Clean Coal Technology

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Tampa Electric Integrated Gasification Combined-Cycle Project

A DOE Assessment

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Disclaimer

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Executive Summary

The U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) program seeks to offer the energy marketplace more efficient and environmentally benign coal utilization technology options by demonstrating these technologies in industrial settings. This document is a DOE post-project assessment (PPA) of a project selected in CCT Round III, the Tampa Electric Integrated Gasification Combined-Cycle Project. DOE provided 49 percent of the $303.3 million project funding under the cooperative agreement. Tampa Electric Company (TECO) expended additional funds that were not covered by the cooperative agreement[1].

Operation of the unit, which is sited at TECO's Polk Power Station near Tampa, Florida, commenced in September 1996. Since completion of the project, TECO has continued to operate the IGCC facility for the production and sale of electricity. Other team members were Texaco Development Corporation[2], gasification technology provider, General Electric Corporation, combined-cycle technology provider, Air Products and Chemicals, Inc., air separation unit provider, Monsanto Enviro-Chem Systems, Inc., sulfuric acid plant provider, and Bechtel Power Corporation, the architect engineer.

The nominal 250 MWe (net) capacity demonstration facility is Unit 1 of the Polk Power Plant, a new station located near Mulberry in south central Polk County, Florida. The power station uses an oxygen-blown, entrained-flow, Texaco coal gasifier integrated with gas clean-up and a highly efficient combined cycle to generate electricity with significantly lower SO_2, NO_X, and particulate emissions than most existing coal-fired power plants. The power plant achieved "first fire" of the gasification system on schedule in July 1996.

Because it is cheap and abundant, coal is an obvious choice as a fuel for the production of electric power in the U.S. However, if coal is to continue its dominant role, ways must be found to improve the efficiency and environmental performance of coal-fired units. One promising approach is IGCC technology. Not only are IGCC plants more efficient, but gasification technology converts the sulfur in the coal to H_2S, which is much easier to remove than SO_2. In addition, because gasification generates CO_2 in a high-pressure fuel-gas stream, it provides the opportunity to relatively easily recover some of the CO_2 for potential sequestration. The TECO project provided an essential step in proving the technical and economic viability of IGCC technology and achieving general acceptance among potential users.

IGCC efficiency of over 40 percent is potentially achievable with advanced turbines and other developments, such as hot gas cleanup. Although a hot gas cleanup system was installed to treat a portion of the synthesis gas (syngas) in the Tampa IGCC project, cold flow tests showed that the design sorbent had insufficient attrition resistance, and this prevented the hot gas cleanup system from being tested. Other factors, such as lower than expected carbon conversion in the gasifier, stress cracking in some of the high temperature heat recovery exchangers which necessitated their removal, a slight capacity deficiency of the air separation unit, and gasifier operation at a lower than optimum temperature for carbon conversion to increase refractory life,

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[1] Additional project cost overruns were funded 100% by the participant for a total project funding of $609.9 million.

[2] In October 2001, Texaco merged with Chevron to form the ChevronTexaco Corporation. In May 2004, ChevronTexaco announced plans to sell its gasification technology to GE Energy.

also reduced efficiency. Thus, the full potential of this technology was not demonstrated, and the efficiency achieved of about 35.4 percent (HHV) was somewhat below the design efficiency of 38.6 percent (HHV). Nevertheless, the ability to operate a large gasifier to produce syngas to fuel a combustion turbine is a major achievement.

In the Tampa Electric IGCC project, a coal/water slurry and oxygen are reacted at high temperature and pressure in a Texaco gasifier to produce a medium-Btu syngas. The syngas, along with entrained fly ash, flows through a radiant heat exchanger and then to a high temperature convective heat-recovery unit, which cools the gas while generating high-pressure steam. The cooled gas is water washed for particulate removal. A hydrolysis unit converts any COS in the syngas into H_2S. After amine scrubbing, the clean syngas is reheated and sent to the power block for combined cycle power generation. Molten slag flows out the bottom of the gasifier and is quenched and solidified in a water-filled sump. H_2S from the amine scrubber is converted to sulfuric acid.

The power block is a General Electric supplied combined cycle system, adapted for syngas fuel operation, consisting of a Frame 7FA Combustion Turbine, capable of firing both No. 2 fuel oil and syngas, and associated generator; a condensing steam turbine and associated generator; and a three-pressure, unfired heat recovery steam generator (HRSG).

Coal from eleven U.S. mines was gasified at Polk Power Station during the five-year demonstration period. Six other fuels were gasified in combination with one another or in various blends with coal from one of the eleven mines. The main reason for testing so many fuels and fuel blends was to identify the fuel which resulted in the lowest cost of electricity. Each fuel or blend provided new insights into IGCC operation and helped demonstrate fuel flexibility.

There was relatively little variation in the syngas produced from the different coals; data from petroleum coke blends is also quite consistent. Although there are statistically significant differences between the syngas from coal and from petroleum coke, the heating values are essentially the same. Thus, if petroleum coke is available at a lower price, it can be substituted for coal without affecting the heating value of the syngas.

Typically, petroleum coke is relatively inexpensive, on a dollars per Btu basis, compared to coal. However, petroleum coke usually has more sulfur than the Polk sulfur removal and recovery system was designed to handle (the environmental permit limits feedstock sulfur to 3.5 percent), so it is necessary to blend petroleum coke with coal with lower sulfur content. A further benefit of blending is that coal ash serves as a flux for vanadium in the petroleum coke.

There was a steady gain in the percentage of time the unit was in service from startup in 1996 through 2000, as initial equipment problems were solved, system improvements were made, and operating personnel became more familiar with the unit. A variety of factors led to a slight drop in performance in 2001, including a scheduled outage for gasifier refractor replacement and combustion turbine hardware inspection, failure of the ASU main air compressor, and an outage to deal with the problem of low carbon conversion.

Because every fuel performs differently in the slurry preparation system, full-scale operation, together with experience, is needed to determine how to best prepare slurry from a particular fuel. Because Polk's air separation unit has a limited supply of oxygen, a high slurry concentration is essential to produce enough syngas for base load operation. Some fuels require an additive to lower viscosity so that high concentration slurries will flow through screens and pump suction piping. Other slurries require an additive to prevent fuel particles from settling in lines and agitated tanks. Slurries made from some fuels also require pH adjustment to minimize erosion/corrosion.

Since fly ash with high carbon content cannot be sold, high carbon conversion is important for efficiency and to minimize fly ash disposal costs. High conversion at high slurry concentration and low operating temperature is ideal, since this extends the gasifier refractory liner life and minimizes oxygen requirement. Minimizing oxygen consumption is particularly important at Polk, since the oxygen supply is limited. Fly ash containing unconverted carbon can be recycled to the gasifier to reduce its carbon content, but this increases the oxygen requirement, since it degrades the quality of the slurry fed to the gasifier. With 100 percent coal, recycling fly ash appears to have only a slight positive impact on overall efficiency, since the energy recovered from the recycled fly ash is offset to a large extent by the incremental auxiliary power to produce the additional oxygen required. With petroleum coke in the fuel blend, the impact of recycle on overall efficiency is greater, since the recycled material has higher carbon content and there is more of it. Because of the problem with low carbon conversion, Texaco cooperated in making several burner design modifications. However, these modifications did not have any statistically significant effect on gasifier performance.

Recycling fly ash increases overall carbon conversion and oxygen consumption. For some coals, recycle causes a significant drop in per-pass carbon conversion, which further increases the oxygen requirement, but for other coals, per-pass conversion improves with recycle, which partially mitigates the additional oxygen requirement. There seem to be several competing factors at work, such as changes in the oxygen/carbon ratio, slag volume, and reactivity of the recycled material. It is likely that the relative importance of these factors changes among fuels in a way that is not as yet fully understood. Thus, a test feeding the design coal is important in establishing a design basis for a new plant.

The Tampa Electric facility achieved compliance with all federal and state regulatory requirements for air, water, and solid waste emissions. Air emissions of SO_2, NO_X, and particulates, as well as volatile organic compounds (VOCs) and CO, were well below the required permit limits. Polk's NO_X emissions are a fraction of those from conventional coal-fired power plants equipped with low-NO_X combustion systems and well within the permitted limit of 0.9 lb/MWh. Particulate emissions are about 5 percent of those from conventional coal-fired power plants equipped with electrostatic precipitators.

The primary solid wastes produced are slag and ammonium chloride salt. Slag produced by the process is a vitrified granular solid that is nonleachable and classified as non-hazardous by the EPA. Slag has commercial applications, such as a sandblasting material, an aggregate in concrete, a roofing material, industrial filler, in road construction, and as a building material. Ammonium chloride salt from the brine concentration system is sent to a landfill, but potential markets are being investigated.

Total worldwide syngas capacity in 2002 was about 43,000 megawatts (thermal). Of the installed capacity, a little more than half is coal, or petroleum-coke-based. There has been a significant increase in gasification activity in the past decade. The impetus for this growth is the increased costs for environmental compliance with conventional pulverized coal-fired units, the drive to improve efficiency, the availability of low-cost alternative feedstocks, and the need to utilize indigenous coal in areas without access to natural gas. The maturation of gasification technologies through completion of several large-scale demonstration projects has made this technology a popular and viable alternative to conventional combustion technology.

Indications are that many new domestic gasification projects will be refinery-based, utilizing petroleum coke and other low-cost refinery by-products to produce power, steam, hydrogen, and chemicals for the refinery, as well as additional power for internal use or export. The Tampa Electric CCT project has developed data to permit evaluation of these applications through a petroleum coke test program. Because of excellent environmental performance, the demonstrated technology should be well suited to refinery-based applications utilizing petroleum coke in areas that have been declared as non-compliant for one or more air emissions. TECO Power Services is in the process of commercializing IGCC technology as part of the Cooperative Agreement with the U.S. Department of Energy.

Capital cost, based on Polk's actual cost escalated to mid-year 2001 and incorporating all the lessons learned at Polk, is about $1,650/kW for a 250 MWe (net) plant. This cost is relatively high, but not surprising given site specific factors at Polk, most of which tend to increase costs, particularly the relative scarcity of water, the inability to discharge any waste water, and the high ambient temperature and relative humidity. A direct capital cost as low as $1,300/kW may be projected for a larger plant in a more favorable situation.

The largest annual operating cost is for fuel, and the vast majority of this cost is for coal/petroleum coke for the gasifier. The only other fuel consumed during normal operation is a small amount of propane for the flare pilot light. Propane is also used to heat the gasifier and sulfuric acid plant during cold startups, and a small amount is used to maintain sulfuric acid plant catalyst bed and decomposition furnace heat during brief outages prior to hot restarts. Although the combustion turbine may be operated on distillate fuel when the gasifier is unavailable, the only allowance for this in the economic analysis is to keep the combustion turbines running during brief syngas interruptions. In addition to fuel, other operating costs include salaries, fringe benefits, catalyst, chemicals, and maintenance. Slag handling and disposal costs are not included. The estimated cost of electricity is 5.9 cents/kWh on a current-dollar basis and 4.6 cents/kWh on a constant-dollar basis for a 500 MWe plant with an estimated investment of $780 million. It was assumed that supplemental fuel was burned 2 percent of the on-stream time.

This project demonstrated the technical feasibility of commercial-scale IGCC technology. Since startup in September 1996, the plant has met its objective of generating low-cost electricity in a safe, reliable, and environmentally acceptable manner. On September 30, 2001, Polk Power Station completed its fifth year of commercial operation. The plant continues to operate base loaded as a key part of Tampa Electric Company's generation fleet.

The facility demonstrated its ability to operate on a wide variety of coals. However, coal properties, such as sulfur content, chlorine content, and ash level and composition, affect performance. Therefore, in designing a new plant, actual operating data on the design coal are crucial to avoiding problems, such as insufficient sulfur or chloride handling capacity.

The most significant problem encountered in this project was the lower than expected carbon conversion in the gasifier, which required recycling fly ash to the gasifier to increase carbon conversion and reduce the carbon content of the fly ash. However, recycling fly ash increased oxygen requirement. Improvements in carbon conversion would significantly advance this technology. The inability to operate the hot gas cleanup system due to not having an attrition resistant sorbent prevented gathering data on this potential efficiency improving technology.

Approximately fifty-fifty blends of petroleum coke and coal work well. The low chlorine content of the coke allows use of high chlorine content coal, while lower sulfur coals can compensate for the typically high sulfur in the petroleum coke. In addition, the ash in the coal acts as a fluxing agent for the vanadium in the coke.

Overall, this was a successful project that demonstrated that an IGCC power plant can be successfully built and operated. It also provided much valuable information that will permit the design and operation of more efficient IGCC systems in the future.

I. Introduction

The U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) program seeks to offer the energy marketplace more efficient and environmentally benign coal utilization technology options by demonstrating these technologies in industrial settings. This document is a DOE post-project assessment (PPA) of a project selected in CCT Round III, the Tampa Electric Integrated Gasification Combined-Cycle Project, initially described in a Report to Congress [DOE, 1991].

Integrated Gasification Combined Cycle (IGCC) is a method for increasing efficiency and decreasing pollutant emissions from coal-fired power generation facilities. The desire to demonstrate the use of IGCC for the economical and environmentally friendly production of electricity prompted Tampa Electric Company (TECO) to submit a proposal to DOE. In March 1991, TECO entered into a cooperative agreement with DOE to conduct this project. DOE provided 49 percent of the $303.3 million project funding under the cooperative agreement. TECO expended additional funds that were not covered by the cooperative agreement[3].

Operation of the unit, which is sited at TECO's Polk Power Station near Tampa, Florida, commenced in September 1996. Although the CCT project was completed in October 2001, TECO continues to operate the IGCC facility for the production and sale of electricity. The independent evaluation contained herein is based primarily on information from TECO's Final Report [Tampa Electric Company, 2002], as well as other references cited.

[3] Additional project cost overruns were funded 100 percent by the participant, for a total project funding of $609.9 million.

II. Project/Process Description

A. Project Description

TECO (the Participant) is an investor owned electric utility, headquartered in Tampa, Florida. TECO is the principal wholly owned subsidiary of TECO Energy, Inc., an energy related holding company. Another subsidiary of TECO Energy, TECO Power Services Corporation (TPS), which owns and operates several natural gas and coal-fired power plants, provided project management services to Polk Power Station during the design, construction, and startup phases. Other team members were Texaco Development Corporation[4], gasification technology provider, General Electric Corporation, combined-cycle technology provider, Air Products and Chemicals, Inc., air separation unit provider, Monsanto Enviro-Chem Systems, Inc., sulfuric acid plant provider, and Bechtel Power Corporation, the architect engineer.

The demonstration facility is Unit 1 of the Polk Power Plant, a new station located near Mulberry, in south central Polk County, Florida. The 4,300-acre site is about 45 miles southeast of Tampa and 17 miles south of Lakeland, in the heart of central Florida's phosphate mining region. The Polk site is on a tract of land that had been previously mined for phosphate rock and was redeveloped and revegetated by TECO for this project. Polk Power Station is a nominal 250 MWe (net) IGCC power plant. The power station uses an oxygen-blown, entrained-flow, coal gasifier integrated with gas clean-up systems and a highly efficient combined cycle to generate electricity with significantly lower SO_2, NO_X, and particulate emissions than most existing coal-fired power plants.

