fired boiler will be decommissioned and the steam turbine, a Westinghouse reheat unit originally placed in service in 1953, will be driven by steam from the new facilities. Other existing facilities to be used by the project include the railroad, coal unloading facilities, and the ash pond, in addition to the existing steam turbine generator auxiliaries, condenser and substation. No new construction will be required within the existing boiler and turbine buildings except for the steam piping interconnection.

New construction will take place in two areas (Figure 1). A 15 acre plot containing the gasification island, oxygen plant, water treatment and gas turbine-heat recovery steam generator block is on a hill overlooking the existing station. The new wastewater and storm water ponds will be located nearby in an area previously used as an ash pond. Coal for the Wabash Project, a high sulfur midwestern bituminous, will be stored separately from the compliance coal that will be burned in Units 2 through 6 of the existing station. Existing coal unloading facilities will be shared, with the remainder of the coal handling equipment being part of the new installation.

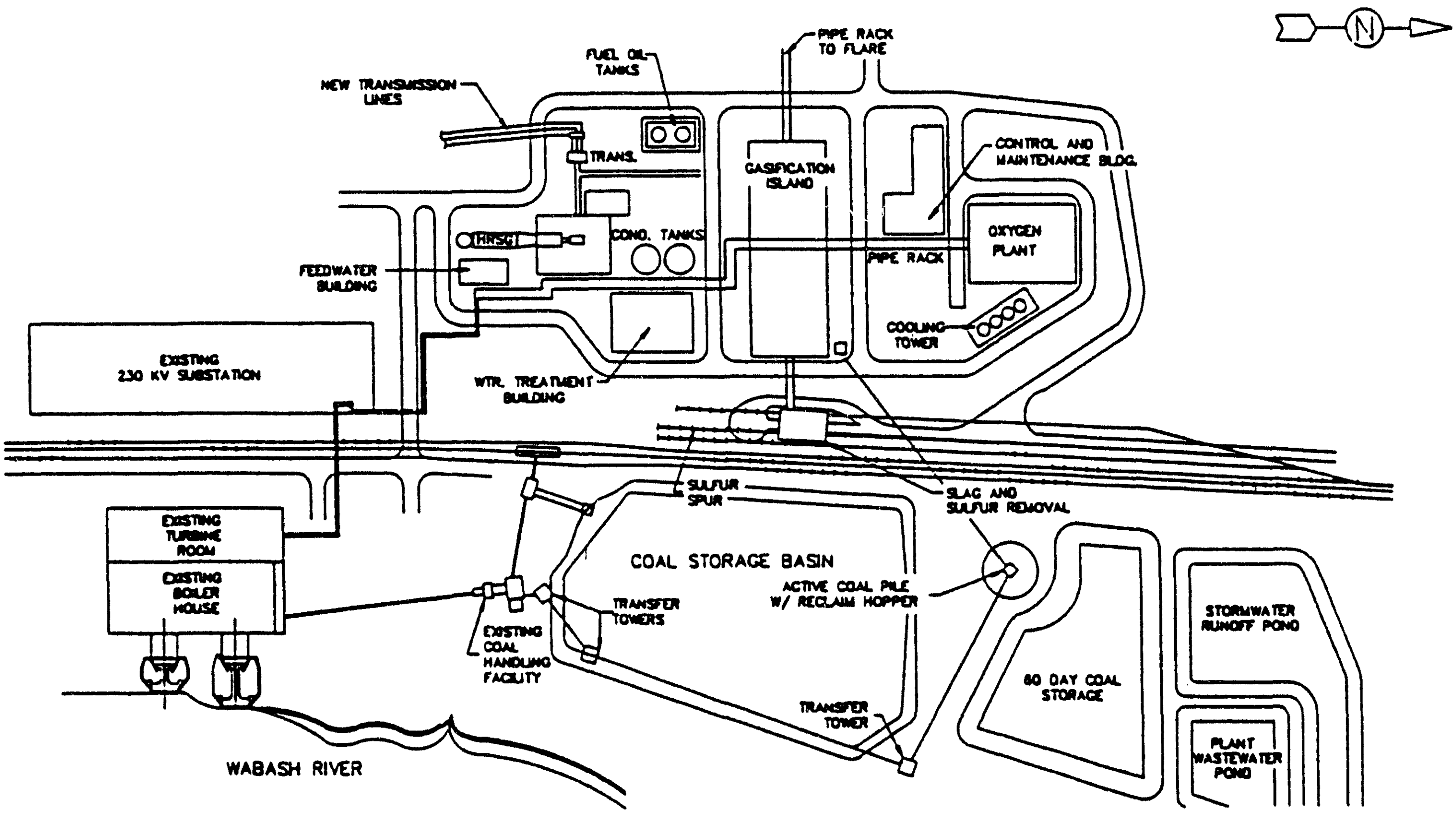


Figure 1 - Site Plan

New facilities for the project are listed below. Destec and PSI will independently design, procure equipment and construct their respective portions of the Wabash Project. However, cooperation in design efforts and integration of systems has allowed the participants to reduce costs by minimizing redundant systems and maximizing efficiency by thermal integration.

PSI:

- Combustion turbine
- Heat recovery steam generator
- Modifications to coal handling
- Oil storage tanks
- Piping additions
- Water treatment facilities
- Control room and buildings
- Modifications to steam turbine

DESTEC:

- Slurry preparation
- Gasification and heat recovery
- Slag removal
- Gas cleanup
- Sulfur recovery
- Oxygen plant
- Control, administration & maintenance building

Repowering the existing unit, and utilizing the existing site facilities mentioned above, in addition to the existing steam turbine generator, auxiliaries, and electrical interconnections, represent an installed cost savings of approximately $30 to $40 million as opposed to an entirely new, greenfield installation.

THERMAL INTEGRATION

The Destec gasification process features an oxygen-blown, two stage entrained flow gasifier. The synthetic fuel gas (syngas) is piped to a General Electric MS 7001F high temperature combustion turbine generator. A heat recovery steam generator (HRSG) recovers gas turbine exhaust heat. In the gasification process, coal is ground with water to form a slurry. It is then pumped into a gasification vessel where oxygen is added to form a hot raw gas through partial combustion. Most of the non-carbon material in the coal melts and flows out the bottom of the vessel forming slag - a black, glassy, non-leaching, sand-like material. Particulates, sulfur and other impurities are removed from the gas before combustion to make it acceptable fuel for the gas turbine. Sulfur is removed from the syngas using conventional "cold" gas clean-up systems similar to those used in crude oil refineries around the world. Some of these systems must operate at near ambient gas temperatures, necessitating the reduction of the syngas temperature by heat exchange to other streams. Condensate, feedwater and steam streams are exchanged between the gasification island and the power block HRSG to maximize efficiency by making the best use of lower levels of heat available in each area. (See Figure 2).

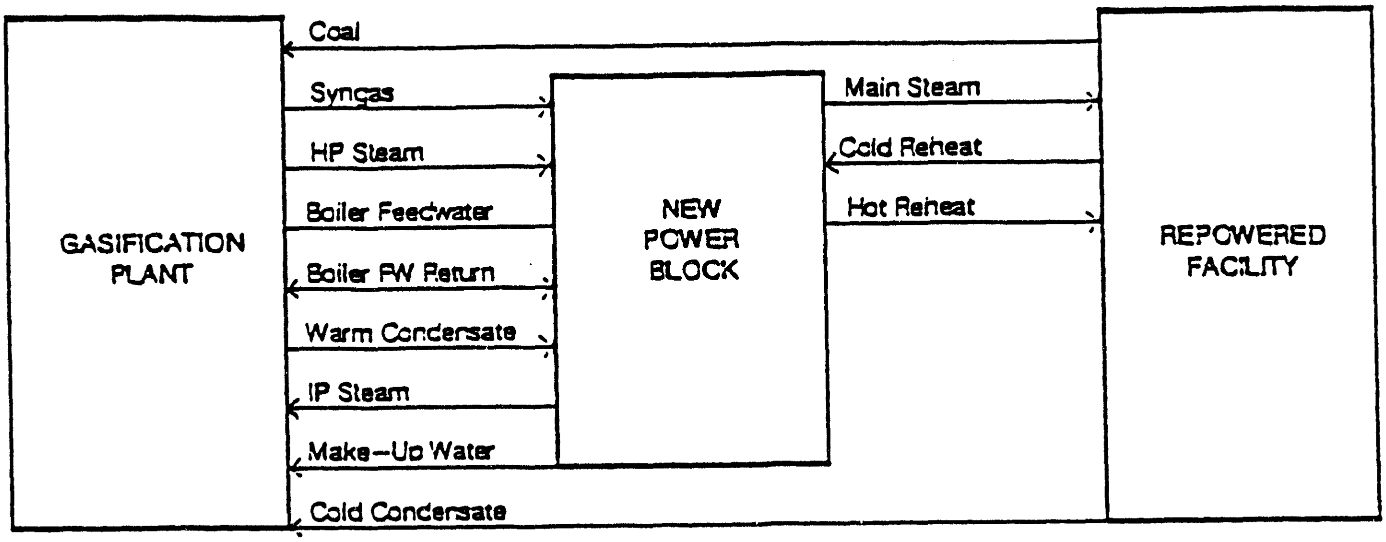


Figure 2 - Simplified Thermal Integration Diagram

The combustion turbine generator will produce approximately 192 MW. Steam generated by the combustion turbine heat recovery steam generator in the gasification island will supply the existing steam turbine generator to produce an additional 105 MW. Plant auxiliaries in the power generation and coal gasification areas and the oxygen plant will consume approximately 35 MW, for a net electrical production of approximately 262 MW.

The new power generation facility will include additional water treatment systems. The combustion turbine has steam injection for NOx control. The amount of this injection flow is reduced compared to conventional systems because the syngas burned in the combustion turbine is moisturized at the gasification facility, making use of low level heat in the process. This flow is continuously made up at the power block by clarification and treatment of river water.

The air separation unit (ASU), which provides oxygen and nitrogen for use in the gasification process, is not an integral part of the plant thermal balance. The ASU will utilize services such as cooling water and steam from the gasification facilities, and will be operated from the gasification plant control room.

OPERATIONS

Destec and PSI will independently operate their respective gasification and power generation facilities. Operating interface parameters and other key data will be interchanged continuously between the gasification and power generation control rooms. In normal operation, syngas production will follow combustion turbine fuel demand. Thermal balance between the facilities is flexible to a certain extent, utilizing the heat recovery steam generator and gasification facility heat exchangers, and will follow the syngas production.

Operation of the facilities will be closely coordinated during startup and shutdown. The combustion turbine operates on auxiliary fuel (oil) at low loads during startup and shutdown. A "flying switch" will be made to syngas and the combustion turbine will ramp up to full load at its normal rates.

The CGCC plant will have two commercial byproducts during operation. Elemental sulfur removed via the gas clean-up systems will be marketed to fertilizer plants and other sulfur users. slag, the sand-like material from the gasifier will be available for use as a construction material.

COST AND EFFICIENCY

Integration of the new and existing power generation facilities and the new gasification facilities have resulted in lower installed cost and better efficiency than other "environmentally equivalent" coal based power generating projects. Reduced development effort and shorter schedule can also result from choosing to repower existing stations, because of the siting problems that even clean coal technologies may have for greenfield installations.

The net plant heat rate for the entire new and repowered unit is forecast to be approximately 9025 Btu/kWh, representing an approximate 20 percent improvement over the existing unit. Certain major component manufacturer margins and guarantees (combustion turbine, HRSG, HTHRU, etc.) are included in this energy balance calculation; actual operation is expected to be slightly better. This heat rate will be among the lowest of commercially operated coal-fired facilities in the United States.

The total estimated installed cost for the Project is $362 million, of which Destec's and PSI's facilities are $240 million and $122 million, respectively. These estimated figures include escalation through 1995, environmental and permitting costs, and startup costs. On this basis, the total estimated installed cost of the project is approximately $1380 per kW of net generation. The U.S. Department of Energy's Clean Coal Technology Program (Round IV) provides partial funding for the project. PSI and Destec will provide the balance of the funds for their respective portion of the job. The DOE funding reduces the estimated installed cost to approximately $820 per kW of net generation.

ENVIRONMENTAL BENEFIT

The plant will be designed to substantially outperform the standards established in the CAAA for the year 2000. The Destec technology to be employed will remove at least 98 percent of the sulfur in the coal. SO_2 emissions will be less than 0.20 pounds per million Btu's of fuel. NO_x emissions from both the gasification block and the power block are expected to be less than 0.7 lb/MWh. CO_2 emissions will also be reduced, approximately 21 percent on a per kilowatt-hour basis by virtue of the increased system efficiency. Figure 3 compares emissions of current Wabash Unit 1 with expected emissions from the Project.

PROJECT ENVIRONMENTAL DATA

A. EXPECTED PROJECT EMISSIONS

CGCC EMISSIONS	SO_2	NO_x	CO	PM	PM-10	VOC
Gasification Block Tons/Yr.	23	18	124	25	20	12
Power Block Tons/Yr.	204	774	374	46	42	13
Total CGCC Tons/Yr. (note 1)	227	792	498	71	62	25

B. COMPARISON TO EXISTING UNIT

EMISSIONS, LBS/MWH	SO_2	NO_x	CO	PM	PM-10	VOC
Unit 1 Boiler	38.2	9.3	0.64	0.85	0.85	0.03
CGCC	0.21	0.75	0.47	0.07	0.06	0.02
EMISSIONS, LBS/MMBtu						
Unit 1 Boiler	3.1	0.8	0.05	0.07	0.07	0.003
CGCC	0.02	0.08	0.05	0.01	0.01	0.003

Note: 1) Based on 2,111,160 MW/hr estimated annual generation (268 MW at 90% capacity factor)

Figure 3 - Environmental Emissions

By providing an efficient, reliable and environmentally superior alternative to utilities for achieving compliance with the CAAA requirements, the Wabash Project will represent a significant demonstration of Clean Coal Technology.

CURRENT PROGRESS

The Wabash Project was selected by the DOE as part of the Clean Coal Technology Program's Round IV in September 1991. In May 1993, the Department of Energy completed an Environmental Assessment of the Project and issued a Finding-of-No-Significant-Impact. Also, in May 1993, the Indiana Utility Regulatory Commission completed its certification of the project, and the Indiana Department of Environmental Management issued air permits to the project participants. Completion of these major regulatory milestones to support the project construction goals was a result of strong local support, the cooperative spirit of the involved agencies and the strong benefits of CGCC technology.

Engineering for the Project began late in 1991. Process engineering was completed in the first quarter of 1993. Both Destec and PSI are now more than 60 percent complete on overall engineering for their respective portions of the work. Procurement is nearly complete for the engineered equipment. Major equipment and long lead items, such as the gas turbine generator, main air and oxygen compressors, heat recovery steam generator and all major vessels are in fabrication.

Field construction of the project facilities began in the third quarter of 1993, less than two years after selection and approximately one year after completion of the Cooperative Agreement. Construction duration will be less than two years. This period includes two months of commissioning and one month of testing prior to full load operation.

TAMPA ELECTRIC COMPANY INTEGRATED GASIFICATION COMBINED CYCLE SYSTEM

September 9, 1993

DOE - Clean Coal Program

D. E. Pless

TECO Power Services

702 North Franklin Street

Tampa, FL 33602

INTRODUCTION

Tampa Electric Company (TEC) is starting detailed engineering for its new Polk Power Station Unit #1. This will be the first unit at a new site in Polk County, Florida, just east of Tampa. We will use Integrated Gasification Combined Cycle (IGCC) Technology. The unit will utilize oxygen-blown entrained-flow coal gasification, along with combined cycle technology, to provide nominal 250MW (net) generation.

The project is partially funded by the U.S. Department of Energy (DOE) under Round III of its Clean Coal Technology Program. Use of a new hot gas clean-up system will highlight this demonstration of IGCC technology on a commercial scale.

OBJECTIVE

Obviously, the main objective of any power plant is to provide electric power for the utility's Customers. This unit is an integral part of Tampa Electric Company's generation expansion plan. That plan requires baseload capacity to be in service in the summer of 1996. TEC's objective is to build a coal-based generating unit providing reliable, low cost electric power, using IGCC technology to meet those requirements.

Demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such a plant can achieve significant reductions of SO_2 and NO_x emissions when compared to existing and future, conventional coal-fired power plants. In addition, this project is expected to demonstrate the technical feasibility of a commercial scale IGCC unit using hot gas clean-up technology.

COST

The current expected cost for this unit is about 500 million dollars, plus or minus a few million. Being a demonstration project, we are finding every day that we haven't yet fully defined all of the technical requirements for the project. As we develop these aspects, we find that each one has an associated cost impact; some positive, some negative. Even the major suppliers such as General Electric and Texaco are still finalizing designs related to this project. Although the GE

7F is a commercial product, General Electric is still polishing integration concepts for the low BTU/IGCC system. The same holds true for Texaco. Their gasification system is well proven, but as they have worked to integrate it into a cost effective IGCC system, they too are learning more and more about how their own system impacts the other parts of the project.

Back to the 500 million dollars, plus or minus. If you divide that figure by 250MW, it results in about $2,000/KW. When you apply the DOE funding, this number drops to about $1600/KW; still not as low as we would like it to be, but for a first of its kind commercial installation, it is not too bad. What utilities look for are cost effective, reliable ways to install new operating power plants. However, many times, capital costs are not the total deciding factor on what technology to use.

In this day and age, coal is increasingly more difficult to permit. Tampa Electric Company's system needs baseload generating capacity. The operating costs for oil and/or natural gas are higher than coal, especially when you look at the recent past and the potential volatility of these fuel prices. In addition, the IGCC concept offers emissions which approach those of the natural gas-fired combustion turbines. That's why we believe, when all factors are considered, IGCC represents Tampa Electric Company's best option for this new capacity requirement.

The primary IGCC competition in the short term U.S. market is natural gas fired combined cycle. For the IGCC to compete, natural gas prices must rise relative to coal prices, and/or IGCC capital costs must decrease. Natural gas prices have in fact increased over the last year. Whether these trends continue, and how they continue is anybody's guess.

Natural gas prices are not in the technology suppliers control but are still very important. Capital cost <u>is</u> in the control of the technology suppliers. Reduction in capital costs of IGCC technology is required to ensure its long term competitiveness. Capital cost reduction probably represents the most significant challenge for IGCC technology suppliers. Through economies of scale or other means, such as reduced design margins, repetitive designs and improved fabrication techniques, IGCC capital cost must be reduced for the IGCC technology to be consistently competitive in the future.

Tampa Electric Company's economic justification for this project has been, in large part, due to the $120 million funding from the DOE. The Clean Coal Technology Program provides a bridge between the economics of today and those of the future. Tampa Electric is proud to be taking a leadership position applying these funds to further IGCC technology for future use by other utilities in the U.S. and the world.