The project was selected under Round III of DOE's Clean Coal Technology Program in December 1989, based on an air-blown gasifier to be located at a site near Tallahassee, Florida. After selection, the project was revised to incorporate newer, more efficient, oxygen-blown gasification and combined cycle technology at a relocated site. An independent site selection committee consisting of community representatives selected the current site, an abandoned phosphate mine in southwestern Polk County, Florida. The DOE Cooperative Agreement, originally awarded in March 1991, was modified in March 1992 to incorporate these changes. Detailed design began in April 1993, and site work began in August 1994. The power plant achieved first fire of the gasification system on schedule in July 1996. The unit was placed into commercial operation on September 30, 1996.

B. Need for the Technology Demonstration

Because it is cheap and abundant, coal is an obvious choice as a fuel for the production of electric power in the U.S. However, if coal is to continue its dominant role, ways must be found to improve efficiency and environmental performance of coal-fired units. One promising approach is IGCC technology. Not only are IGCC plants more efficient, but gasification technology converts the sulfur in the coal into H_2S, which is much easier to remove than SO_2. In addition, because gasification generates CO_2 in a high-pressure fuel-gas stream, it provides the

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[4] In October 2001, Texaco merged with Chevron to form the ChevronTexaco Corporation. In May 2004, ChevronTexaco announced plans to sell its gasification technology to GE Energy.

opportunity to relatively easily recover some of the CO_2 for sequestration, should future regulations require that this be done. However, because IGCC is a relatively new concept and involves technology with which most power producers are unfamiliar, many producers are not willing to take the financial risks associated with implementing IGCC. Therefore, demonstration projects, such as the TECO project, are essential for proving the technical and economic viability of IGCC technology and achieving general acceptance among potential users.

C. Potential of the Technology

IGCC holds great promise for improving the efficiency of electric power production from coal while simultaneously reducing pollutant emissions. An efficiency of over 40 percent (HHV) is potentially achievable with advanced turbines and other developments, such as hot gas cleanup. Although a hot gas cleanup system was installed to treat a portion of the synthesis gas (syngas) in the Tampa IGCC project, cold flow tests showed that the design sorbent had insufficient attrition resistance, and this prevented the hot gas cleanup system from being tested. Other factors, such as lower than expected carbon conversion in the gasifier, stress cracking in some of the high temperature exchangers which necessitated their removal, a slight capacity deficiency of the air separation unit, and operating the gasifier at a lower temperature than optimum for carbon conversion to increase refractory liner life, also reduced efficiency. Thus, the full potential of this technology was not demonstrated, and the efficiency achieved of about 35.4 percent (HHV) was somewhat below the design efficiency of 38.6 percent (HHV). Nevertheless, the ability to operate a large gasifier to produce syngas to fuel a combustion turbine is a major achievement. This technology also has the potential to recover sulfur in the fuel as a useful by-product (elemental sulfur or sulfuric acid) rather than a sludge that has to be disposed of in a landfill. The potential also exists to sell the slag produced in the gasifier for a variety of uses.

D. Technology Description

Figure 1 presents a schematic diagram of the Tampa Electric IGCC project. A coal/water slurry and oxygen are reacted at high temperature and pressure in a Texaco gasifier to produce a medium-Btu syngas. The syngas, along with entrained fly ash, flows through a radiant heat exchanger and then to a high temperature convective heat-recovery unit, which cools the gas while generating high-pressure steam. The cooled gas is water washed for particulate removal. A hydrolysis unit converts any COS in the syngas into H_2S. After amine scrubbing, the clean syngas is reheated and sent to the power block for combined cycle power generation. Molten slag flows out the bottom of the gasifier and is quenched and solidified in a water-filled sump. Major system components are discussed in more detail in the following sections.

1. Coal Receiving and Storage

Coal is received by barge at TECO's Big Bend Station coal yard. The coal is typically transported to the Polk Plant in covered, bottom-dump, tandem trailers, each with a 26-ton payload (95 trucks per day are required at full operating rate). At the Polk Station, the trucks off-load into an above-grade unloading hopper in a covered unloading structure. The top of the hopper contains sprays that control dust emissions. Belt feeders transfer coal from the hopper onto an enclosed 400 ton/hr unloading conveyor, which transports the coal to two 5,000 ton storage silos. A dust collection system at the top of the silos controls dust. Each silo is equipped with a 400 ton/hr reclaim feeder and reclaim conveyor to deliver the coal to the 200 ton surge bin at the top of the coal grinding structure.

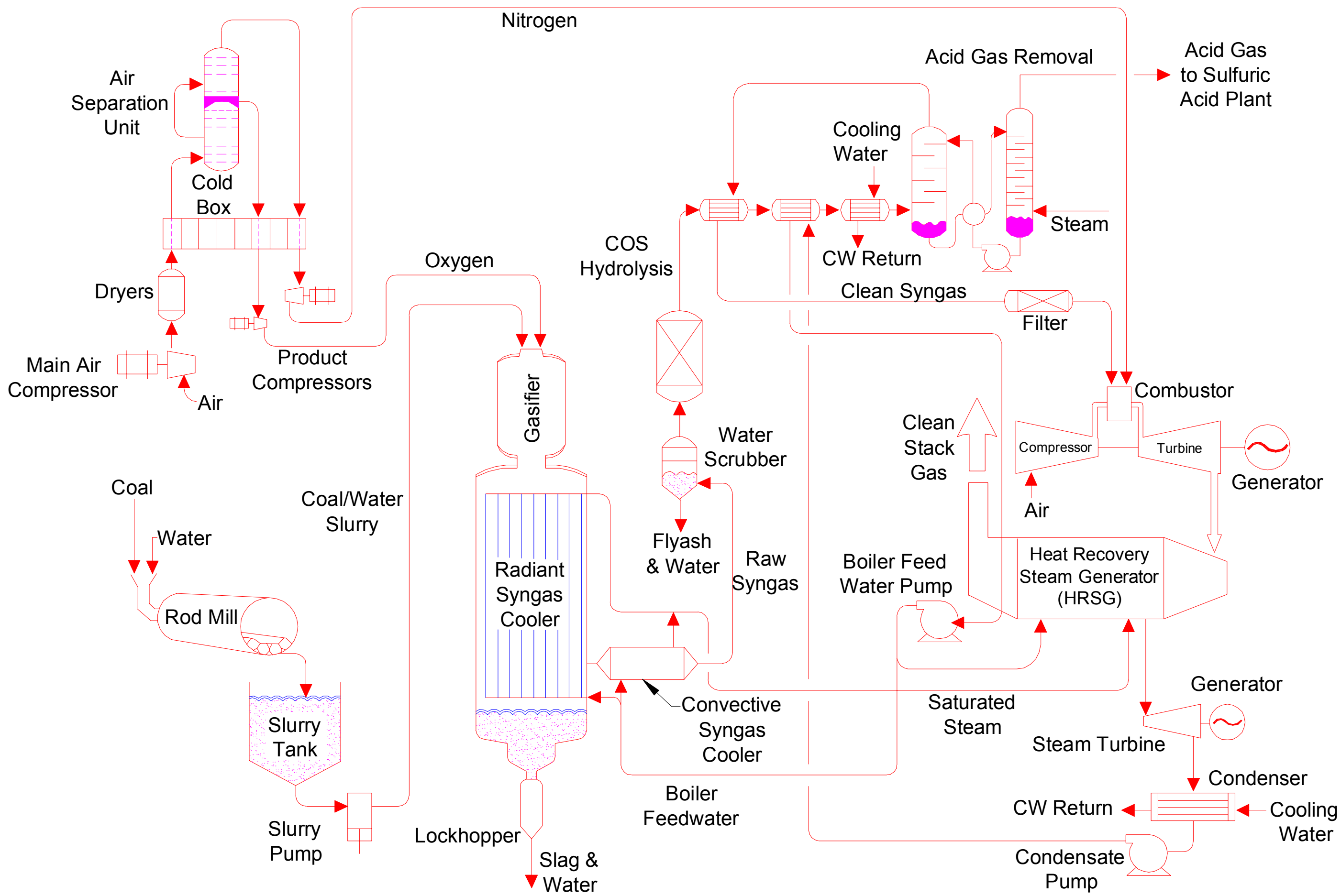

Figure 1 Schematic of the Tampa Electric IGCC Project

2. Slurry Preparation

The slurry preparation system consists of two grinding trains, each of which can process up to 60 ton/hr of coal (as received basis), which is 55 to 60 percent of the gasifier's requirement at full load. For each train a weigh feeder meters the coal into a rod mill that is also fed with process water containing recycled fines. Additives to reduce the viscosity of the slurry and/or adjust its pH may also be fed.

A coarse trommel screen at the discharge end of the mill rejects pieces of broken rods. The slurry passes through the trommel screen and falls into an agitated tank from which a centrifugal pump delivers the slurry to a finer screen at the top of a large run tank. A density meter provides a continuous indication of slurry concentration (normally 62 to 68 percent solids). Slurry storage consists of two agitated tanks, which together can provide almost eight hours of gasifier operation. The slurry feed system is a single, three-cylinder Geho diaphragm pump with a variable frequency drive that can deliver up to 500 gpm at 500 psig.

3. Air Separation Unit

Figure 2 is a general flow diagram of the Air Separation Unit (ASU). The main air compressor has four stages with inter-cooling between each stage and an aftercooler. Plant controls automatically throttle the compressor's inlet guide vanes to supply just enough air to the ASU to meet the gasifier's oxygen requirements. The compressed air goes to a temperature swing adsorption (TSA) system for removal of water vapor and traces of CO_2, which would otherwise freeze in the cryogenic equipment and cause plugging. Regeneration of the adsorbent beds is accomplished with dry nitrogen drawn from the main nitrogen product stream.

The dry, CO_2-free air enters the cryogenic section of the plant through the main heat exchanger, where it is cooled by diluent nitrogen, gaseous oxygen, and high purity gaseous nitrogen. Cryogenic distillation occurs in a cold box in a standard two column arrangement, one column operating at elevated pressure, the other at reduced pressure. After removal of a small slipstream that is sent to the sulfuric acid plant, the main oxygen stream is compressed and sent to the gasifier.

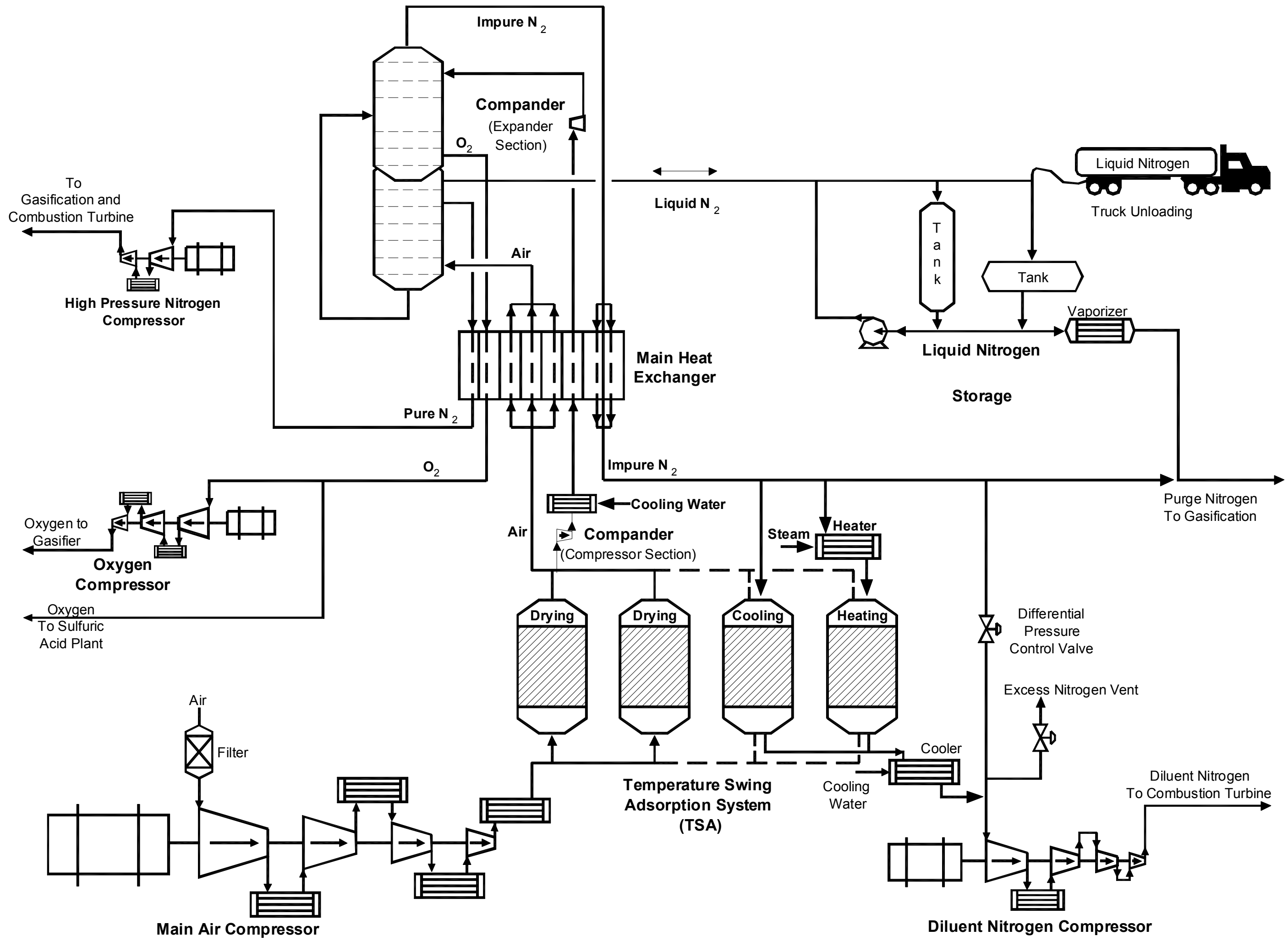

Figure 2 Flow Diagram of Air Separation Unit

Diluent nitrogen gas is the largest product stream and normally contains about 1.5 percent oxygen. Some nitrogen is extracted for purging and blanketing in the gasification plant, and additional gas is drawn off for regeneration of the TSA unit, but this gas is returned to maximize diluent nitrogen recovery. The nitrogen compressor delivers nitrogen to the combustion turbine for NO_x abatement and power augmentation. High-pressure nitrogen (at a purity of 50 ppm O_2) is continuously withdrawn for purges and equipment blanketing in the power block's fuel transfer system and for purges, blanketing, and sootblowing in the gasification plant.

The plant also produces a small stream of liquid nitrogen, which is stored in two liquid nitrogen tanks and used during ASU outages to supply low pressure purge nitrogen to the gasification plant. Liquid nitrogen is also pumped into the columns for faster ASU plant startup. A liquid nitrogen truck unloading facility enables recharging the tanks during extended ASU outages.