SCHEDULE

The total project, IGCC Combined Cycle, is expected to be put into service July 1996. Originally, we had considered using the 7F machine in simple cycle to meet Tampa Electric Company's peaking capacity requirements for the summer of 1995 and the fall of 1996. As you are aware, Tampa has an extreme air conditioning load requirement during the summer and, as many of you may not know, TEC has a similar peak in the winter time when the cold north winds bring the temperatures crashing down to the 30°F range. Native Floridians can not tolerate this extremely cold temperature and some begin using their electric heating elements when the temperature drops below 40°F. This causes peaks as high as or higher than the summer peaks, but usually for a much shorter duration. As Tampa Electric Company has continued to look at their generation needs, this peaking requirement during the summer of 1995, and the following winter, has shown a recent shift allowing us to move the installation of the 7F CT to coincide the overall IGCC requirements for total system operation in July of 1996. This will allow us to perform a more efficient and effective site development and overall project installation thereby saving capital dollars.

The current schedule requires permits be received in the early part of 1994, with construction following immediately thereafter, because site will require a massive amount of development work requiring considerable time to convert the existing mine cuts into a usable cooling water canal. The two main pieces of equipment impacting our schedule are the 7F Combustion Turbine scheduled to be delivered in the middle of 1994 and the Radiant Syngas Cooler scheduled to be delivered in May 1995.

PARTICIPANTS

U.S. Department of Energy

The Department of Energy has entered into a Cooperative Agreement, for demonstrating IGCC technology with HGCU, with TEC under Round III of the Clean Coal Technology (CCT) Program. Project Management is based in DOE's Morgantown Energy Technology Center in West Virginia.

Tampa Electric Company

Tampa Electric is responsible overall for the implementation of this project. TEC is the "Participant" and has repayment responsibilities to DOE.

Tampa Electric Company (TEC) is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and utilization. TEC has about 3200MW of generating capacity, of which 97% is coal-fired. TEC services approximately 470,000 customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TEC owns five generating stations; two are coal-fired (2850 MW), two are heavy oil-fired (250MW), and one is natural gas-fired (11MW). TEC also has four combustion turbines with about 160MW of generating capacity, used for start-up and peaking.

TECO Power Services

TECO Power Services (TPS) is also a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-utility generation market. TPS has recently started up a 295MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and Tampa Electric Company are purchasing the output of this plant under a twenty-year power sales agreement.

TPS is responsible to Tampa Electric for the overall project management for the DOE portion of this IGCC project. TPS will also concentrate on commercialization of this IGCC technology, as part of the Cooperative Agreement with the U.S. Department of Energy.

Other participants are GE, General Electric Environmental Services, Texaco, Air Products, Raytheon Engineers & Constructors, and Bechtel, which acts as our engineer and construction manager, we consider these other participants to be our partners in implementing this important project.

THE SITE

The Polk Power Station will be built on an inland site in southwestern Polk County, Florida. The site, about 11 miles south of Mulberry, is a tract previously and currently mined for phosphate and is basically unreclaimed. This site was intended to be used for TEC's next generation addition, originally a 75MW combustion turbine (CT) scheduled to be in service in mid-1995. The site was selected by an independent Community Siting Task Force, commissioned by TEC to locate a site for its future generating units.

The seventeen person group consisted of environmentalists, educators, economists, and community leaders. The study, which began in 1989, considered thirty-five sites in six counties. The Task Force recommended three tracts in southwestern Polk County that had been previously mined for phosphate. These sites had the best overall environmental and economic ratings.

The selected site is about 4300 acres. About one-third of it will be used for the generating facilities. As part of this overall plan, the existing mine cuts will be modified and used to form an 850 acre cooling reservoir.

Another one-third of the site will be used for creating a complete ecosystem. It will include uplands, wetlands, and a wildlife corridor. This will provide a protected area for native plants and animals. The final one-third of the site will be unused, and will be maintained for site access and providing a visual buffer.

THE PROJECT

Overview

The Polk Power Station Unit #1 IGCC Project will contain two major pieces which will in combination produce 250MW of total IGCC capacity in mid-1996. The first piece will be the advanced CT. The second piece will be the gasification and combined cycle facilities.

Part of this DOE CCT project will be to test and demonstrate a new hot gas clean-up (HGCU) technology. With the exception of the HGCU, only commercially available equipment will be used for this project. The approach supported by DOE is the highly integrated arrangement of these commercially available pieces of hardware or systems, in a new arrangement which is intended to optimize cycle performance, cost, and marketability at a commercially acceptable size of nominally 250MW (net). Use of the HGCU will provide additional system efficiencies by demonstrating the cycle improvements realized from cleaning syngas at a temperature of about 1000°F rather than utilizing more traditional Cold Gas Clean-up (CGCU) methods: cooling the gas to about 100°F before the sulfur removal is attempted. This low temperature process has the disadvantage of the irreversible cooling losses and associated reheating before admitting the syngas to the CT.

Gasification

This unit will utilize commercially available gasification technology as provided by Texaco in their licensed oxygen-blown entrained-flow gasifier. In this arrangement, coal is ground to specification and slurried in water to the desired concentration in rod mills. The unit will be designed to utilize about 2000 tons per day of coal (dry basis). This coal slurry and an oxidant (95% pure oxygen) are then mixed in the gasifier burner. This produces syngas with a heat content of about 250 BTU/SCF (LHV). The oxygen will be supplied from an Air Separation Unit (ASU). The gasifier is expected to achieve greater than 95% carbon conversion in a single pass. It is currently planned for the gasifier to be a single vessel feeding into one radiant syngas cooler where the gas temperature will be reduced. After the radiant cooler, the gas will then be split into two (2) parallel convective coolers, where the temperature will be cooled further to about 900°F. One stream will go to the 50% capacity HGCU system and the other stream to the traditional CGCU system with 100% capacity. This flow arrangement was selected to provide assurance to TEC that the IGCC capacity would not be restricted due to the demonstration of the HGCU system.

The CGCU system will be a traditional amine scrubber type. Sulfur removed in the HGCU and CGCU systems will be recovered in the form of sulfuric acid. This product has a ready market in the phosphate industry in the central Florida area. It is expected that the annual production of about 37,000 tons of sulfuric acid from by this nominal 250MW (net) IGCC unit will have minimal impact on the price and availability of sulfuric acid in the phosphate industry.

Most of the ungasified coal exits the bottom of the gasifier/radiant syngas cooler into the slag lockhopper where it is mixed with water. These solids generally consist of slag and uncombusted coal products. As they exit the slag lockhopper, these non-leachable products are readily saleable for blasting grit, roofing tiles, and construction building products. TEC has been marketing slag from its existing units for such uses for over 25 years.

Obviously, the water in the slag lockhoppers requires treatment before it can be either discharged or reused. All of the water from the gasification process will be cleaned and reused, thereby creating no requirement for discharging process water from the gasification system.

Air Separation Unit

The Air Separation Unit (ASU) will use ambient air to produce oxygen for use in the gasification system and nitrogen which will be sent to the advanced CT. The addition of nitrogen in the CT combustion chamber has dual benefits. First, since syngas has a substantially lower heating value than natural gas, a higher mass flow is needed to maintain total turbine input. Second, the nitrogen acts to control potential NO_x emissions by reducing the combustor flame temperature.

The ASU will be sized to produce about 2100 tons per day of 95% pure oxygen and about 6300 tons per day of nitrogen. The ASU is being designed and constructed as a turnkey project.

HGCU

The HGCU system is being developed by General Electric Environmental Services, Inc. (GEESI). This process is undergoing pilot plant testing at GE's laboratory facilities in Schenectady, NY. The advantage of the HGCU over the CGCU is the ability to use a hotter syngas in the combustion turbine. Instead of having to cool the gas prior to sulfur removal, the HGCU will accept gas at 900-1000°F. The successful demonstration of this technology will provide for higher efficiency IGCC systems.

One specific issue in the HGCU system for our project is the metal oxide sorbent being demonstrated. The sorbent material used will be zinc titanate. This is a more robust material and more amenable to the oxygen-blown entrained-gasifier syngas than zinc ferrite, which is usually considered for air-blown gasifiers.

A regeneration system will produce a concentrated (about 13%) SO_2 stream. This will feed a sulfuric acid plant for production of a saleable acid by-product.

The feasibility of two (2) other support processes will be investigated for potential improvements to this process. In addition to the high efficiency primary cyclone being provided upstream of the HGCU system, a high temperature barrier filter will be considered for possible installation downstream of the HGCU to protect the combustion turbine. Use of sodium bicarbonate, $NaHCO_3$, will also be investigated for possible injection upstream of the primary cyclone for removal of chloride and fluoride species.

Combined Cycle

The key components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and generators.

GE is currently optimizing arrangements for increasing fuel inlet temperature and also for lowering the pressure drop across the fuel inlet control valving. This has a compounding positive effect on cycle efficiency by also allowing a lower pressure in the ASU, requiring less air and nitrogen compressor parasitic power.

The HRSG is installed in the combustion turbine exhaust to complete the traditional combined cycle arrangement and provides steam to the steam turbine with a capacity of about 120MW.

No auxiliary firing is proposed within the HRSG. The HRSG will be used to recover the CT exhaust heat energy and high pressure steam production from the coal gasification (CG) plant. All high pressure steam will be superheated in the HRSG before delivery to the high pressure ST.

The ST will be designed as a double flow reheat turbine with low pressure crossover extraction. The ST generator will be designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1,400 psig and 990°F with 1,000°F reheat inlet temperature.

Integration

The heart of the overall project will be the integration of the various pieces of hardware and systems. Maximum usage of heat and process flow streams can usually increase overall cycle effectiveness and efficiency. In our arrangement, benefits are derived from using the experience of other projects, such as Cool Water, to optimize the flows from different subsystems. For example, low pressure steam from the HRSG will be produced to supply heat to the CG facilities for process use. The HRSG will also receive steam energy from the CG syngas coolers to supplement the steam cycle power output. Low pressure steam will also be provided by the HRSG for condensate heating.

Probably the most novel integration concept in this project, is our intended use of the ASU. This system provides oxygen to the gasifier in the traditional arrangement, while simultaneously using what is normally excess or wasted nitrogen, to increase power output and improve cycle efficiency and also lower NO_x formation.

Emissions

The primary source of emissions from the IGCC unit is combustion of syngas in the advanced CT (GE 7F). The exhaust gas from the CT will be discharged to the atmosphere via the HRSG stack. Emissions from the HRSG stack are primarily NO_x and SO_2 with lesser quantities of CO, VOC, particulate matter (PM). SO_2 and NO_x emissions are expected to be about 0.2lb/mmBtu and 0.1 lb/mmBtu, respectively, for the 100% CGCU mode. The emission control capabilities of the HGCU system are yet to be fully demonstrated. Therefore, some emission estimates are higher compared to estimated emissions from the CGCU system. After the completion of the 2-year demonstration period, the lower emission rates from the CGCU system must be achieved to meet permit requirements. It is expected that at least 96 percent of the sulfur present in the coal will be removed by the CGCU and HGCU systems.

The advanced CT in the IGCC unit will use nitrogen addition to control NO_x emissions during syngas firing. Nitrogen acts as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection NO_x control methods. Maximum nitrogen diluent will be injected to minimize NO_x exhaust concentrations consistent with safe and stable operation of the CT. Water injection will be employed to control NO_x emissions whenever backup distillate fuel oil is used.

Demonstration

Part of the Cooperative Agreement for this project is the two-year demonstration phase. During this period, it is planned that about four to six different types of coals will be tested in the operating IGCC power plant. These coals will be classic eastern coals; Eastern being defined as east of the Mississippi. We would expect to test burn such coals as Illinois 6, Kentucky 9, Eklhorn 3, etc. The results of these tests will provide data for utilities in many coal producing areas to be able to determine operating characteristics and economics related to using IGCC in their areas with local coals. The results of these tests will compare this unit's efficiency, operability, and costs, and report on each of these specific test coals against the design basis coal.

These results should provide a menu of operating parameters and costs which can be used by utilities in the future as they make their selection on methods for satisfying their generation needs, in compliance with environmental regulations.

COMMERCIALIZATION

We have found this technology is vastly different from what utilities are accustomed to using. The non-technical or business issues such as project management, and contract administration also have significantly different requirements. The business issues must be successfully addressed by both the utilities and the different technology suppliers, in order for IGCC power plants to achieve ultimate commercial success. In our project, this has been a major task: meshing cultures from the utility, refinery, industrial and sulfuric acid industries. Although it has been very different for us, we have successfully achieved a team concept that will be the template for IGCC Units built in the future.

Major contributions to IGCC efficiency improvements have been made in the combustion turbine/combined cycle portions of the plant. What needs to happen now are continued significant improvements in the gasification and integration side. Not only in operating efficiency but also cost effectiveness and environmental controls.

This has been the case with all fuel burning technologies in the past. The actual combustion of a fuel produces the side effects that many consumers are concerned about. The entire gasification industry needs to continue to develop methods for processing coal into fuelgas in a manner that minimizes emissions of environmentally sensitive constituents. We feel there should be intensified technology vendor effort in the general gasification area to develop and implement these needed improvements, in order to support long term commercial viability of IGCC.

One of the major hurdles we have had in this project, is adapting to the contracting requirements for these new and different technologies. The first item we encountered was the requirement to buy a license. This is a copncept totally new for most utilities. In addition to the gasification technology license which we expected, we also found requirements for licenses which are typical in businesses for acid gas removal, sulfur recovery, and sulfuric acid production. The license provides information necessary to implement this technology, but usually not the equipment necessary to do it. When a utility buys a boiler, the supplier provides the required hardware as well as the technology, in the overall pricing as a total package.

The technology that is licensed is "know-how" and generally not formally written down. It is therefore very difficult to monitor and/or control. Most technology licensors have resisted defining what it is they are concerned about protecting. Therefore it is difficult for us to draft language in a confidentiality agreement to protect something which is not specifically detailed. Most vendors would like to license their technology by describing what is not covered rather than what is. That way their technology definition is more broad.

In addition to technologies, guarantees are also significant differences with which utilities are not accustomed to dealing. The license of a technology generally applies only to the process performance and not necessarily the overall end product. Licensors look towards equipment vendors to provide the equipment guarantees. This leads to split responsibilities and difficult, contracting. If this system doesn't work, then it's up to the utility to determine who is at fault and try to negotiate resolution of the problem. Because the technology supplier is not providing equipment, his level of liquidated damage support is considerably less than is usually available to utilities. A license is a small part of the overall project and the damages associated with that are very small and insufficient to protect the utility in case the equipment or technology doesn't work as intended by the licensor. Technology suppliers usually only provide process knowledge and, in some cases, equipment recommendations. They leave it up to the purchaser to determine how to implement the technology and engineer, develop, and buy the equipment and hardware necessary to get benefit from the license.

Another area we are finding extremely difficult is confidentiality. The licensors' primary business is that of supplying technology. They need the license to protect their livelihood. They generally have no desire to supply hardware, and only get involved in certain instances where they can become an owner of the plant. For electric utilities, this is not often possible.

Therefore, when the licensor supplies his technology a secrecy agreement is normally required. This significantly compounds the "normal" way of conducting of business for a utility.

Administration of these agreements demands continuous management attention. Even simple things, like buying minor components, usually results in significant requirements for subsupplier secrecy agreements and negotiations of these agreements with the technology vendors. It is our experience and opinion that the technology vendors are very difficult to negotiate with due to their requirements for secrecy.

These confidentiality agreements extend down not only to the A/E and to the suppliers, but also subsuppliers. This could have a potential for utilities not wanting to fight the battle to implement a new technology. It would be a shame if the industry rejected gasification due to the new and difficult requirements of confidentiality for something which may not be readily and totally disclosed to the utility. It also increases the overall costs and duration of the project due to the fact that attorneys now have to get involved in negotiating for simple purchases. This has the potential for impacting project costs in the range of, pick a number, 5%, 10%, 15%, or 20%. For the technology to be successful, the technology licensors and the utilities will have to be flexible and reach a common understanding in the very near future.

Other opportunities that are seen, are for turnkey parts of the IGCC project. We are proceeding in our project to buy the air separation unit on a turnkey basis. That means they will engineer, procure, install, and start-up the air plant. There was even a proposal for them to operate the air plant and sell us air "over the fence". This alternative will continue to be evaluated by utilities as they look for ways to reduce the overall capital costs and make the IGCC system more competitive in the open market.

It is suggested that technology vendors could ease the overall burden and costs if they were to approach this technology similar to the way the boiler manufacturers used to do with the utility industry. Utilities would go to one person to buy the technology, equipment, and the guarantees. This certainly eased the burden for the utilities, but admittedly put more risk on the licensors or vendors. If technology suppliers wish to participate in the utility market, they should seriously consider this, or some alternative option, attractive to utilities.

The bottom line is that both utility and technology suppliers must maintain flexibility and open mindedness in their approach to this new business. Both sides will have to change their way of normally doing business in order for the IGCC concept to proceed successfully. We have developed ways to bridge this gap for our project but it has been very difficult and slow in coming. Technology suppliers have been very reluctant to change their way of doing business. Most of them have been doing business this way for the past forty or fifty years and change is very difficult for them. To reap the rewards for the massive utility industry market that is out there, they must be willing to make this compromise.

Tampa Electric had to learn this flexibility. We have seen that there are many different ways to conceive, design, install, and operate a plant. One of these is to physically relocate our production engineering team to our A/E's offices to expedite the overall design and review process. It normally took several weeks to process a single drawing where the vendor would prepare the drawing, send it to the A/E, the A/E would review it in his offices and send it back. It would be sent to the client for final approval. For our project, we have relocated our personnel to the A/E offices to simultaneously review and approve concepts, specifications, and drawings as they are being prepared rather than sequentially. We expect this to pay significant monetary and schedule gains. We understand this may be standard for refinery and other types of projects, but it was a major philosophy change for us.

The achieve wide success for utilities, suppliers, and A/E's we must all accept the challenge in recognizing that flexibility and ingenuity applied to both technical and business issues will be the key to successful commercialization of any new concept, specifically coal gasification IGCC. We feel that we now have a achieved this success with our partners on our project and invite you to pursue our and other similar and novel approaches to realize the tremendous benefits associated with IGCC Technology.

CLEAN COAL POWER
at
TOMS CREEK

Michael R. Schmid
TAMCO POWER PARTNERS
2600 Reach Road
Williamsport, PA 17701-0308
(717) 326-3361

Paper presented at Second Annual Clean Coal Technology Conference
Atlanta, September 7-9, 1993

CLEAN COAL AT TOMS CREEK

INTRODUCTION

On October 20, 1992 the US Department of Energy (DOE), through the Morgantown Ener Technology Center, entered into Cooperative Agreement DE-FC-21-93MC92444 with Power Partners to implement the Toms Creek Integrated Gasification Comb ycle Demonstration Project.