4. Texaco Gasifier

The Polk IGCC uses a Texaco oxygen-blown, entrained-flow, gasification system with full heat recovery. The general arrangement is shown in Figure 3. Coal slurry from the slurry feed pump and oxygen from the ASU are fed to the gasifier through a series of valves which operate in a carefully determined sequence to start the gasifier and provide positive isolation during shutdown. The oxygen and slurry combine in the process feed injector, which is designed to intimately mix and disperse the fuel and oxidant into the gasifier chamber. The gasifier's normal operating pressure is 375 psig, and an internal refractory liner protects the carbon steel shell from the operating temperature of 2,300 to 2,700 ^{o}F. An elaborate skin temperature sensing system alerts operators if the refractory liner fails.

The coal slurry and oxygen interact in the gasifier to produce three products: syngas, slag, and fly ash. The raw syngas consists primarily of H_2, CO, H_2O, and CO_2, with smaller amounts of H_2S, HCl, COS, CH_4, Ar, NH_3, and N_2. After moisture has been removed, the heating value of the syngas is about 250 Btu/scf, which accounts for 70 to 75 percent of the heating value of the original fuel.

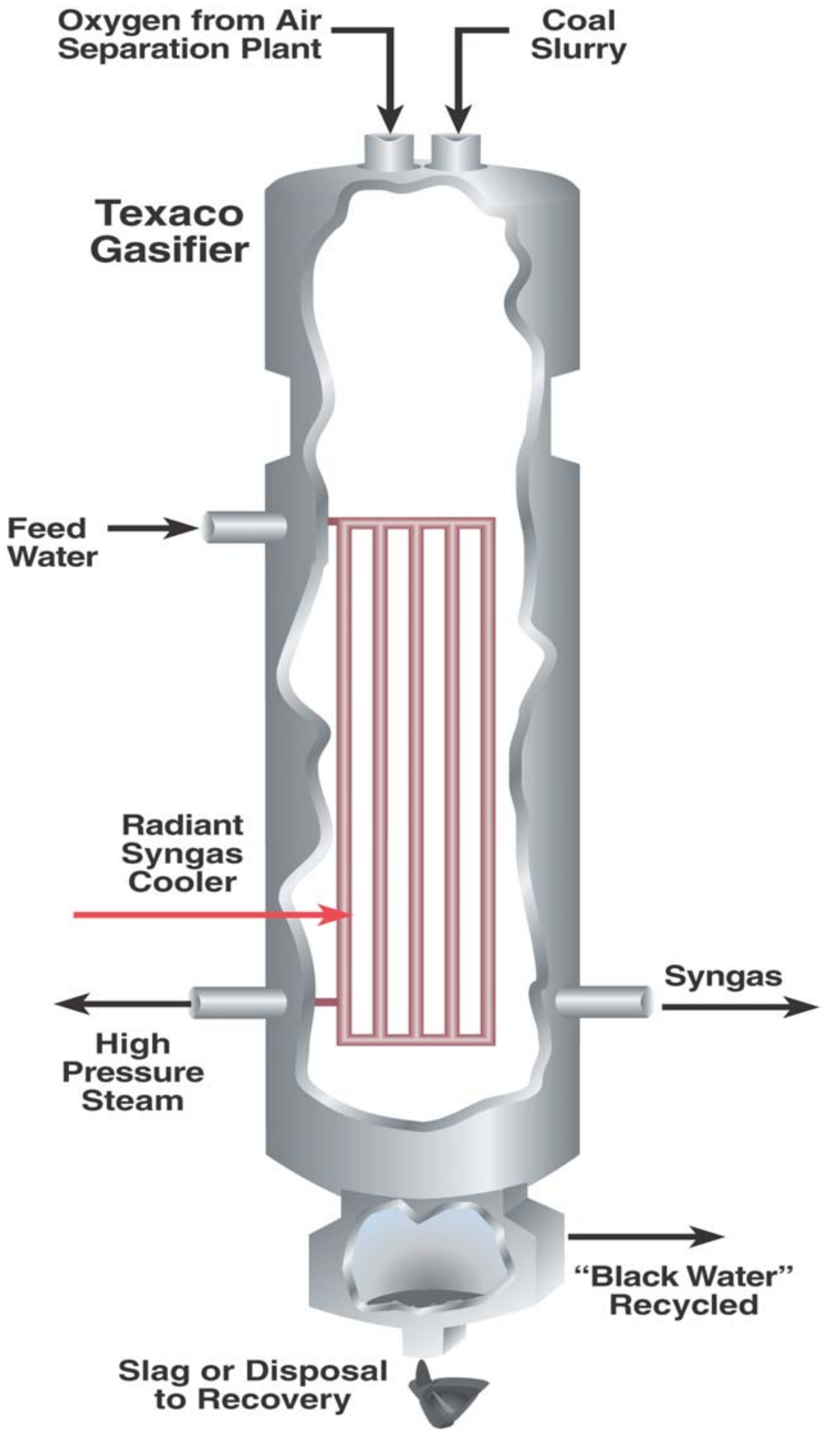

Figure 3 Flow Diagram of Texaco Gasifier

Part of the mineral matter in the fuel melts at the elevated temperature in the gasifier and flows down the refractory-lined walls as slag, which is quenched in a water bath and solidified into an inert glassy frit with very low carbon content. Some of the coal is not completely gasified and forms char particles, referred to as “fly ash,” although the physical characteristics are quite different from conventional fly ash. This fly ash, containing a considerable amount of residual carbon plus some of the mineral matter from the fuel, is transported out of the gasifier with the syngas.

The gasifier exit gas stream flows through a radiant syngas cooler lined with a ring of tubes connected in a configuration called a waterwall, in which 1,650 psig steam is generated. In this cooler, heat is transferred primarily by radiation, and the waterwall serves to protect the shell from the hot gas. The cooler was originally configured with an elaborate system of 122 sootblower lances, but experience showed that the system remained much cleaner than expected and only four of the sootblowers were needed. Although the design exit temperature is 1,400 ^{o}F, the actual exit temperature is consistently below 1,350 ^{o}F. The radiant syngas cooler typically recovers anywhere from 250 to 300 million Btu/hr (12 to 15 percent of the fuel’s heating value). Before exiting the cooler, the syngas passes over the surface of a pool of water, which collects virtually all of the slag and about half of the fly ash.

The syngas leaves the bottom of the radiant syngas cooler with the flow equally split between two water-cooled transfer ducts. It was originally intended to test hot gas cleanup, so two exits were provided, one for conventional cold gas cleanup and the other for the hot gas cleanup system. Because of insufficient attrition resistance of the sorbent, it was decided not to operate the hot gas cleanup system. Commercial plants would have only one cleanup system and, hence, only one exit duct. The transfer duct is in the form of a double pipe heat exchanger with the gas in the inner pipe. The annulus contains medium pressure circulating boiler feed-water and generates some medium pressure steam.

A convective syngas cooler is located at the end of each transfer duct (see Figure 4). High pressure boiler feed-water circulates through the shell side by natural convection, generating additional 1,650 psig steam. Syngas leaves these coolers at 700 to 750 ^{o}F. The transfer ducts/coolers recover an additional 3 to 4.5 percent of the coal’s heating value. The convective syngas coolers are subject to periodic plugging. Originally, high temperature heat recovery exchangers, called clean gas heaters, were located at the exits of the convective syngas coolers but had to be removed because of damage from plugging and cracking. Now, the gas leaving the convective syngas coolers goes directly to the syngas scrubbers.

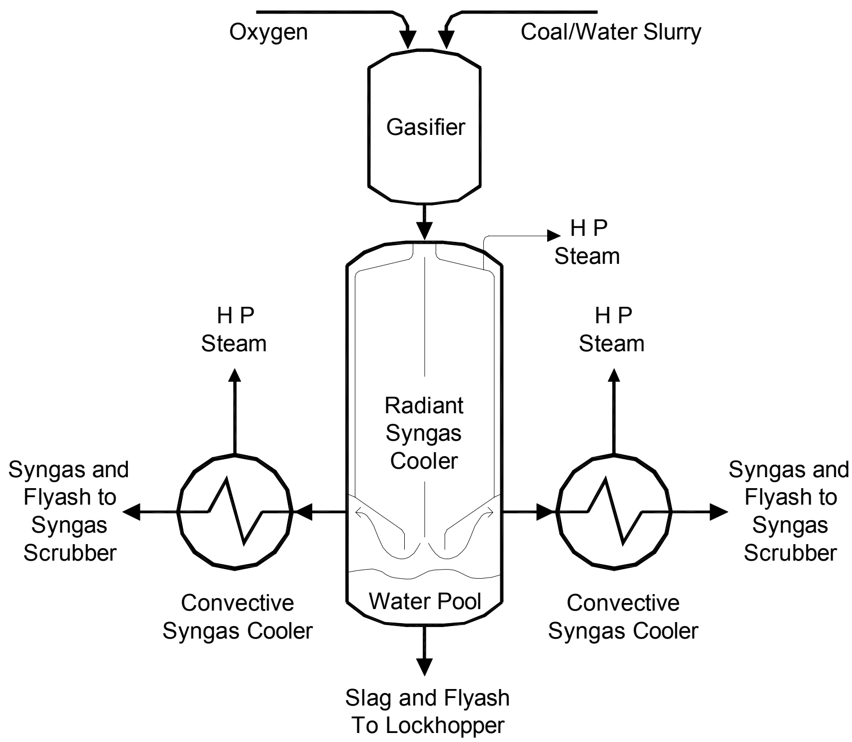

Figure 4 Flow Diagram of Syngas Cooling System

5. Syngas Cleanup

Syngas leaves the two convective syngas coolers at 700 ^{o}F and enters the syngas scrubbers. Three water/gas contact steps in series remove most of the particulates and HCl from the gas. The water-saturated gas leaves the scrubbers through demisters. The gas streams from the two scrubbers then combine and flow to a knockout drum that contains one gas/water contact step and a demister and then to the COS hydrolysis unit.

The COS hydrolysis unit, which was added in 1999, consists of a super-heater followed by a reactor. In the reactor, 85 to 95 percent of the COS is converted to H_2S according to the reaction:

$$COS + H_2O \rightarrow H_2S + CO_2$$

This hydrolysis step is necessary because about 5 percent of the sulfur in the coal is converted to COS in the gasifier. The amine scrubber does not absorb COS, and failure to remove COS from the syngas would result in exceeding the sulfur emissions permit limit. Following COS hydrolysis, the gas is cooled to near ambient temperature by a series of three heat exchangers, each followed by a knockout drum to remove the process condensate formed.

6. Acid Gas Removal

The acid gas removal system uses a water solution containing 25 to 50 percent methyldiethanol amine (MDEA) to remove 98.5 to 99.5 percent of the H_2S from the syngas. The syngas is introduced at the bottom of a trayed absorber, and the MDEA is introduced at the top. As the gas and MDEA flow countercurrent to each other, the MDEA absorbs the H_2S. MDEA from the bottom of the absorber flows to the top of the stripper, another trayed column, where the solvent is heated to release the H_2S. The hot solvent from the bottom of the stripper is cooled first by preheating the incoming MDEA and then with cooling water. The cooled MDEA flows to a storage tank from which it is pumped back to the absorber. The H_2S-containing stripper-overhead gas is sent to the sulfuric acid plant.

MDEA also removes CO_2 from the syngas. This is undesirable because the CO_2 helps the combustion turbine by increasing power output and efficiency and reducing flame temperature for NO_X abatement, and high CO_2 removal increases the volume of the acid gas stream to the sulfuric acid plant. A solvent's preferential removal of H_2S over CO_2 is referred to as H_2S selectivity. At Polk, testing has indicated that the independent variables impacting selectivity are solvent circulation rate, MDEA concentration in the circulating solvent, contact time between the solvent and gas, and absorber temperature. The high solvent circulation rate required for high selectivity increases low pressure steam consumption in the stripper, which reduces overall cycle efficiency.

Trace compounds in the syngas, mostly formic acid vapor produced in the COS hydrolysis unit, react with MDEA to form heat stable salts that, unlike the complex formed with H_2S, cannot be regenerated by heating. If not removed, these salts eventually tie up all the MDEA, making it ineffective for H_2S removal. An ion exchange unit was installed to regenerate the heat stable salts.

The clean syngas from the MDEA absorber passes through a knockout drum with a demister to remove solvent mist. The gas is then heated in the clean gas pre-heater and passed through a 10 micron cartridge filter and a strainer immediately upstream of the combustion turbine's fuel control valves to prevent particulates from entering the turbine.

7. Sulfuric Acid Plant

Most IGCC plants convert recovered H_2S into elemental sulfur in a Claus plant. However, because of the large market for sulfuric acid sales to the local fertilizer industry in central Florida, at Polk, a sulfuric acid plant was installed (see Figure 5). The H_2S is burned to form SO_2 in the decomposition furnace which operates under a slight vacuum. This furnace also processes the flash gas stream from the black-water vacuum flash drum and converts the ammonia into N_2 and H_2O. This is the most economical disposition for the ammonia, since the quantity is too small (less than 400 lb/hr) to be economically recovered for commercial sale. If burned directly, a significant fraction of the ammonia would be converted into NO_X.

A waste heat boiler at the outlet of the decomposition furnace cools the gas, generating medium pressure steam. The gas is further cooled in a cooling tower, which produces a small weak acid waste stream that is neutralized and discharged to the cooling pond. The cooled gas goes to a drying tower. SO_2 is converted to SO_3 in three catalytic reactors, using 95 percent purity oxygen from the ASU. Gas goes from the second reactor to the inter-pass absorbing tower and from the third reactor to the final absorbing tower. In the absorbing towers, SO_3 reacts with the water in 98 percent sulfuric acid to form H_2SO_4. Since this incrementally raises the concentration of the sulfuric acid, water is added as

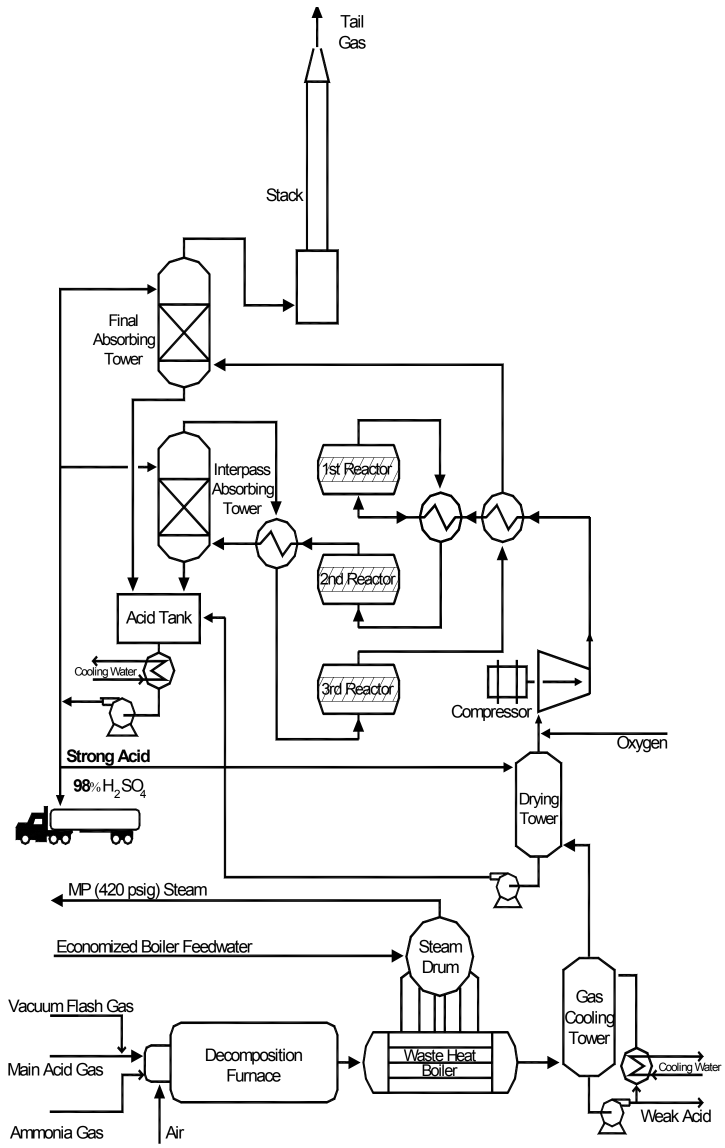

Figure 5 Flow Diagram of Sulfuric Acid Plant

required to maintain a concentration of 98.5 percent. Polk produces 200 ton/day of sulfuric acid when operating with fuels containing 3.5 percent sulfur (dry basis). The sulfuric acid plant is very efficient, converting over 99.5 percent of the incoming H_2S into H_2SO_4. The tail gas from the final absorbing tower, containing 150 to 250 ppm SO_2, is discharged through a dedicated stack.