The process design is proceeding as scheduled, and a draft Environmental Information Volume has been produced. The overall project schedule, however, may have to be adjusted when the Power Sales Agreement has been finalized.

TECHNOLOGY OVERVIEW

Coal gas is produced in an air-blown fluidized bed gasifier using U-GAS® technology. Most of the sulfur is captured by dolomite which is fed to the gasifier for that purpose. The balance of the sulfur and the particulate matter entrained by the coal gas are controlled by the hot gas clean-up system which is located between the gasifier and the gas turbine generator. Electrical power is generated from the combustion of the clean hot coal gas in a gas turbine generator. Power also is generated from the steam produced in a heat recovery steam generator by cooling the hot combustion gases coming from the gas turbine generator.

When coal gas is unavailable, power generation will be maintained by firing the gas turbine generator with natural gas.

The contaminants in the exhaust gases leaving the heat recovery steam generator are less than the maximum allowed by applicable standards. The ash and spent dolomite discharged from the gasifier have been shown to be environmentally benign. Essentially there is no water discharge from the plant.

PROJECT OVERVIEW

Project Goals

The primary objective of the Project is to demonstrate an Integrated Coal Gasification Combined Cycle (IGCC) system in a fully commercial setting. The IGCC Technology achieves significant reductions in emissions compared to existing coal-fired facilities. This technology will provide future energy needs in a more efficient and environmentally acceptable manner.

TAMCO will demonstrate the pressurized, air-blown, fluidized bed, integrated coal gasification combined cycle technology. The demonstration includes all major sub-systems: coal feeding; a pressurized, air-blown, fluidized bed gasifier capable of utilizing high sulfur bituminous coal; a gas conditioning system for removing sulfur compounds and particulates from the coal gas at elevated temperatures; an advanced combustion turbine able to utilize low Btu coal gas as fuel; the steam cycle, including a heat recovery steam generator and steam turbine generator; all control systems; and the balance of the plant.

Project Participants

TAMCO Power Partners was organized to provide a rational means for two large, diverse companies to demonstrate, with substantial Government support, the commercial viability of a Clean Coal technology. Each partner owns fifty percent of TAMCO. Together the partners will invest slightly more than half (± 51.7%) of the estimated $196.6 million total project cost. The Government will advance 48.3% of the cost, up to a maximum of $95.0 million.

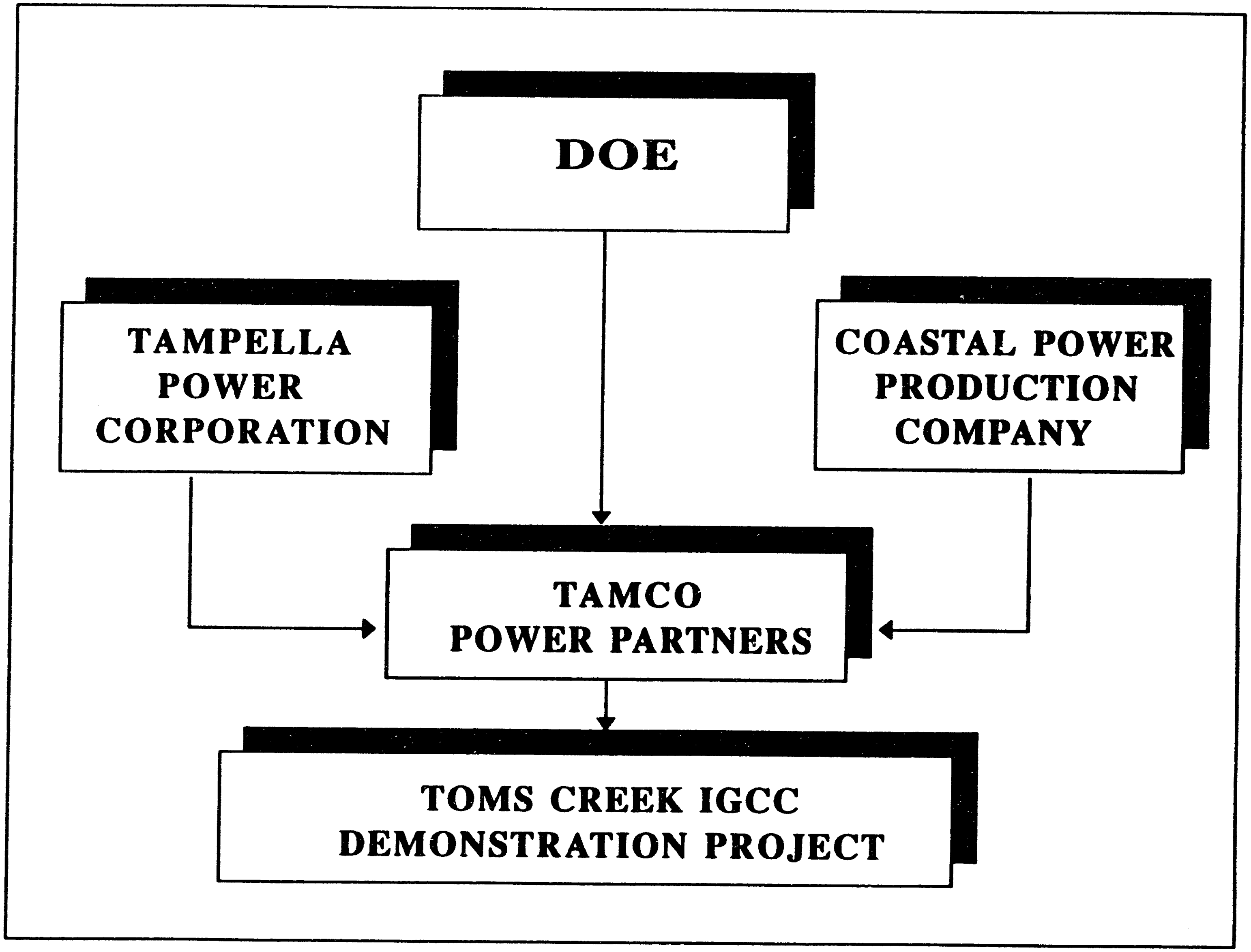


Figure 1. Toms Creek Project Team

TAMCO Power Partners

TAMCO Power Partners is a General Partnership formed under the laws of the State of Delaware by subsidiaries of Tampella Power, Incorporated and The Coastal Corporation. As shown in Figure 1, TAMCO is controlled through Tampella Power Corporation (Williamsport, PA) and Coastal Power Production Company (Roanoke, VA). TAMCO's principal office is co-located with Tampella Power in Williamsport; TAMCO is staffed by Tampella personnel under an Administrative Services Agreement between TAMCO and Tampella.

Coastal Power Production Company

Coastal Power Production Company of Roanoke, VA, is a subsidiary of The Coastal Corporation (NYSE:CGP), a Houston-based energy holding company. Coastal has consolidated assets of more than $9 billion and subsidiary operations in natural gas transmission and storage; oil and gas exploration and production, refining, and marketing; coal, chemicals, trucking, and independent power production. Coastal operates three natural gas fired combined cycle power plants.

Tampella Power Corporation

Tampella Power Corporation of Williamsport, PA, is a subsidiary of Tampella Power Inc., a major international producer of chemical recovery systems for the pulp and paper industry and power generation systems for industry and utilities. The company's principal markets are in North America, Europe, Southeast Asia, and the former Soviet Union.

Project Responsibilities

Coastal Power is responsible for the design, construction, and operation of the Power Island and the balance of the plant. The Power Island includes the gas turbine generator, the heat recovery steam generator, and the steam turbine generator. Coastal subsidiaries will provide the fuel, ash disposal, and the site for the project.

Tampella Power Corporation is providing the design, construction, and, through the test period, the operation of the Gasification Island. The Gasification Island includes the gasifier, the gasifier feed and discharge systems, and the hot gas clean-up systems. Tampella will conduct the tests during the three year demonstration period. TAMCO Power Partners is being provided with office space and staff by Tampella.

TAMCO Power Partners administers the Cooperative Agreement with DOE.

Project Location

The Demonstration Plant will be built at Toms Creek, next to a coal preparation plant owned by VICC, a Coastal subsidiary located near Coeburn, in Wise County, Virginia.

U-GAS® TECHNOLOGY

The U-GAS® process is a pressurized fluidized bed coal gasification process which produces a low to medium Btu fuel gas from a variety of feedstocks including highly caking, high sulfur, and high ash coals. A simplified diagram of the U-GAS® gasifier is shown in Figure 2.

Coal Preparation and Feeding

The incoming coal is sized to minus 1/4 inch, plus zero, and dried to a point where surface moisture does not present a handling problem, typically 5% at Toms Creek. Both the coal and dolomite feed systems contain a set of lock hoppers through which the solids feed streams are pressurized, and from which they are transported pneumatically to the gasifier.

Gasification

Within the fluid bed gasifier coal is pyrolyzed, devolatilized, and gasified in a fluidizing medium of air and steam. The bed temperature ranges between 1,650 and 1840°F. The pressure in the gasifier, typically 230 psig, is determined by the pressure drop through the hot gas clean-up systems and the requirements of the gas turbine generator. The temperature within the bed depends on the type of coal and is controlled to maintain non-slagging conditions for the ash. Coal is gasified rapidly in the gasifier and produces a mixture of carbon monoxide, carbon dioxide, methane, hydrogen, water vapor, and about 50% nitrogen; in addition, small quantities of hydrogen sulfide, ammonia, and other trace impurities are evolved. In the reducing environment of the gasifier nearly all of the sulfur present in the coal is converted to hydrogen sulfide before it reacts with the calcium in the dolomite.

Fluidizing gas is introduced into the reactor through the gas distributor plate and through the ash discharge device. In the U-GAS® process, operating conditions in the oxidizing zone are controlled to achieve a low carbon loss which enables a very high 97% overall carbon conversion. The fines elutriated from the gasifier are separated from the product gas in two stages of external cyclones. The fines from both stages are returned to the fluidized bed. The product gas is virtually free of tars and oils due to the relatively high temperature in the upper stage of the gasifier.

HOT GAS CONTAMINANTS

Sulfur

As shown in Figure 3, desulfurization is accomplished in two stages.

The bulk of sulfur is removed in the fluidized bed gasifier by an equilibrium reaction with the calcium in the dolomite. First, the hydrogen sulfide reacts with calcium carbonate and/or calcium oxide to form calcium sulfide. Then, in the lower portion of the gasifier, the calcium sulfide is oxidized to calcium sulfate. The bottoms product from the gasifier is further stabilized by maintaining the temperature in the lower part of the bed near the fusion temperature of the ash so that controlled particle growth occurs while the particle surfaces acquire a vitreous coating.

The balance of the sulfur is removed from the coal gas in the hot gas clean-up system. A regenerable Zn/Ti-based sorbent is used in the post-gasification sulfur removal process. Tampella Power has developed a two fluidized-bed reactor system. Hot coal gas is contacted with Zn/Ti sorbent in the first reactor, where the sulfur is captured by zinc oxide. Sulfided sorbent is regenerated in the second reactor with air and steam. Steam is added to moderate the temperature of the exothermic reaction. The tail gas is recycled to the gasifier where the sulfur dioxide is captured by the dolomite.

Nitrogen Compounds

The nitrogen in the coal forms molecular nitrogen, ammonia, and hydrogen cyanide during gasification. Some of the ammonia is further decomposed at the high temperatures in the gasifier. To reduce the conversion of ammonia to NO_x in the gas turbine, turbine manufacturers are developing staged combustion processes. Whether a selective catalytic reaction system will be required downstream of the gas turbine to meet NO_x emissions limits has yet to be determined.

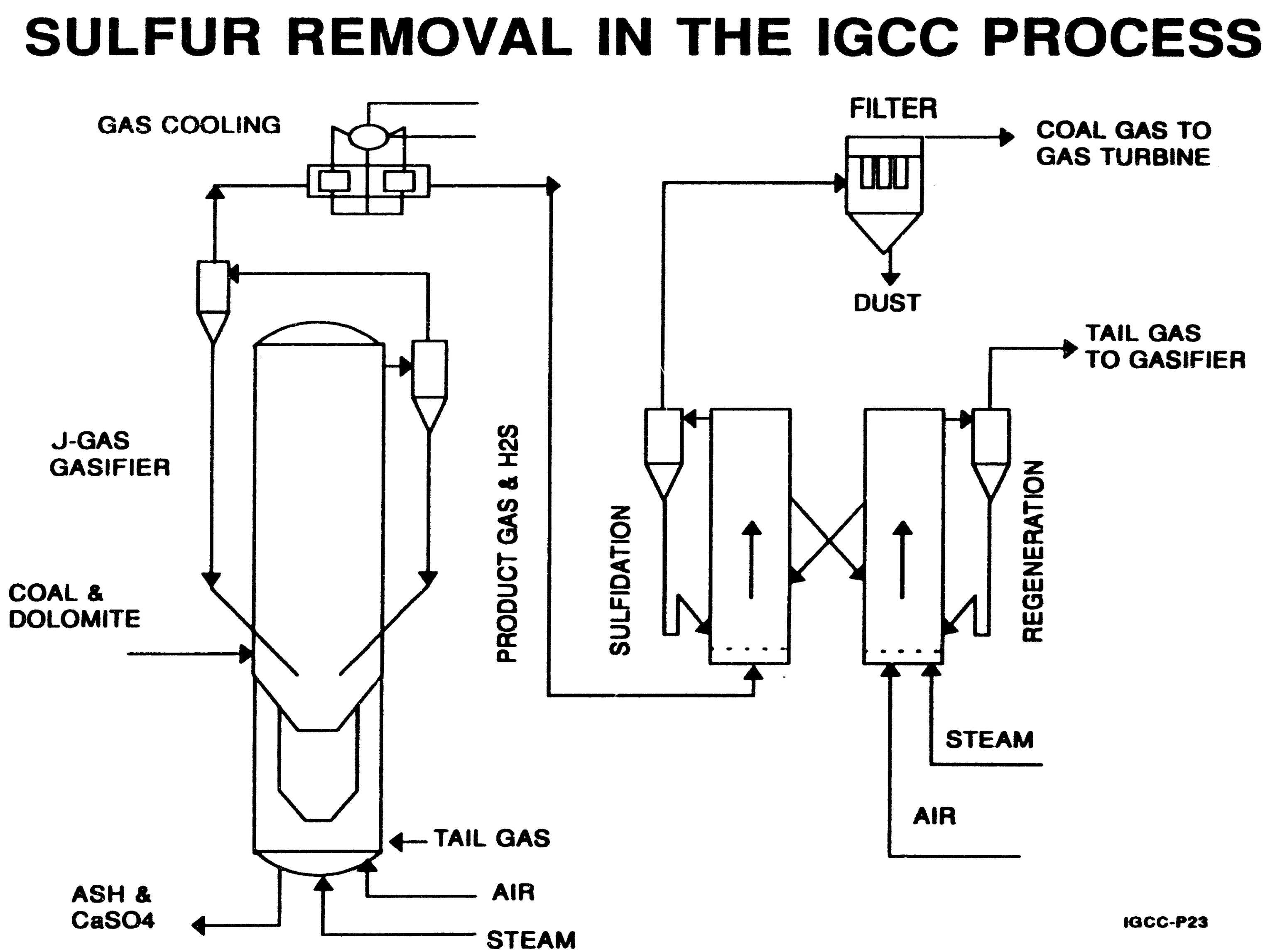


Figure 3. Hot Gas Clean-Up

Alkali Metals

Volatile compounds of sodium and potassium which are formed in the gasifier, can participate in hot corrosion and lead to solids build-up in the gas turbine. In Tampella Power's IGCC process, the product gas is cooled to 1,020°F, which is below the dew point of the alkalai halides. At this temperature the alkali vapors will condense on the particles that are intercepted by the candle filter.

Particulate Removal

To protect the gas turbine generator from particulate damage, and to meet air emissions limits, a candle shaped ceramic barrier filter will be installed upstream of the turbine inlet valves. Most of the solids elutriated from the gasifier are captured by the two series-mounted external cyclones. The candle filter stops the particulate material leaving the external desulfurizer from reaching the gas turbine or the atmosphere. The ultimate disposition of the material trapped by this filter will be determined following its characterization during pilot plant testing, scheduled for next spring.

"Greenhouse" Gases

The "Greenhouse" gases of concern are carbon dioxide, methane, and nitrous oxide. In the IGCC process, the methane which is produced during gasification is burned in the combustor of the gas turbine. Nitrous oxide does not form in the reducing atmosphere of the gasifier, and its formation is not expected at the high temperatures encountered in the gas turbine combustor. The emission of carbon dioxide cannot be avoided. Carbon dioxide emissions are reduced as the efficiency of power generation is improved. One of the features of the IGCC technology is improved fuel efficiency. The Tom's Creek Plant will have an efficiency of only 40%, later plants will reach 47% efficiency; a reduction of some 10-15% in terms of lower carbon dioxide emissions.

THE DEVELOPMENT OF THE TOMS CREEK IGCC PROCESS

Institute Of Gas Technology

The Toms Creek IGCC Demonstration Project utilizes the U-GAS® coal gasification process, a process which was developed by IGT in a multi-phase program which began in 1974. The heart of the U-GAS® process is an air-blown, pressurized, fluidized bed coal gasifier. The development of this process utilized knowledge from earlier low and medium Btu coal-to-fuel-gas projects at IGT that date back to 1950. The U-GAS® process feasibility was demonstrated initially using metallurgical coke and char as feed to a low-pressure pilot plant. Subsequent tests were made with sub-bituminous and bituminous coals. Eventually process feasibility was proven using high-sulfur caking bituminous coals. Necessary environmental data were collected and the reactor dynamic responses were investigated. Process data were developed for the scale-up and design of a commercial plant.

The original pilot plant had an operating pressure of 50 psig. A high-pressure process development unit was built in 1984 and data were obtained for the gasification of sub-bituminous coal and lignite at pressures up to 450 psig. Test runs included the use of steam and air to gasify bituminous coal with in-situ desulfurization. In support of demonstration plant designs, several tests also conducted in the low-pressure pilot plant with different design feedstocks.

The IGT pilot plants have been operated for 12,000 hours on a variety of feeds including highly caking, high ash, and high sulfur coals. The process has demonstrated its capability to gasify and produce ash agglomerates from raw coal. The operation of the pilot plant has established process feasibility; has demonstrated safe, repeatable, and reliable operability; and has provided a valuable data base for the design of larger plants such as the Toms Creek IGCC Demonstration Project. Successful demonstration at Toms Creek will move the U-GAS® process into the commercial marketplace.