8. Slag, Fly ash, Brine, and Process Water Handling

Figure 6 shows the major slag, fly ash, brine, and process water streams. As the syngas makes a sharp turn at the bottom of the radiant syngas cooler (RSC), all of the slag and about 40 percent of the fly ash from the gasifier separate and fall into a water pool, referred to as the RSC sump. Makeup to the sump is particulate- and chloride-free process condensate from the low temperature gas cooling section of the gasification plant. A steady blowdown stream from the sump, known as black water because it contains a significant amount of fly ash, goes to a vacuum flash system.

The slag and the fly ash picked up in the sump settle and pass through a slag crusher en route to a lockhopper. The lockhopper discharges 3 to 4 times per hour to a drag flight conveyor. As the lockhopper dumps, it is flushed with stripped condensate (process condensate from which most of the ammonia has been removed by steam stripping). Since chloride and ammonia render slag unmarketable, only streams free of chloride and relatively free of ammonia are used as makeup to the sump and lockhopper.

The drag flight conveyor deposits the slag and fly ash onto a washed screen. The coarse material from the screen (glassy slag), containing 10 to 15 percent combustible material when coal is the feedstock, has been sold to the cement industry. The water and the fine solids that pass through the screen (fly ash containing 30 percent carbon or more) constitute black water that is pumped to the settler feed tank.

The 60 percent of the fly ash from the gasifier that isn't collected in the sump travels with the syngas through the convective syngas coolers to the syngas scrubbers, where fly ash and HCl are removed by intimate contact with water. The black water blowdown streams from the two scrubbers enter the vacuum flash drum, along with the sump black water stream. The major make-up water stream to the syngas scrubbers is grey water (black water from which the particulates have settled). A small process condensate stream performs a final polishing in trays at the top of the scrubber to improve removal of particulates and chlorides from the syngas. The syngas leaves the scrubbers at 330 ^{o}F and 350 psig, saturated with water vapor.

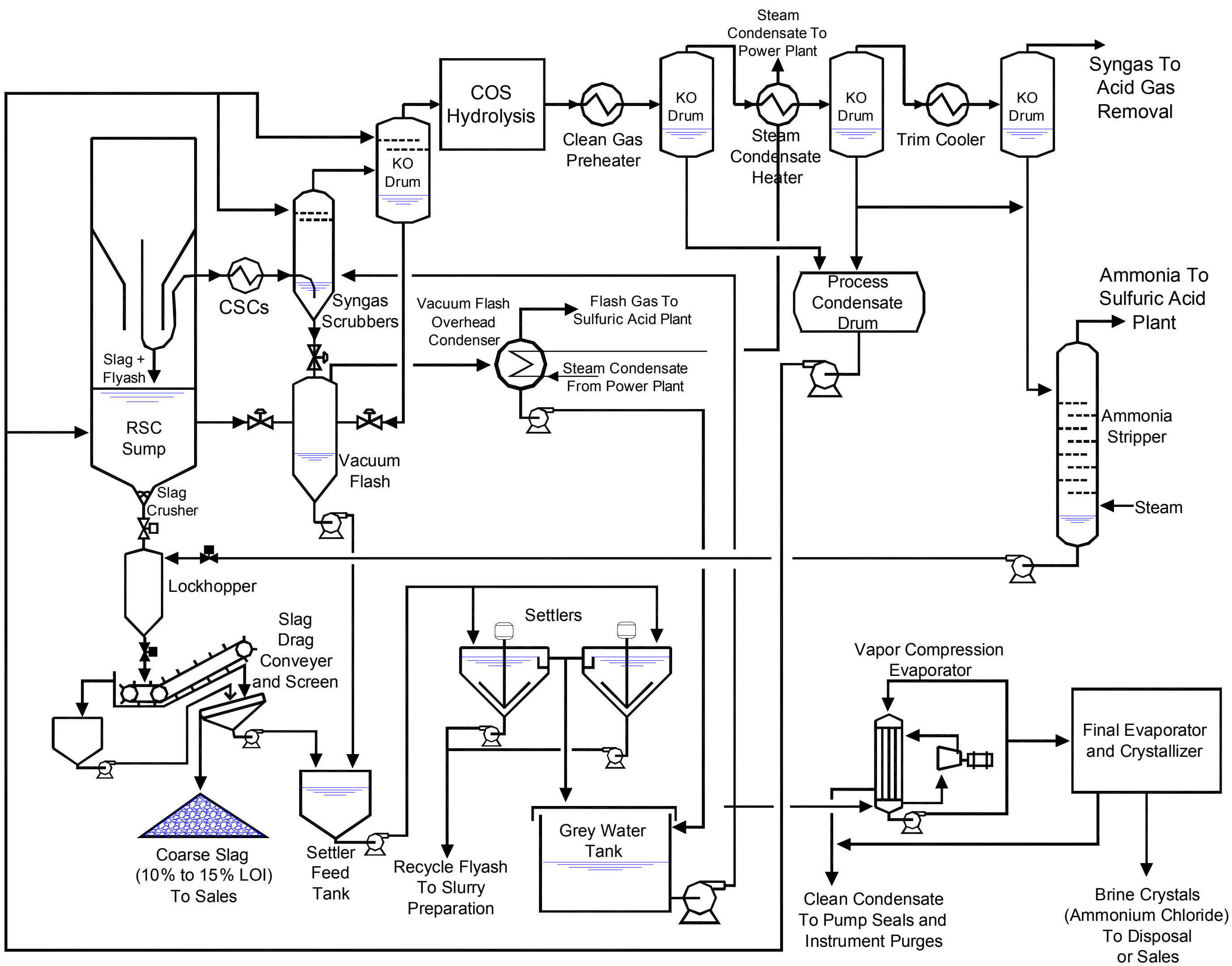

Figure 6 Slag, Fly Ash, Brine, and Process Water Handling

Four black water streams feed the vacuum flash drum, which operates at a pressure of 7.5 psia: the sump blowdown, a blowdown stream from each of the two scrubbers, and the blowdown from the knockout drum before the COS hydrolysis unit. The flashed steam is condensed by preheating steam turbine condensate. A vacuum pump delivers the non-condensable gases, mostly CO_2, to the sulfuric acid plant. The vacuum flash drum bottom stream is pumped to the settler feed tank, where it is mixed with the black water from the coarse slag screen. The black water from the settler feed tank, containing 5 to 10 percent solids, is distributed to two gravity settlers. The settlers concentrate the fly ash into bottom streams that are normally sent to the slurry preparation area for recycling to the gasifier.

The settler overflow streams are relatively particulate free. Most of the grey water is recycled to the syngas scrubbers, but a side-stream is sent to the brine concentration system. This prevents dissolved solids, particularly chlorides, from building up in the grey water to a concentration that would become corrosive. The brine concentration system consists of two main steps, first a vapor compression cycle, where most of the water is efficiently evaporated and, second, a final evaporation and crystal removal step. The condensate is returned to the process for pump seals and instrument tap flushes. The salt, mostly ammonium chloride produced at a rate of about 20 tons/month, is presently sent to a landfill, but potential markets are being investigated.

The final part of the process water system is process condensate. The syngas from the scrubbers contains slightly over 30 percent water vapor, most of which condenses when the temperature is reduced to near ambient. This condensed water is referred to as process condensate. The process condensate from the higher temperature exchangers contains very little ammonia. It is sent to the scrubbers and knockout drum for particulate removal and to the sump as makeup via the process condensate drum. The process condensate from the cooler exchangers contains most of the ammonia produced in the gasifier. It is routed to the ammonia stripper, where steam stripping removes the ammonia. The ammonia gas flows to the sulfuric acid plant for conversion to nitrogen gas plus water vapor. The ammonia stripper bottom is referred to as stripped condensate and is used to flush the lockhopper.

9. Power Block

The power plant is a General Electric combined cycle adapted for syngas fuel operation. GE provided the engineering, manufacture, and supply of the following equipment:

> One Frame 7FA Single Shaft Combustion Turbine with 7221 Multi Nozzle Quiet Combustors, capable of firing No. 2 fuel oil as well as syngas, and associated 229,741 KVA hydrogen cooled generator
>
> One tandem compound, double flow condensing steam turbine with one uncontrolled extraction and associated 156,471 KVA hydrogen cooled generator
>
> One three-pressure, unfired Heat Recovery Steam Generator (HRSG) with integral deaerator (fabricated by Vogt under contract to GE)

a. Combustion Turbine

Filtered ambient air, at a rate of 3 million pounds per hour (40 million scf/hr), enters the combustion turbine compressor. The compressor is a multi-stage, axial machine that requires approximately 200,000 shaft horsepower, making it by far the largest “auxiliary” power consumer in the facility. Most of the air is used for fuel combustion, but a significant fraction is diverted to cooling the turbine, after which it joins the combustion products.

The fuel for the combustion turbine is clean superheated syngas. Diluent nitrogen from the air separation plant is used for NO_X abatement (by lowering combustion temperature) and power augmentation when firing syngas. The combustion turbine's startup and backup fuel is low sulfur No. 2 distillate oil. When firing distillate fuel, NO_X emissions are controlled by de-mineralized water injection.

The combustion products, mixed with the air used to cool the combustion turbine, pass through the expansion turbine and produce approximately 475,000 shaft horsepower. Of this, 200,000 HP is consumed by the compressor; 257,000 HP is used by the hydrogen-cooled generator to produce 192 MW; and the rest is consumed by generator and bearing losses. The exhaust gas leaves the final turbine stage at 1,066 ^oF through an exhaust plenum into the HRSG.

b. Heat Recovery Steam Generator

The HRSG recovers heat from the combustion turbine exhaust to preheat boiler feedwater (BFW) and to produce and superheat steam for the generation of additional power in the steam turbine. The HRSG is a three-pressure level, reheat, natural circulation design. Its configuration, along with that of the steam turbine, is shown in Figure 7. The 1,066 ^oF combustion turbine exhaust gas enters the superheater and reheater sections of the HRSG, which heat the high pressure (HP) and intermediate pressure (IP) steam to 1,000 ^oF.

Next is the HP evaporator which generates 165,000 lb/hr of 1,415 psig steam. This is 25 to 30 percent of the HP steam produced in the plant. The syngas cooler HP steam flows into the HRSG HP drum. A small IP steam superheater is next, followed by the hottest HP economizer, which finishes preheating boiler feedwater for the HRSG HP evaporator and the syngas coolers.

The IP evaporator generates about 50,000 lb/hr of 370 psig steam. The gasification plant's IP steam, which is generated at 420 psig, flows to the HRSG IP drum and the HRSG superheaters and turbine. The IP evaporator is followed by three economizer sections that preheat HP and IP boiler feedwater.

Next, low pressure (LP) steam is generated in the LP evaporator for the air separation plant and the gasification plant. Finally, BFW is preheated in the last HRSG section for additional heat recovery. The temperature of the exhaust gas to the stack is typically anywhere from 310 to 340 ^oF.

c. Steam Turbine

The steam turbine configuration is shown on Figure 7. It is a double flow reheat unit with low pressure crossover extraction. The steam turbine generator is designed specifically for highly efficient combined cycle operation with nominal turbine inlet conditions of approximately 1,450 psig

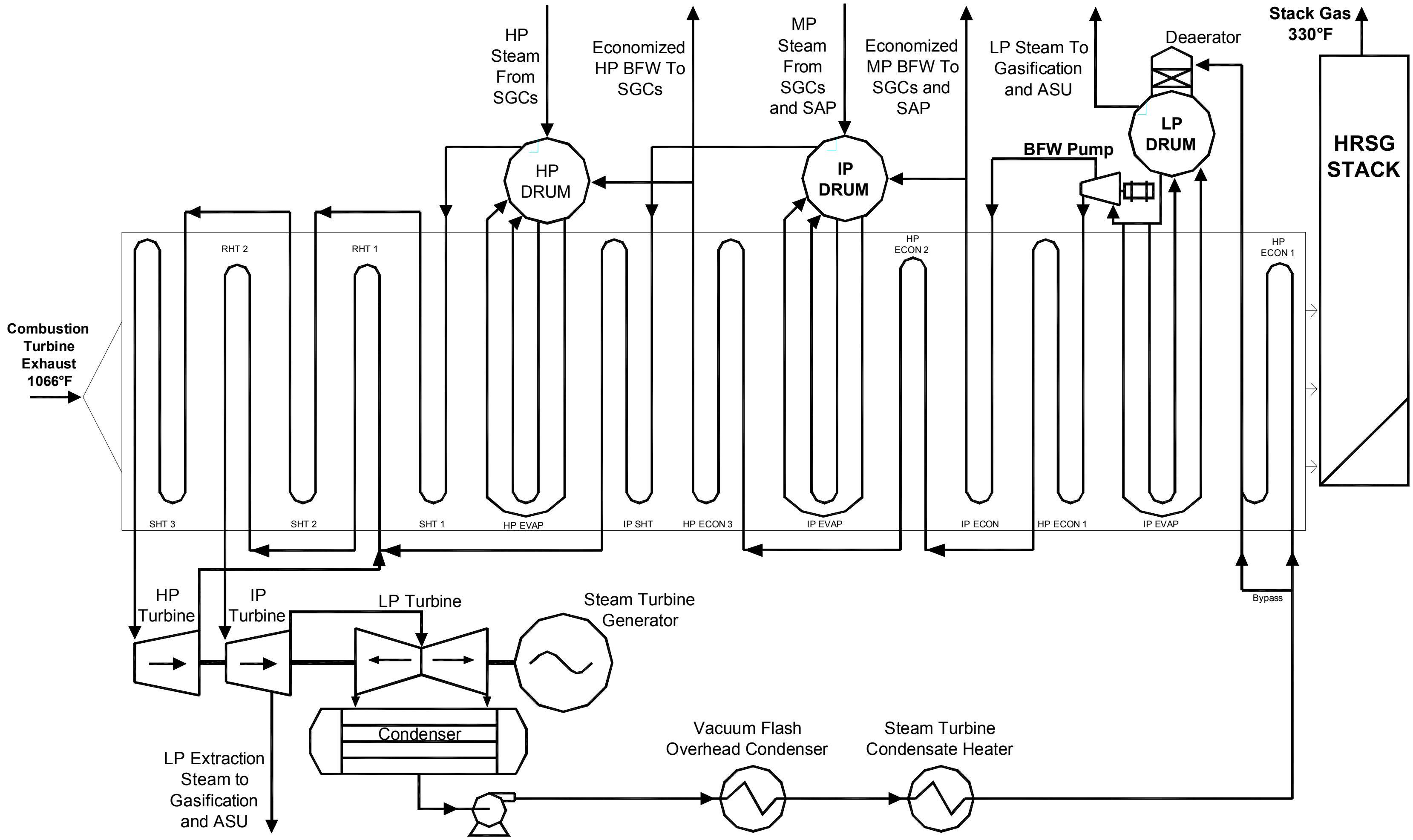

Figure 7 Flow Diagram of Heat Recovery Steam Generator and Steam Turbine

and 1,000 ^{o}F with 1,000 ^{o}F reheat inlet temperature. Output during normal full load operation on syngas fuel is 120 to 135 MWe, depending on ambient temperature and steam production and consumption in the gasification plant. The outlet from the last stage of the turbine is condensed by heat exchange with circulating water from the plant cooling water reservoir.