Tampella Power Corporation

The Toms Creek IGCC Project utilizes a hot gas clean-up system to remove residual sulfur compounds and particulate matter from the gasifier product gas. An integrated pilot plant was built by Tampella in Finland to study gasification and hot gas clean-up. It is diagrammed in Figure 4. Following more than 1,000 operating hours, the plant is being modified to incorporate the external desulfurization system discussed above. The data generated from this 10 MW (t) pilot plant are being used to confirm the theoretical design of the 140 MW (t) demonstration plant at Toms Creek.

TOMS CREEK PROCESS DESCRIPTION

Site and Coal

The greenfield IGCC Project will be sited adjacent to an existing coal preparation plant at Toms Creek. The existing coal refuse disposal facilities will be utilized for ash disposal. Coal for the project will be supplied by the Coastal subsidiary which owns the reserves and operates the preparation plant. The design coal is a high volatile A bituminous, low sulfur (1-1.5% S) coal with a higher heating value of 13,400 Btu/lb. At least two high sulfur coals will be tested during the demonstration period. One test coal will have a free swelling index greater than five.

Process

A flow diagram of the Toms Creek IGCC Demonstration Plant is shown in Figure 5. Crushed and dried coal, 430 tons per day, and dolomite are fed through lock hopper systems to the pressurized fluidized-bed gasifier.