E. Project Objective and Statement of Work

According to the statement of work, the objective of this demonstration project was to design, construct, and operate a 250 MWe IGCC system which is potentially capable of providing high performance, cost competitive, environmentally compliant electric power from coal. Another objective was to develop data which will demonstrate that, compared to existing and future conventional coal-burning power plants, such an IGCC system can be the technology of choice for coal utilization because significant reductions of SO_2 and NO_X emissions can be achieved. As a further objective, the integrated performance was expected to demonstrate the reliability, cost effectiveness, and overall efficiency of the IGCC system.

The work for the project was divided into three phases:

Phase 1 -- Design and Permitting

Phase 2 -- Procurement, Construction, and Start-up

Phase 3 -- Operation and Data Collection

This PPA is mainly concerned with Phase 3 and only incidentally deals with Phases 1 and 2.

The Participant was responsible for providing or obtaining all services, licenses, permits, and agreements necessary to ensure the availability of operating and performance data and for providing or obtaining all facilities necessary for the design, fabrication, procurement, installation, construction, start-up, and operation of the IGCC system. The Participant was also responsible for developing a detailed study comparing hot and cold syngas cleanup systems for a Texaco-based IGCC system. However, because the hot gas cleanup system did not operate, it was not possible to conduct this study, and the statement of work made allowance for deleting this study in the event of technical failure of the hot gas cleanup system. The participant was also required to test five coals or coal blends during the first three years of operation.

III. Review of Technical and Environmental Performance

A. Technical Results

1. Fuel Analyses

Coal from eleven U.S. mines was gasified at Polk Power Station during the five year demonstration period. Six other fuels were gasified in combination with one another or in various blends with coal from one of the eleven mines. The fuels gasified and tonnages of each are identified in Table 1. Table 2 shows how long each fuel was fed, and fuel analyses are shown in Table 3. The main reason for testing so many fuels and fuel blends was to identify the fuel which resulted in the lowest cost of electricity. Another reason for changing coals was that two coals that performed well became unavailable due to mine closures. Some coals or blends simply bridged a gap created by temporary inventory shortfalls. Also, the DOE Cooperative Agreement included a requirement to test four coals. Regardless of the reason it was used, each fuel or blend provided new insights into IGCC operation and helped demonstrate fuel flexibility.

Evaluating a potential fuel includes quantifying its impact on processing cost. The cost impact of some fuel characteristics, such as sulfur and chlorine content, are relatively easy to determine. Although the effect of other factors, such as carbon conversion and gasifier refractory liner life, can be estimated from a chemical analysis, effects can only truly be determined by full scale operation, as successfully demonstrated in this project.

Table 1 Fuels Gasified During Tampa IGCC Project

Seam	Mine	Supplier	Tons Gasified
Individual Coals			
Pittsburgh No. 8	Humphrey	Consolidation Coal Company	85,743
Pittsburgh No. 8	Williams No. 4	Bell Mining Company, Inc.	19,800
Pittsburgh No. 8	Loveridge	Consolidation Coal Company	125,256
Pittsburgh No. 8	Cumberland	RAG Cumberland Resources, LP	170,058
Pittsburgh No. 8	Blacksville	Consolidation Coal Company	349,805
Illinois No. 6	Old Ben No. 11 Mine	AEI Resources, Inc.	63,467
Illinois No. 6	Wildcat	Sugar Camp Coal , LLC	10,620
West Kentucky No. 11	Ohio No. 11	Consol/Island Creek Coal Co.	563,436
Kentucky No. 9	Camp	Peabody Coal Sales , Inc.	589,835
Kentucky No. 9	Patriot	Peabody Coal Sales, Inc.	250,065
Indiana No. 5 and 6	Somerville	Black Beauty Coal Company	97,611
Blended Fuels			
Petroleum Coke	Chalmette	Oxbow Carbon/PCMC Petcoke	133,173
Indonesia	Paringin/Tutpan	P.T. Adaro Indonesia	72,433
Guasare Basin	Mina Norte	Peabody Coal Trade, Inc.	55,433
Pittsburgh No. 8	Powhatan No. 6	American Coal Company	30,593
Powder River Basin	Jacobs Ranch	Kerr McGee Coal Corporation	1,631
Biomass (Eucalyptus)	N/A	Common Purpose, Inc.	9

Table 2 Days of Operation on Individual Fuels

Coal/Mine	Days of Operation
Pittsburgh No. 8/Humphrey	190
Pittsburgh No. 8/Williams No. 4	9
Pittsburgh No. 8/Loveridge	26
Pittsburgh No. 8/Cumberland	86
Pittsburgh No. 8/Blacksville	35
Pittsburgh No. 8/Blacksville-Cumberland Blend	16
Pittsburgh No. 8/Powhatan No. 6 + 40% Guasare Basin/Mina Norte	20
Illinois No. 6/Old Ben No. 11	27
Illinois No. 6/Wildcat	6
Kentucky No. 9/Camp	229
Kentucky No. 9/Camp + 20% West Kentucky No. 11/Ohio No. 11	5
Kentucky No. 9/Patriot	100
Indiana No. 5 & 6/Somerville No. 7	28
West Kentucky No. 11/Ohio No. 11	247
West Kentucky No. 11/Ohio No. 11 Blended with:	
20% Powder River Basin/Jacobs Ranch	4
25% Indonesian/Paringen-Tutpan	44
20% Indonesian/Paringen-Tutpan	87
Petroleum Coke/Chalmette Blended with:	
60% Indiana No. 5 & 6/Somerville	6
Various Guasare Basin/Mina Norte + Indiana No. 5 & 6/Somerville	62
1% Biomass + Guasaare Basin/Mina Norte +Indiana No. 5 & 6/Somerville	1
60% Pittsburgh No. 8/Blacksville	10
40% Pittsburgh No. 8/Blacksville	10

Table 3 Analyses of Coals Gasified During Tampa IGCC Project

Seam/Mine	Ultimate Analysis, dry							Proximate Analysis, as received					
	Carbon	Hydro-gen	Nitro-gen	Sulfur	Oxygen	Ash	Chlor-ine	Higher Heating Value	Mois-ture	Volatile Matter	Fixed Carbon	Ash	Ash T250*
Pittsburgh No. 8													
Humphrey	76.52	4.90	1.58	1.87	5.91	9.14	0.08	13,060	5.87	35.41	50.12	8.60	2645
Williams No. 4	75.18	4.85	1.34	3.00	5.97	9.62	0.04	13,201	3.82	38.06	48.87	9.25	2205
Loveridge	77.82	5.15	1.51	1.90	5.88	7.63	0.11	13,670	2.11	37.10	53.32	7.47	2485
Cumberland	77.97	5.17	1.50	2.79	4.01	8.49	0.07	12,696	8.79	35.12	48.35	7.74	2372
Blacksville	81.14	4.83	1.42	1.93	3.50	7.10	0.08	13,667	4.03	30.38	58.78	6.81	2461
Powhatan No. 6	74.72	5.20	1.37	3.90	5.73	9.00	0.08	12,634	6.18	38.18	47.20	8.44	2238
Illinois No. 6													
Old Ben No. 11	70.27	4.84	1.36	3.72	9.10	10.60	0.11	10,934	13.70	34.62	42.53	9.15	2480
Wildcat	74.48	4.78	1.55	2.73	6.83	9.46	0.17	12,597	5.99	33.92	51.20	8.89	2420
West Kentucky No. 11													
Ohio No. 11	73.54	5.05	1.56	3.20	9.66	6.88	0.11	11,963	11.30	36.70	45.90	6.10	2265
Kentucky No. 9													
Camp	72.20	5.04	1.60	3.30	7.35	10.40	0.11	11,510	11.00	34.99	44.75	9.26	2415
Patriot	72.39	5.01	1.59	3.01	7.77	10.18	0.05	11,133	13.20	35.97	41.99	8.84	2391
Indiana No. 5 and 6													
Black Beauty	73.08	5.12	1.51	3.80	6.87	9.58	0.04	11,317	12.90	37.06	41.70	8.34	2279
Miscellaneous													
Indonesia/Paringin	72.64	4.97	0.86	0.13	20.20	1.21	0.02	9,363	25.90	36.43	36.77	0.90	2235
Powder River Basin/ Jacobs Ranch	69.69	5.03	0.96	0.29	18.30	5.71	0.05	8,847	26.70	33.21	35.90	4.19	2212
Petroleum Coke/ Chalmette Refinery	88.67	3.27	2.24	4.61	0.63	0.54	0.04	13,743	10.00	10.69	78.82	0.49	2253
Guasare Basin/Mina Norte	73.67	5.20	1.37	0.76	8.84	9.98	0.03	11,665	11.15	32.79	47.20	8.87	2820

* Temperature at which ash has a viscosity of 250 centipoise

2. *Clean Syngas Analysis*

The composition of clean syngas is given in Table 4. The data in the coal column are from seven coals operating with three different burners. There was relatively little variation in the syngas produced from the different coals. The data from petroleum coke blends are also quite consistent. Although the difference between the average composition of syngas from coal and from petroleum coke is statistically significant, the heating values are essentially the same. Thus, if petroleum coke is available at a lower price, it can be substituted for coal without affecting the heating value of the syngas.

Table 4 Syngas Composition

Analysis	Coal	Petroleum Coke Blends
	Average Value	
Composition		
H_2S + COS, ppmv	415	282
CH_4, ppmv	532	244
CO, vol%	44.06	48.29
CO_2, vol%	14.73	13.61
H_2, vol%	37.95	34.02
N_2, vol%	2.28	3.02
Ar, vol%	0.88	1.00
Total, vol%	100.00	100.00
Higher Heating Value, Btu/scf	263.2	264.0
Lower Heating Value, Btu/scf	244.3	247.0

3. *Slag Analysis*

Slag has two constituents: (1) coarse glassy frit containing relatively little carbon, and (2) smaller char particles containing most of the gasifier's unconverted carbon. Slag composition is shown in Table 5. When the fuel is coal, the analyses of the frit and char are relatively constant from coal-to-coal. As net carbon conversion changes with changes in fines recycle or operating temperature, the ratio of frit to char adjusts automatically. However, for petroleum coke, the compositions of the char and frit change with changes in overall conversion resulting from different settler bottoms recycle rates. In general, the practice is to recycle as much char as can be recovered so that the resulting frit will be suitable for applications such as cement manufacture.

Table 5 Slag Composition

Fuel	Kentucky No. 9 & 11		Pittsburgh No. 8		Petroleum Coke Blends		
	Average	Std. Dev. or Range	Average	Std. Dev. or Range	Average		
Recycle Conditions							
Recycle, % of Settler Bottoms	33	0-100	63	53-74	100	45	0
Recycle, % of Total Char Produced	22	0-64	48	42-54	72	33	0
Slag Constituents							
Frit in Net Slag, %	32	24-49	36	29-43	35.98	7.47	2.36
Frit Ultimate Analysis, wt%							
Carbon	2.82	0.29	4.23	0.21	2.22	13.50	34.47
Hydrogen	0.04	0.01	0.02	0.00	0.00	0.03	0.07
Nitrogen	0.04	0.01	0.05	0.00	0.02	0.13	0.35
Sulfur	0.20	0.06	0.16	0.01	0.07	0.41	1.02
Ash	96.90	0.36	95.54	0.23	97.68	85.93	64.09
Char Ultimate Analysis, wt%							
Carbon	37.60	0.22	43.87	0.40	71.87	77.09	84.19
Hydrogen	0.46	0.07	0.26	0.01	0.10	0.19	0.14
Nitrogen	0.48	0.06	0.51	0.01	0.67	0.75	0.86
Sulfur	2.94	0.67	1.81	0.04	2.40	2.35	2.62
Ash	58.52	0.78	53.55	0.36	24.96	19.62	12.19
Char Higher Heating Value, Btu/lb (dry basis)	5,451	72	6,253	57	10,464	11,310	12,374
Overall (Net) Slag, Average Values							
Slag (dry), lb/MWh (net)	81	--	78	--	58	121	195
Slag (dry), lb/lb fuel (dry)	0.109	--	0.116	--	0.085	0.169	0.256
Ultimate Analysis, %							
Carbon	26.13	1.15	29.51	3.94	46.81	72.34	83.02
Hydrogen	0.32	0.03	0.17	0.03	0.07	0.18	0.14
Nitrogen	0.33	0.03	0.34	0.04	0.44	0.70	0.85
Sulfur	2.02	0.40	1.21	0.20	1.56	2.21	2.58
Ash	71.19	0.84	68.76	4.21	51.13	24.57	13.41
Higher Heating Value, Btu/lb (dry basis)	3,587	149	3,990	625	6,585	10,573	12,193

a. Ash Mineral Analysis

The slag's ash mineral analysis almost exactly reflects that of the feed with the following exceptions.