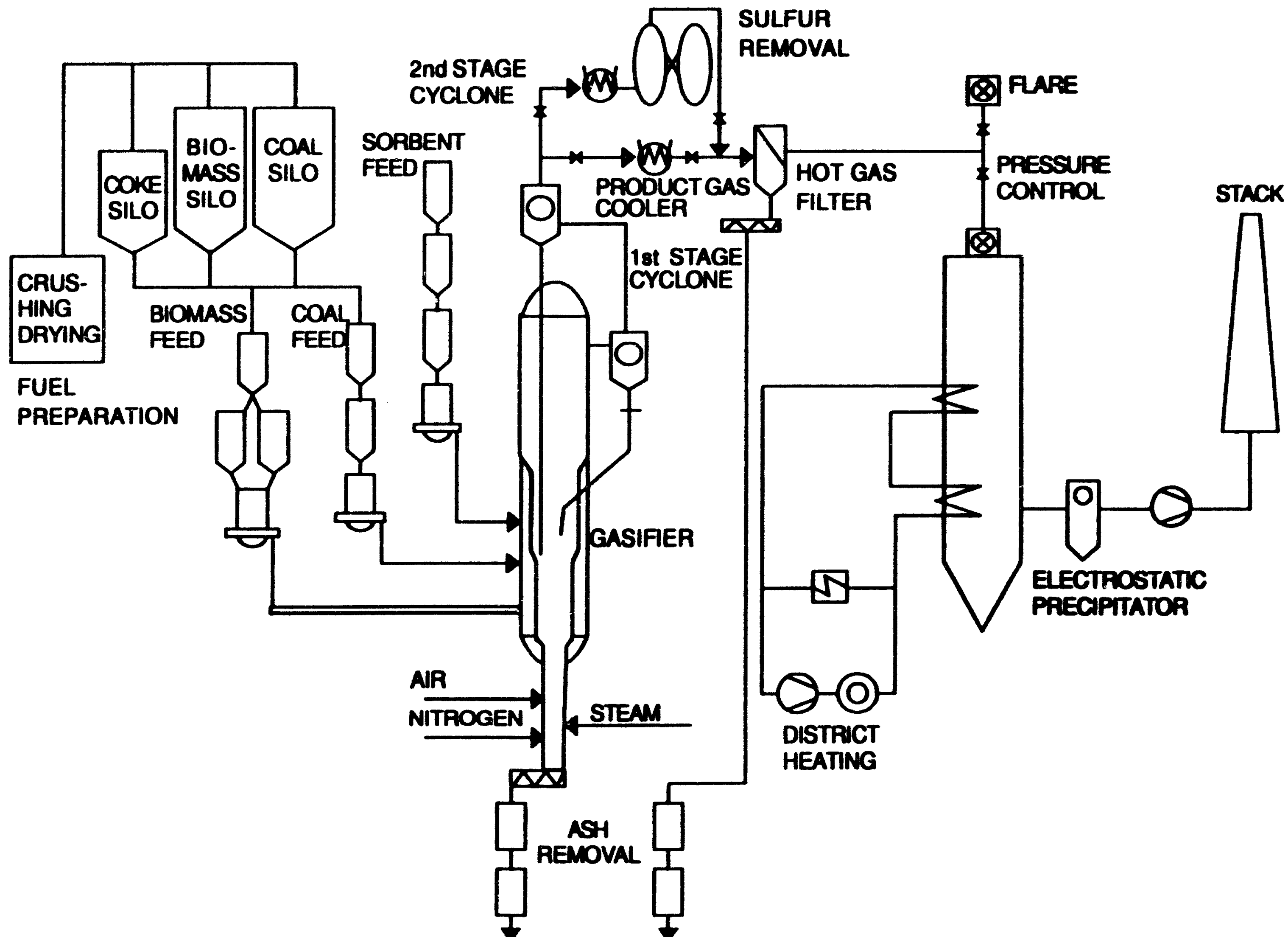


Figure 4. Pilot Plant Schematic Diagram

IGCC-320

U-GAS GASIFIER

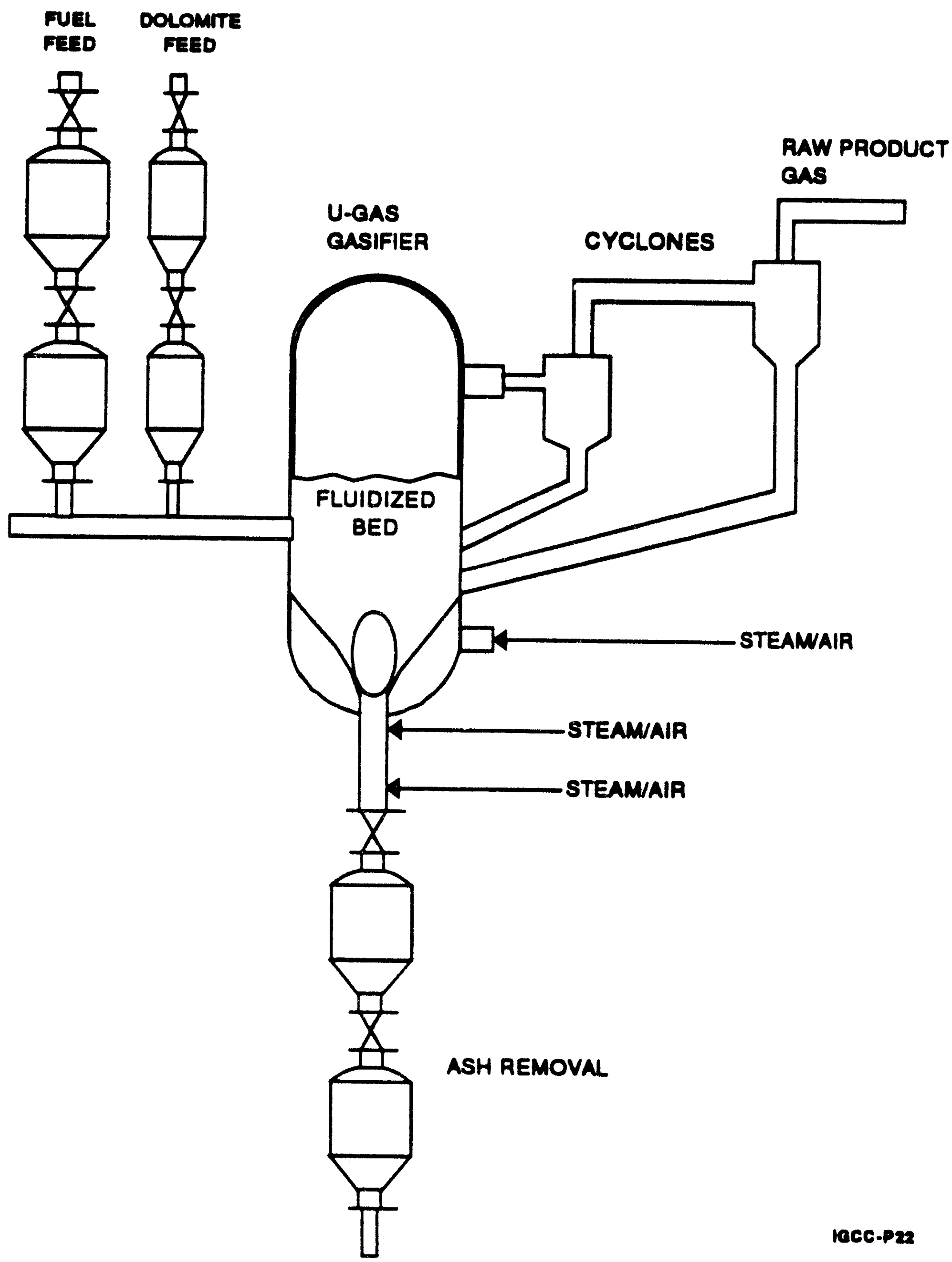


Figure 2. The U-GAS Process Gasifier

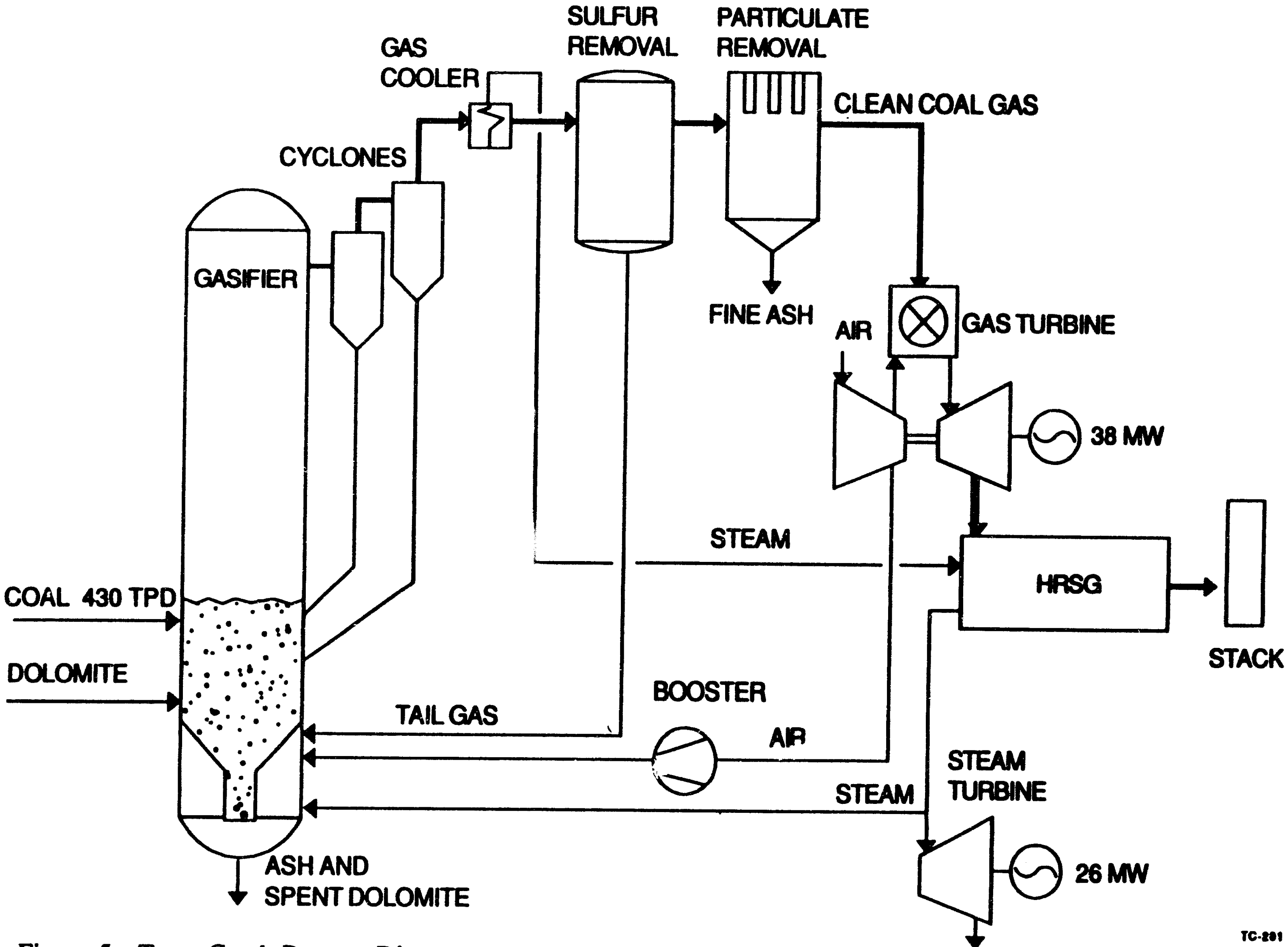


Figure 5. Toms Creek Process Diagram

Gasification air is supplied by the gas turbine air compressor through a booster compressor; gasification steam is extracted from the steam turbine. Two cyclones are used for particle removal. After exiting the cyclones the product gas is cooled to 1020°F in a fire-tube type evaporating gas cooler, the steam side of which is connected to the heat recovery steam generator (HRSG). The external sulfur removal system is located after the gas cooler. The final clean-up step, the ceramic candle unit, filters the product gas to meet gas turbine and environmental particulate requirements. After filtration the product coal gas, at 130 Btu/scf (lhv), is fed to the gas turbine.

The gas turbine air compressor supplies fluidizing air for the gasifier as well as producing combustion air for the turbine. The gas turbine generator is rated at 38 MW.

The waste heat in the turbine exhaust gases is recovered in a heat recovery steam generator. Some of the steam from the HRSG is used in the gasifier; another portion of the steam is used in the regeneration of the hot gas desulfurization sorbent; while the gas cooler supplies saturated steam to the HRSG. Most of the steam from the HRSG, however, is used by the steam turbine generator which generates an additional 26 MW. The net power output from the Toms Creek IGCC would be 60 MW at ISO conditions, or 55 MW at elevation.

Environmental Performance

The Toms Creek plant does not produce any appreciable process waste water streams.

The only solid waste from the plant is a mixture of ash, spent dolomite and calcium sulfate which is discharged from the bottom of the gasifier. Preliminary tests have shown this material to be a non-hazardous waste which could be utilized in road construction or disposed of in a landfill. Initially the glassified product will be placed in the adjacent coal refuse valley, which is part of the coal preparation facility operation.

Air emissions from the plant are anticipated to be well below current requirements: SO_2 emission of 0.056 lb/MMBtu, NO_X emission of 0.24 lb/MMBtu, and particulate PM_{10} emission of 0.016 lb/MMBtu.

Schedule & Status

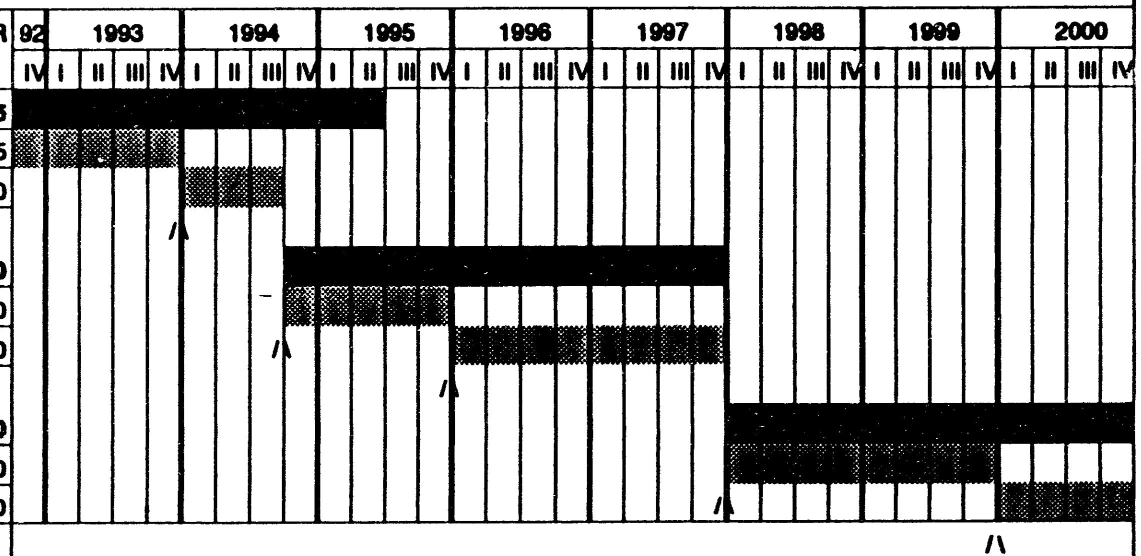
The original project schedule is shown in Figure 6. Construction is scheduled to begin in January 1996 and the three-year test period is scheduled to begin two years later. Because the Power Sales Agreement is not in effect, it will be difficult to start construction as scheduled.

Date: 08/24/93

TOMS CREEK PROJECT

SCHEDULE BASELINE

PROJECT PHASES	B P *)	Early Dates Start	Early Dates Finish	DUR **)
PHASE I - DESIGN		**09/15/92**	**06/30/95**	**33.5**
Project Definition	1	09/15/92	12/31/93	15.5
Detail Design	2	01/01/94	09/30/94	9.0
PHASE II-CONSTRUCTION		**10/01/94**	**12/31/97**	**39.0**
Procurement/Manufact.	3	10/01/94	12/31/95	15.0
Field construction	4	01/01/96	12/31/97	24.0
PHASE III - OPERATION		**01/01/98**	**12/31/00**	**36.0**
Initial Operation	5	01/01/98	12/31/99	24.0
Final Demonstration	6	01/01/00	12/31/00	12.0
TOTAL PROJECT		**09/15/92**	**12/31/00**	**99.5**



***) BP = Budget Period**

****) DUR = Duration Months**

Λ = Decision Point

File: c:\123r3\newsched

Figure 6. Toms Creek Schedule

REFERENCES

G. A. Chirdon, M. J. Hobson, J. G. Patel, and R. T. Silvonen, "Toms Creek IGCC Demonstration Project", First Annual Clean Coal Conference, Cleveland, OH (1992)

A. Harvath, W. Mojtahedi, and K. Salo, "The Development of a Simplified IGCC Process" Symposium on New Coal Utilization Technologies, Helsinki, Finland (1993)

Session 7
Combined NO_x / SO_2 Control Technologies

Co-Chairs:
Richard A. Hargis,
Pittsburgh Energy Technology Center/
U.S. Department of Energy
Gerard G. Elia,
Pittsburgh Energy Technology Center/
U.S. Department of Energy