- The chlorine in the fuel is converted to HCl in the gasifier and ends up in the process water instead of in the slag.
- The ultimate fate of a significant fraction of the mercury and smaller fractions of a few other volatile trace elements, such as arsenic, is not certain.
- Chromium from the gasifier's refractory liner is found in the frit. The chromium content of the frit is 100 to 1,500 ppm higher than that of the fuel's ash. Testing has verified that the chromium is not in the form of potentially hazardous Chromium VI.

b. Loss on Ignition

Loss on ignition (LOI) is a measure of the non-ash constituents of the slag (C, H, O, N, and S). A low LOI value is required for virtually all non-fuel end uses of slag, such as for cement and blasting grit. The glassy frit is generally suitable for such applications after most of the char is removed. On the other hand, the char has a high LOI value. High LOI makes the char more suitable for recycling to the gasifier. Table 5 shows the average ultimate analyses and heating value of slag from Kentucky and Pittsburgh seam coals and from petroleum coke blends.

c. Contaminants in Surface Moisture

If no special effort is made to dry or dewater the slag, it will retain approximately 30 wt percent surface moisture. In Polk's original configuration, this moisture consisted of grey or black water containing up to 3,500 ppm chloride and approximately an equal amount of ammonia. These make the frit unsuitable for end-use applications. The chloride is corrosive in end products, such as cement, and the ammonia content was high enough that odor was objectionable. Consequently, the plant was reconfigured so only stripped process condensate contacts the frit. Process condensate contains virtually no chloride, and stripping reduces its ammonia content to less than 500 ppm so the ammonia odor is barely detectable in the slag. This reduced the concentration of contaminates by over an order of magnitude, making the frit suitable for some end uses.

4. Sulfuric Acid

The sulfur removal system demonstrated the capability to meet the permitted SO_2 emission level of 357 lb/hr year round while processing fuels with sulfur content up to 3.5 wt percent or about 5.0 lb SO_2/million Btu. The sulfuric acid produced averaged 98.3 wt percent H_2SO_4 and 1.7 wt percent H_2O. Typical contaminants were 12 ppm iron and 20 ppm of substances reducing $KMnO_4$ (predominantly SO_2 and some NO_X dissolved in the acid). The acid is well suited for use in the local fertilizer industry. However, that market experiences periods of weakness, so equipment to produce an acid suitable for sale for water treatment is being commissioned. Those specifications require slightly weaker acid (93 percent) with lower SO_2.

5. Brine

The brine concentration system must maintain grey water chloride concentration at or below 3,500 ppm to prevent corrosion. The brine unit can process about 100 gal/min of grey water to remove 175 lb/hr of Cl. At full load (250 MWe net) and a normal heat rate of 9,600 Btu/kWh (HHV), this capacity limits Cl content of the fuel to about 0.075 lb/million Btu or about 0.10 wt percent at a coal HHV of 13,400 Btu/lb. The brine concentration unit was severely taxed when the plant was using coals from the Loveridge, Old Ben No. 11, and Ohio 11 Mines, which contain 0.11 percent Cl. Coal from the Wildcat Mine with 0.17 percent Cl exceeded the brine concentration system's capacity. The Cl concentration in the process water rose to 4,500 to 5,500 ppm. A larger brine concentration system would be required to process many U.S. coals, particularly those in the Illinois Basin that typically contain 0.2 wt percent Cl or more. When processing a blend containing about half petroleum coke, which has very little chloride, brine concentration system capacity is not a significant issue.

The brine concentration unit produces a salt with a typical analysis of 64.1 wt percent Cl and 32.4 wt percent NH_4 with 3.5 percent moisture. The salt normally leaves the process as a dry white solid cake, but sometimes with a grey tint due to minor contamination with coal fines from the process water. Even when it is snow white as it leaves the process, it tends to discolor as it absorbs moisture from the atmosphere. The chloride in the brine represents almost all of the chloride in the feed coal.

6. System Availability

Table 6 presents availability data for various portions of the Polk Power Station. In service means the percentage of total hours in the period that a system was in service. Availability refers to the percentage of the time that a system was either operating or on standby, ready to operate.

Table 6 Availability Data

Year	Gasifier in Service, % of Period	IGCC in Service, % of Period	Combined Cycle Availability, %
1996	27.5	17.2	47.8
1997	50.4	45.6	64.8
1998	63.3	60.8	88.7
1999	69.9	68.3	92.7
2000	80.1	78.0	88.7
2001	65.4	64.2	90.6

As can be seen, there is a steady gain in percentage of time the unit was in service from startup in 1996 through 2000, as initial equipment problems were solved, system improvements were made, and operating personnel became more familiar with the unit. A variety of factors led to a slight drop in performance in 2001, including a scheduled outage for gasifier refractor replacement and combustion turbine hardware inspection, failure of the ASU main air compressor, and an outage to deal with the problem of low carbon conversion.

Subsystem availability is shown in Table 7. Gasification showed the lowest availability of the three main plant sections, but an availability of 84 to 89 percent is very reasonable, considering all the failure modes that can result in a forced outage. Both the ASU and the power block showed somewhat lower availabilities than would be expected for these units, particularly the ASU, which should be proven technology. Table 8 shows additional gasifier statistics. From 1998 through the end of the project, the IGCC output factor and the gasifier utilization factor have been over 95 percent.

Table 7 Subsystem Availability

Unit	In Service, %	On Standby, %	Avail-ability, %	Planned Outage, %	Un-planned Outage, %	Unavail-ability, %	Total, %
October 1999 through September 2000							
ASU	80.5	13.4	93.9	1.1	5.0	6.1	100.0
Gasifier	77.8	10.9	88.6	5.8	5.6	11.4	100.0
Power Block	81.0	5.6	86.6	4.8	8.6	13.4	100.0
October 2000 through September 2001							
ASU	73.3	17.2	90.4	1.1	8.5	9.6	100.0
Gasifier	71.0	13.2	84.2	7.7	8.1	15.8	100.0
Power Block	81.4	12.5	93.9	3.1	3.0	6.1	100.0

Table 8 IGCC Output and Gasifier Utilization Data

Year	Gasifier In Service, hr	CombustionTurbine on Syngas, hr	Net Power from Syngas, MWh	IGCC Output Factor, %	Gasifier Utilization Factor, %
1996	1094	685	157,566	91.95	62.64
1997	4417	3997	897,701	89.83	90.49
1998	5548	5328	1,269,535	95.32	96.02
1999	6125	5987	1,415,757	94.58	97.76
2000	7033	6852	1,656,242	96.69	97.42
2001	5733	5623	1,285,470	91.45	98.08

7. Effect of Operating Variables on Results

The following sections discuss the effect of various operating variables on gasifier performance. Table 9 presents a typical energy balance for the Polk power plant; however, many factors, such as the nature of the fuel being gasified, performance of the slurry preparation system, fly ash recycle, etc., affect system behavior. Therefore, actual performance can vary from results shown in Table 9.

Table 9 Typical Energy Balance

Item	Energy Flow, million Btu/hr
In	
Coal Higher Heating Value	2,430
Out	
Slag and Fly ash	69
Cooling Water	248
Radiation and Unaccounted Losses	129
Steam Condenser	752
HRSG Stack	372
Net Power	860
Total Out	2,430
Efficiency, %	35.4

a. Slurry Preparation

Because every fuel performs differently in the slurry preparation system, full scale operation, together with experience, is needed to determine how to best prepare slurry from a particular fuel. Because Polk has a limited supply of oxygen, a high slurry concentration is essential to produce enough syngas for base load operation. Some fuels require an additive to lower viscosity so that high concentration slurries will flow through screens and pump suction piping. Other slurries require an additive to prevent fuel particles from settling in lines and agitated tanks. Slurries made from some fuels also require pH adjustment to minimize erosion/corrosion. Both a 50 percent caustic solution and anhydrous ammonia have been used to control pH (target value is about 8.0), but caustic is preferred.

b. Carbon Conversion and Gasifier Refractory Liner Life

High carbon conversion is important for efficiency and to minimize fly ash disposal costs. (Fly ash with high carbon content cannot be sold.) High conversion at high slurry concentration and low operating temperature would be ideal, since this would extend the gasifier refractory liner life and minimize the oxygen requirement. Minimizing oxygen consumption is particularly important at Polk, since the oxygen supply is limited. Fly ash containing unconverted carbon can be recycled to the gasifier to reduce its carbon content, but this increases the oxygen requirement, since it degrades the quality of the slurry fed to the gasifier. When the fresh feed is 100 percent coal, recycling fly ash appears to have only a slight positive impact on overall efficiency, since the energy recovered from the recycled fly ash is offset to a large extent by the incremental auxiliary power to produce the additional oxygen required. With petroleum coke in the fuel blend, the impact of recycle on overall efficiency is greater, since there is more recycled material and it has higher carbon content.

Although carbon conversion and refractory liner life for specific slurry can be estimated as a function of gasifier operating temperature, a full scale test is needed to determine these parameters at sufficient accuracy to develop the most cost-effective plant design. The Polk gasifier was the largest Texaco gasifier built as of the time it was constructed, so it was not possible to conduct such a test before designing the plant. This contributed to poorer per pass carbon conversion than expected and the consequent undersized oxygen plant.

At Polk, operating parameters are determined for the fuels being processed through an extensive sampling, analytical, and data reduction effort. Once steady-state plant operation is achieved, multiple samples of each important stream are gathered and analyzed over a 4 to 12 hr period, which is referred to as a heat and material balance period. The analytical results are then combined with other operating data (flows, temperatures, and pressures) using a nonlinear regression technique to determine the most likely values of the key variables.

Several data points are required to develop each fuel's "characteristic." This characteristic is best presented as a graph of carbon conversion versus indicated refractory liner life on which each point represents a different gasifier operating temperature or oxygen/carbon ratio. The characteristic curve for each fuel may shift with changes in any one of several independent variables, the most important of which are throughput, burner configuration, refractory liner quality or condition, slurry concentration, and fraction of fly ash recycled. The characteristic curves are used in an economic model to optimize plant operation, compare performance of different burner designs or refractory liners, compare fuels, or simply to alert that some unidentified change in a fuel property, such as ash composition, has occurred. Although there is some data scatter, the characteristic curves all show the trend of lower operating temperature associated with lower carbon conversion and longer liner life.

c. Effect of Refractory Liner Quality

The startup gasifier refractory liner was a low cost/low quality liner. Pittsburgh No. 8 coal from the Humphrey Mine was the closest available fuel to the design basis, so it was chosen as the startup fuel. Figure 8 compares data generated while the startup liner was in service to performance with the standard high quality liner in place. The design and expected operating points are also shown. The inferior performance (short life) of the startup liner is obvious. It is also clear that performance on the higher quality commercial liner with Pittsburgh coal was significantly below expected performance and somewhat below the design value.

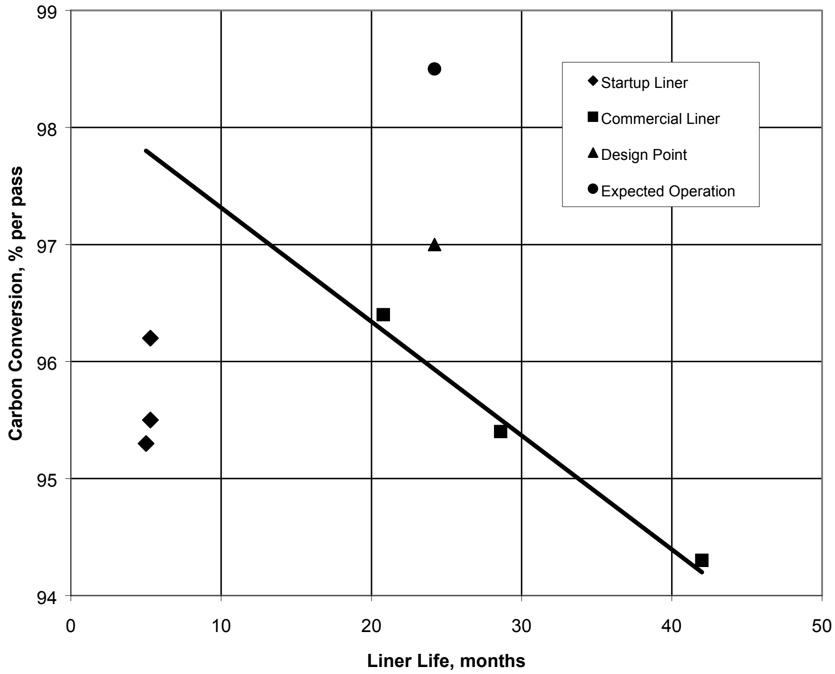

Figure 8 Gasifier Liner Life vs. Carbon Conversion

d. Effect of Burner Design

Because of the problem with low carbon conversion, Texaco cooperated in making several minor burner design modifications. However, these modifications did not have any statistically significant effect on gasifier performance. In early 1999, two radically different burner configurations were tested while processing a blend of West Kentucky No. 11 and Indonesian coals. However, neither design was better than the standard burner design. In mid-2001, a third test burner was installed during operation on a blend of 40 to 50 percent petroleum coke with Indiana No. 5 and 6 (Somerville Mine) and Guesare Basin (Mina Norte Mine) coals. Results with this burner were mixed, and a definitive conclusion concerning its benefit could not be reached.

e. Effect of Recycling Fly ash

Recycling fly ash increases overall carbon conversion and oxygen consumption. For West Kentucky No. 11 coal, recycle causes a significant drop in per-pass carbon conversion, which further increases the oxygen requirement. However, for a 40 to 55 percent petroleum coke blend with Indiana No. 5 and 6 (Somerville Mine) and Guesare Basin (Mina Norte Mine) coals, per-pass conversion improves with recycle, which partially mitigates the additional oxygen requirement. There seem to be several competing factors at work, such as changes in the oxygen/carbon ratio, slag volume, and reactivity of the recycled material. It is likely that the relative importance of these factors changes among fuels in a way that is not as yet fully understood. Thus, a test feeding the design coal is important in establishing a design basis for a new plant.

f. Results with Pittsburgh No. 8 Seam Coals

Five coals from the Pittsburgh No. 8 seam were processed (see Figure 9). Only the Humphrey Mine data were without recycle, with 30 to 75 percent of the settler bottoms fly ash being recycled to slurry preparation for the other coals. Humphrey Mine (the startup coal) and Loveridge Mine coals both performed reasonably well, within about 1 percent of design conversion at a two year liner life. For coals from the Bell, Blacksville, and Cumberland mines, carbon conversion was almost 4 percent lower than design when running at conditions that would produce a two year liner life. In general, results from Pittsburgh seam coal should fall somewhere in the area between the two trend lines shown on Figure 9.

g. Results with Illinois Basin Coal

Performance of Illinois Basin coal is shown in Figure 10. The data are all from operations with at least 30 percent fly ash recycle, but results without recycle were similar. All data points were with the standard burner, except for the Patriot Mine coal that used Test Burner No. 3, which may have contributed to its superior performance. Performance of the Old Ben No. 11 Mine coal was also excellent, but its high chloride content would require a larger brine concentration system. Coals from the Wildcat, Somerville, and Camp Mines all appear to be capable of a 95.5 to 96 percent per-pass carbon conversion with a two year liner life. West Kentucky No. 11 coal has a carbon conversion about 1 percent lower for the same liner life. Most coals from the Illinois Basin would be expected to fall somewhere in the area between the two trend lines on Figure 10.

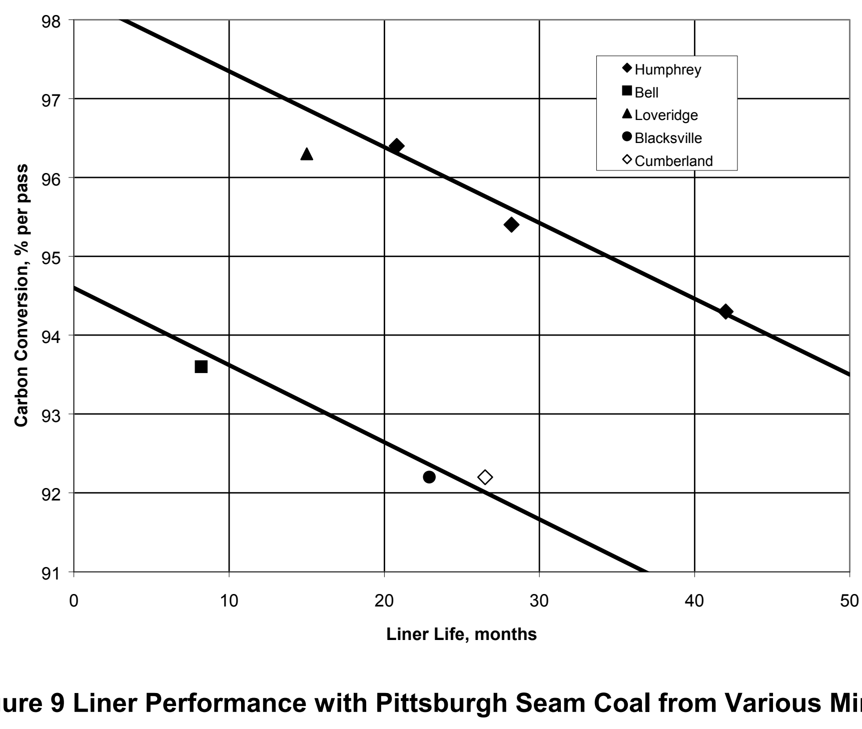

Figure 9 Liner Performance with Pittsburgh Seam Coal from Various Mines

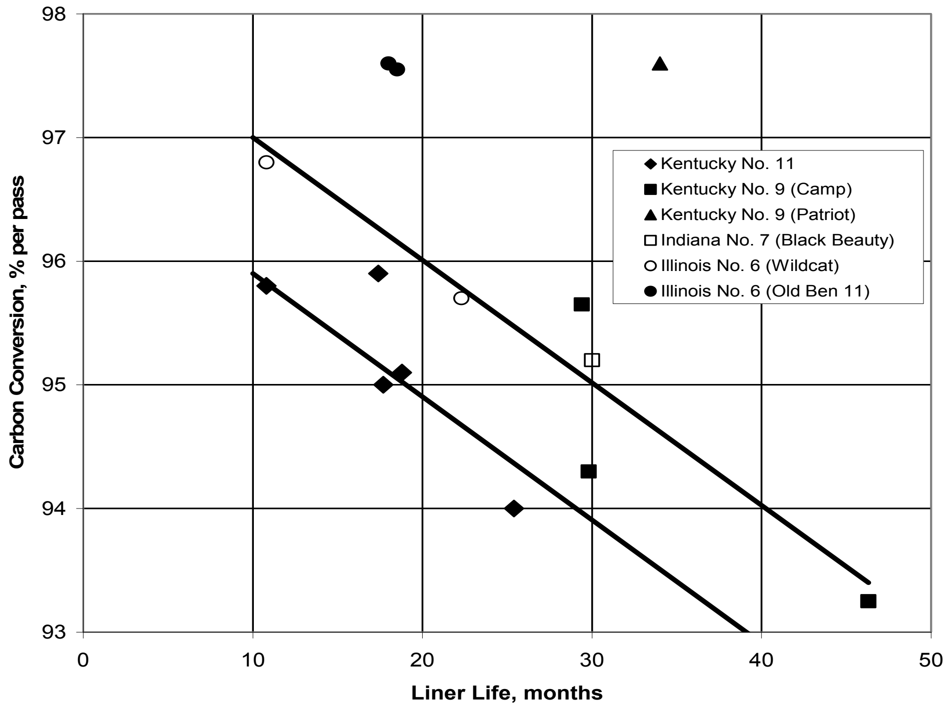

Figure 10 Liner Performance with Illinois Basin Coal from Various Mines

h. Results with Petroleum Coke Blends

Typically, petroleum coke is relatively inexpensive, on a dollars per Btu basis, compared to coal. However, petroleum coke usually has more sulfur than the Polk sulfur removal and recovery system were designed to handle (design basis was 3.5 percent sulfur), so it is necessary to blend petroleum coke with coal with a lower sulfur content. A further benefit of blending is that coal ash serves as a flux for vanadium in the petroleum coke. Vanadium oxide has a very high melting point and would form deposits under gasification conditions. Figure 11 shows results with petroleum coke blends. All data points were generated with at least 30 percent recycle of fly ash using the standard burner.

The first petroleum coke blends tested at Polk used specially selected shipments of Pittsburgh No. 8 coal from the Blacksville Mine. The first test series consisted of 40 percent coke and 60 percent coal with about 30 percent fly ash recycle. Conversion was about 84 percent for a 2-year liner life. The next test series consisted of 60 percent coke at 60 percent fly ash recycle. Operation at 84 to 86 percent per pass conversion on this blend resulted in a significantly longer indicated refractory liner life. It is not clear whether this performance improvement was due to the higher recycle ratio or the higher concentration of petroleum coke in the fuel blend.

In an effort to further improve performance, ash composition was tailored by blending a high ash fusion temperature coal from the Mina Norte Mine in South America with Black Beauty Indiana No. 7 Seam coal, which has a relatively low ash fusion temperature. This blend exhibited excellent liner life and acceptable conversion. Liner loss during normal operation should be quite low, with the major impact on actual life being due to startup, shutdown, and operational upsets.

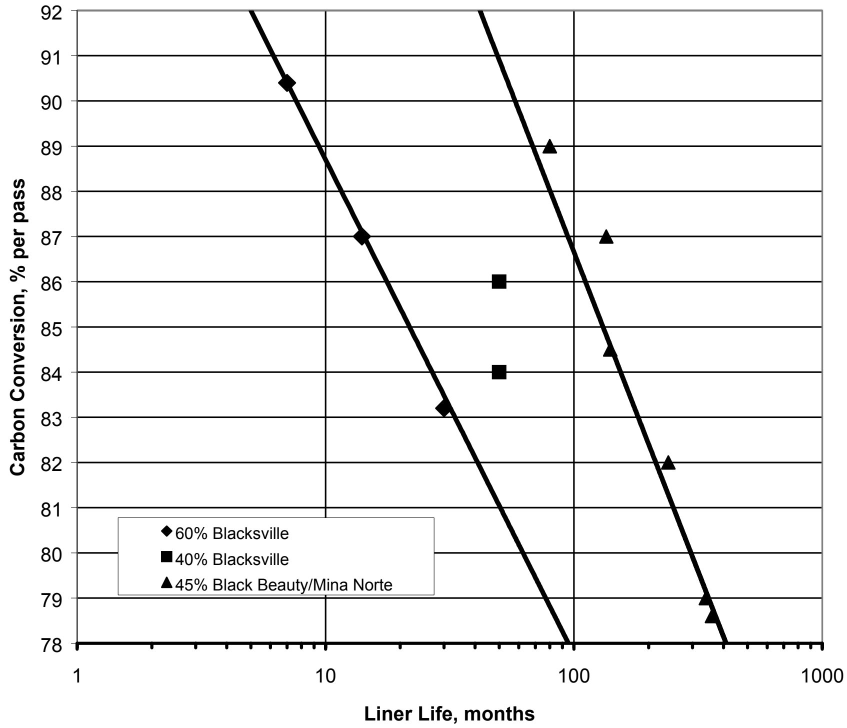

Figure 11 Liner Performance with Coal/Petroleum Coke Blends

B. Environmental Performance

This project demonstrated the performance benefits of an IGCC unit using gas cleanup technology for sulfur removal. The Tampa Electric facility achieved compliance with all federal and state regulatory requirements for air, water, and solid waste emissions. The highly efficient combined cycle generates electricity with significantly less air pollutant emissions and has lower water consumption and land use requirements than most other coal-fired power plants. A key advantage of IGCC is low SO_2 emissions, even when using lower-cost high-sulfur fuels, because sulfur at the point of removal is in the form of H_2S in the high-pressure syngas and is relatively easy to remove. In conventional coal-fired power plants, the sulfur is in the form of SO_2 at low concentration in ambient pressure stack gas, making it much more difficult to recover.

1. Air Emissions

a. Stack Emissions

Air emissions of SO_2, NO_X, and particulates, as well as volatile organic compounds (VOCs) and CO, were well below the required permit limits. Emissions from combustion of syngas in the turbine, primarily SO_2 and NO_X, vent to the atmosphere through the HRSG stack. H_2S in the syngas produced in the gasifier is converted to a salable by-product, sulfuric acid, which is marketed to the fertilizer industry. Permitted stack sulfur discharge limits and typical values from Polk's two stacks (HRSG and Sulfuric Acid Plant) are summarized in Table 10.

Polk's NO_X emissions (typically about 0.7 lb/MWh) are a fraction of those from conventional coal-fired power plants equipped with low-NOx combustion systems. These emissions were well within the permitted limit of 0.9 lb/MWh.

Table 10 Stack Emissions

Pollutant	HRSG Stack Emissions, lb/hr		Sulfuric Acid Plant Stack Emissions, lb/hr	
	Typical	Permitted	Typical	Permitted
SO_2	300	357	29	33
H_2SO_4	33	55	0.8	1.2

b. Particulate, VOC, and CO Emissions

Syngas volumetric flow is low relative to the volume of stack gas from a conventional plant, so intensive liquid scrubbing and filtration is economical. Particulate emissions, at 0.037 lb/MWh, are about 5 percent of those from conventional coal-fired power plants equipped with electrostatic precipitators. The permitted emission level is 17 lb/MWh.

2. Fugitive Emissions

Fugitive particulate emissions, generated principally by the coal and slag handling systems, are sufficiently controlled. To prevent emissions, transfer buildings and coal conveyors are enclosed, baghouse particulate control is employed at transfer points, coal piles are wetted, and wet grinding is used in rod mills. Good operational and management practices control gaseous fugitive emissions generated within the gasification plant.

3. Liquid Wastes

Storm water runoff is collected, treated, or recycled in accordance with applicable regulations. Plant systems are designed to maximize water recycling and reuse, thereby minimizing groundwater withdrawals and off-site discharges. The sulfuric acid plant consistently recovers over 99.5 percent of the sulfur it is fed, converting it to 98 percent sulfuric acid, which is sold. A small weak acid stream is neutralized and discharged to the cooling pond.

4. Solid Waste

The primary solid wastes produced by the gasification and syngas cleanup systems are slag and ammonium chloride salt. Slag produced by the process is a vitrified granular solid that is nonleachable and classified as non-hazardous by the EPA. Slag has commercial applications, such as a sandblasting material, an aggregate in concrete, a roofing material, industrial filler, in road construction, and as a building material. Ammonium chloride salt from the brine concentration system is sent to a landfill, but potential markets are being investigated.

IV. Market Review

A. Market Size/Commercialization

Figure 12 shows that the total worldwide syngas capacity in 2002 was about 43,000 megawatts (thermal) [Childress, 2002]. This includes gasification projects on all fuels (natural gas, coal, petroleum coke, and biomass) and producing all products (power, hydrogen, heat, and chemicals). Of the installed capacity, a little more than half is coal, or petroleum-coke-based. The figure shows that there has been a significant increase in gasification activity in the past decade with even more growth projected over the next few years. The majority of the recent increase in gasification capacity is fueled by coal or petroleum coke.

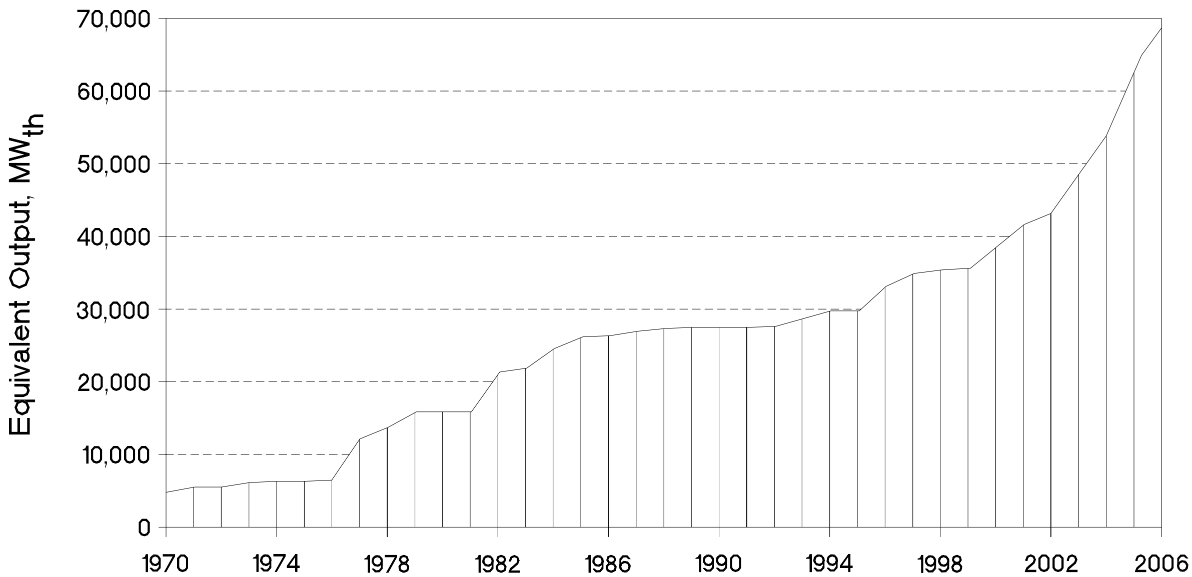

Figure 12 Cumulative World Synthesis Gas Capacity

The impetus for this growth is the increased costs for environmental compliance with conventional PC-fired units, the drive to improve efficiency, the availability of low-cost alternative feedstocks, and the need to utilize indigenous coal in areas without access to natural gas. The maturation of gasification technologies through completion of several large-scale demonstration projects has made this technology a popular and viable alternative to conventional combustion technology.

In addition to generating power, the IGCC concept can also be modified to produce value-added chemicals or transportation fuels from coal by chemical processing of the syngas produced, as opposed to using the gas to drive a combustion turbine. It's possible that the near-term market niche for IGCC lies not just in the production of electricity, but in the generation of multiple products, where electricity, steam, and chemicals are economically bundled as products from a fully integrated complex.

General Electric (GE) [Todd, 1998] has reported that there are about 5,000 MW of gasification projects for power generation that have proceeded to the point of placing orders for combustion turbines. Many of these projects include co-production facilities for production of hydrogen and/or chemicals. GE also stated that it is in discussions with various refiners, developers, and others about projects totaling another 50,000 MW. This indicates a significant market for gasification technology in the near future, bolstered by trends of rising energy prices and tightening environmental controls.

Indications are that many new domestic gasification projects will be refinery-based, utilizing petroleum coke and other low-cost refinery by-products to produce power, steam, hydrogen, and chemicals for the refinery and additional power for internal use or export. The TECO CCT project has developed data to permit evaluation of these applications through a petroleum coke test program at the Polk facility. Because of excellent environmental performance, the demonstrated technology should be well suited to refinery-based applications utilizing petroleum coke in areas that have been declared as non-compliant for one or more air emissions. TECO Power Services is in the process of commercializing IGCC technology as part of the Cooperative Agreement with DOE.

B. Economics

1. Capital Costs

The capital cost for each major section of the Polk Power Station IGCC is shown in Table 11. All project costs except interest during construction are included.

Table 11 Polk Unit 1 IGCC Capital Cost

AREA or ACTIVITY	Actual Cost, $1000	Escalated Cost To Mid-2001, $1000	Adjusted Escalated Cost, $1000	Adjusted Escalated Cost, $/kW
Air Separation	35,067	36,795	37,580	150
Gasification	129,810	136,281	121,799	487
Cold Gas Clean-up and Sulfur Recovery	31,517	33,064	37,000	148
Hot Gas Clean-Up	23,271	24,350	0	0
Power Generation	104,156	112,755	112,181	449
Plant Water Systems	24,504	25,505	26,303	105
Electrical In-Plant Distribution & Switchyard	29,028	30,282	30,282	121
Miscellaneous Common Utilities & Buildings	46,778	48,595	46,579	186
Subtotal Direct Costs	**424,130**	**447,628**	**411,724**	**1,647**
Site Acquisition and Development	65,391	70,256		
Construction Management, Startup, Operator Training, Warehouse Inventory	54,516	56,666	--	--
Project Development and Management, Permitting, and Preliminary Engineering	59,482	64,185	--	--
Miscellaneous Off-Site Cost: Big Bend Coal Truck Loading Facility	3,397	3,516	--	--
Total Project Cost	**606,916**	**642,251**	**--**	**--**
DOE Cost Share	(122,659)	--	--	--
Total Cost to Tampa Electric (Excluding Interest During Construction)	484,257	--	--	--

The first column of the table shows Polk's actual cost. The second column shows costs escalated from the year they were expended to mid-year 2001, based on escalation factors from the Chemical Engineering Plant Cost Index. The third column reflects Polk's best estimate of the cost of replicating the Polk design in a new plant incorporating all the lessons learned at Polk. The fourth column expresses these costs in $/kW, based on Polk's 250 MWe net output.

a. Capital Cost Adjustments

Over 90 adjustments were made to the original project scope to estimate the cost of replicating the Polk design in a new plant incorporating all the lessons learned. These adjustments, totaling $35.9 million ($144/kW), account for the difference between the second and third columns of Table 11. Only adjustments to the direct plant costs were addressed. In most cases, there will be significant savings in indirect costs as well, but these vary too widely between projects to make credible estimates possible. The most important changes from Polk Unit 1 are listed in Table 12.

The adjusted cost, at $1,650/kW (mid-2001 dollars), is relatively high, but is not surprising given site specific factors at Polk, most of which tend to increase costs. For example, the relative scarcity of water in Florida dictates that diluent nitrogen be used as the primary means of NO_X suppression rather than the more efficient and very much less expensive syngas saturation approach. The ability to discharge even a relatively small amount of process wastewater would obviate the need for the expensive brine concentration system. Also, Florida's high ambient temperature and relative humidity lead to higher cooling water temperatures and lower steam cycle output, further lowering efficiency and increasing the net cost per kW. In addition, Polk is a single-train unit with no economies of scale. Given the above factors, it is conceivable that a cost as low as $1,300/kW could be projected in a more favorable situation. This latter figure is used in the economic analysis that follows.

Table 12 Adjustments to Capital Costs for a New Plant Based on Lessons Learned

Item	Effect on Capital	Comment
Eliminate Hot Gas Cleanup	Save $25-30 million	Polk's hot gas cleanup system never operated and would not be included in a new plant. Significant savings accrue from eliminating the HGCU system and additional savings are realized by economies of scale with only one convective syngas cooler and syngas scrubber train instead of two.
Reduce Scope of High Temperature Gas Cooling	Save $10-15 million	The raw gas/clean gas exchangers were eliminated early in the project, and most of the sootblowing system has been removed. With these gone, the troublesome syngas cooler MP steam system can also be eliminated. In turn, these lead to significant cost reductions in the main gasifier structure.
Lower Direct Engineering Costs	Save $5-10 million	By replicating the Polk design and reducing the engineering requirements in the difficult high temperature gas cooling area, direct engineering cost reductions should accrue.
Add COS Hydrolysis and MDEA Reclaim	Add $3-4 million	COS hydrolysis and MDEA reclaim systems should be added.
Shorten Interconnecting Piping	Save $2 million	Polk Unit 1 is spread out, resulting in higher than usual interconnecting piping costs. Locating the main subsystems closer together would result in interconnecting piping cost reductions.
Add Slag Handling and Fines Separation Equipment	Add $2 million	Polk's original slag handling system had several drawbacks. It was manpower intensive, did not provide for separation of fines for recycle, and did not eliminate chloride and ammonia laden grey water from the coarse lockhopper slag, which would otherwise have been marketable. Also, the fines handling system was undersized for the much higher than

Item	Effect on Capital	Comment
		design fines production.
Add Syngas Saturator	Add $1.5 million	More diluent is needed than is available at Polk to meet future NO_X emission limits. A syngas saturator is a good way of providing this supplemental diluent while efficiently recovering the low level waste heat that became available when the raw gas/clean gas exchangers were removed.
Delete Water Wash Column	Save $1 million	Polk's original design incorporated a water wash column to remove contaminates which would form heat stable salts with MDEA. Extensive testing has shown that the water wash column is ineffective at removing these contaminates and that an ion exchange system to regenerate the heat stable salts is less expensive.
Increase Main Air Compressor Capacity	Add $500,000	A modest increase in the ASU's main air compressor capacity would provide sufficient oxygen year round to fully load the combustion turbine, even while recycling sufficient fines so that the slag would be marketable.
Upgrade Materials in Slurry Service	Add $500,000	Improved materials and coatings in the slurry preparation system would significantly reduce equipment failures.
Delete Fines Filter	Save $500,000	Off-site disposal of the fines produced by the Texaco gasifier is prohibitively expensive for Polk, and encumbering landfills with tons of material containing significant heating value is not appropriate. Recycling the fines as concentrated slurry from the settler bottoms to the slurry preparation system is Polk's current practice. This is a better alternative than producing a filter cake for disposal using the fines filter.
Modify Syngas Scrubber Design	Add $400,000	Polk's syngas scrubbers have a persistent problem with water entrainment when operating at design conditions. This has created some safety issues and other problems downstream. Modifications to eliminate this problem could require substantially increasing the size of the vessel.
Separate MDEA Acid Gas From Ammonia Gas	Add $400,000	Line plugging occurs wherever ammonia gas combines with acid gas. In a new plant, these streams should be completely separated.
Rust-Resistant Coatings for Main Air Compressor Components	Add $300,000	Most ASUs operate continuously, but in an IGCC plant they are likely to start and stop more frequently. This promotes the formation and exfoliation of rust particles from the carbon steel piping and main air compressor components. The rust particles plug the fins of intercoolers and after-coolers, destroying their effectiveness and increasing pressure drop. Coatings can eliminate this problem.
Other Changes	Add $4 million	Other changes individually cost relatively little. Some of these other adjustments are additions and some deletions, but their net effect is to add approximately $4 million to capital costs.
Total	Save $30-45 million	Total estimated reduction from the Polk Station facility costs.

2. Operating Costs

To take advantage of economies of scale, the following economic analysis is based on a plant size of 500 MWe (net). Also, to reduce coal price, the plant is assumed to be situated at a mine mouth. Operating costs are adjusted from values reported for Tampa's Polk Power Station.

a. Fuel

The highest annual cost element is fuel, and the vast majority of this cost is for coal/petroleum coke for the gasifier. At an energy requirement of 4,417 million Btu/hr and an 80 percent on-stream factor, the energy required is 30.95×10^{12} Btu/yr. At a cost of $\$1.00/10^6$ Btu, annual coal cost is $30.95 million. The only other fuel consumed during normal operation is 40 gal/day of propane (91,000 Btu/gal) for the flare pilot light. Since the flare is almost always lit, this requires 14,600 gal/yr.

Propane and distillate fuel are consumed during gasifier startup and after gasifier shutdown. The combustion turbine's startup and back-up fuel is low sulfur distillate. Minimum consumption would provide low load combustion turbine operation for one or two hours during gasifier light-off and line-out, and another one or two hours after gasifier shutdown. It would also typically be kept running during brief outages prior to gasifier hot restarts. The combustion turbines would consume about 100,000 lb of distillate per hour at low load operation or about 1,850 million Btu/hr. Assuming the combustion turbines operated on supplemental fuel 2 percent of the time, the cost of supplemental fuel for this purpose was estimated at $1,440,000/yr. (Although the combustion turbine may be operated on distillate fuel when the gasifier is unavailable, no allowance for long term operation of the combustion turbine on distillate is included in this analysis.)

The auxiliary boiler is also used to generate steam for regeneration of the ASU air dryers for extended operation, while it cools down before gasifier light-off and for operation to provide purge nitrogen for several hours following gasifier shutdown. An average of 87,500 lb (1,600 million Btu) is consumed during each gasifier cold startup and shutdown for an extended period.

Propane is used to heat the gasifier and sulfuric acid plant during cold startups, and a small amount is used to maintain sulfuric acid plant catalyst bed and decomposition furnace heat during brief outages prior to hot restarts. Normally, 2,000 gallons of propane (182 million Btu) is consumed during a hot restart and 16,000 gallons (1,450 million Btu) during a cold startup. The cost of all these uses is small compared to other costs and is estimated at $100,000/yr. Total fuel cost (coal plus supplemental fuel) is estimated to be $32.49 million/yr.

b. Labor

The Polk station is staffed by five operating and maintenance teams, each team consisting of ten multi-skilled process specialists who operate the unit and perform and supervise the maintenance work. Supporting the teams are a six-person engineering staff, nine specialists, a three person laboratory staff, and ten administrative and management personnel for a total of 78 people. It is estimated that a 500 MWe plant would require a team of 100 people. At an average rate of $40/hr for 2080 hr per person per year, labor costs are $8.32 million/yr.

c. Other Operating Costs

In addition to fuel and the salaries and fringe benefits for the permanent staff, the plant has historically incurred the annual costs shown in Table 13.

Table 13 Other Variable Annual Operating Costs

Item	Annual Cost, $ million
Catalysts and Chemicals -- Water Treatment, Flocculent, Acid Gas Removal, COS Hydrolysis and Sulfuric Acid Plant Catalyst	1.0
O&M -- General Maintenance and ASU: Building, Structure, and Site Maintenance; Safety and General Supplies; Waste Disposal (except slag)	1.5
O&M -- Gasification: Coal and Slurry, High Temperature Gas Cooling, Slag and Fines Handling, Gas Cleaning, Sulfuric Acid Plant	4.5
O&M -- Power Block, Common and Plant Water Systems	2.0
Sustaining Capital -- Small Projects: Replacement of Worn Capital Equipment and Minor Improvements	2.0

Slag handling and disposal costs are not included in Table 13. Costs for plant modifications, incremental fuel costs, and extra handling and waste disposal costs associated with the slag problem have totaled well over $10 million to date. Although these have been extremely burdensome, it is anticipated that all or most of them will be eliminated by some capital improvements within the next two years. It is assumed that the costs in Table 13 are proportional to plant size. Therefore, a cost of $22 million is used for a 500 MWe plant.

3. Estimated Cost of Electricity for a 500 MWe Plant

The basis for the economics for a 500 MWe IGCC power plant project, based on the Tampa Electric design, is given in Table 14. The cost of electricity using these parametric values is given in Table 15 on both a current-dollar and a constant-dollar basis. Capital cost is based on an estimated direct investment of $1,300/kW plus 20 percent for engineering, etc., or a total of $780 million.

Coal feed rate is 166.17 tons/hr, for a yearly cost of $30.95 million/yr at an 80 percent capacity factor. It was assumed that supplemental fuel was burned 2 percent of the on-stream time at a cost of $1.44 million/yr plus $0.1 million for minor supplemental fuel uses. Total fuel cost is $32.49 million/yr. Other variable operating costs are estimated to be $22 million/yr, based on the values in Table 13 for a 250 MWe plant. It is estimated that a staff of 100 people would be required at an annual cost of $8.32 million. Based on these values, the cost of electricity is about $0.059/kWh on a current dollars basis and $0.046/kWh on a constant dollars basis.

Table 14 Basis for Economic Evaluation

Economic Parameter	Value
Generating Capacity, MWe (net)	500
Plant Net Efficiency, % (HHV)	38.63
Plant Heat Rate, Btu/kWh (HHV)	8,833.6
Plant Capital Cost, $/kW	1,560
Capacity Factor, %	80
Coal Heating Value, Btu/lb (as received)	13,290
Coal Cost, $/million Btu (as received)	1.00
Labor Cost, $/hr (including burden)	40.00
Hours per man year	2080
Supplemental Fuel Cost, $/gal	0.75

Table 15 Economics* of Power Generation (500 MWe Plant)

Cost Factor	Base, $$10^6$	Current Dollars		Constant Dollars	
		Factor	mills/kWh	Factor	mills/kWh
Capital Charge	780.0	0.160	35.62	0.124	27.60
Fixed O&M Cost	8.32	1.314	3.12	1.000	2.37
Variable Operating Cost	54.49	1.314	20.43	1.000	15.55
Levelized Cost of Power			59.17		45.52

*Estimate based on information from Participant's final report

V. Conclusions

This project achieved its main goal of successfully designing, constructing and operating a 250 MWe IGCC system that is potentially capable of providing high performance, cost competitive, environmentally compliant electric power from coal. Since startup in September 1996, the plant has met its objective of generating low-cost electricity in a safe, reliable, and environmentally acceptable manner. On September 30, 2001, Polk Power Station completed its fifth year of commercial operation. The plant continues to operate base loaded as a key part of Tampa Electric Company's generation fleet.

The facility demonstrated its ability to operate on a wide variety of coals. However, coal properties, such as sulfur content, chlorine content, and ash level and composition, affect performance. Therefore, in designing a new plant, actual operating data on the design coal is crucial to avoiding problems, such as insufficient sulfur or chloride handling capacity.

The most significant problem encountered in this project was the lower than expected carbon conversion in the gasifier, which required recycling fly ash to the gasifier and increased oxygen requirements. Because of the effect of low carbon conversion on performance, the project did not quite meet its objective of demonstrating improved overall efficiency and cost effectiveness compared to conventional coal-fired power plants. Once the low carbon conversion problem is overcome, the improved efficiency will significantly advance this technology and demonstrate IGCC's superiority to conventional technology.

A missed opportunity resulted from the inability to operate the hot gas cleanup system due to the fact that the design sorbent did not demonstrate sufficient attrition resistance. Hot gas cleanup offers significant potential for improving the efficiency of IGCC. SO_2, NO_X, particulates, VOCs, and CO were all well below required permit limits. Thus, the project met the goal of demonstrating that IGCC should be the choice for coal-fired power plants because of significant reductions in pollutant emissions.

Approximately fifty-fifty blends of petroleum coke and coal work well. The low chlorine content of the coke allows use of high chlorine content coal, while lower sulfur coals can compensate for the typically high sulfur in the petroleum coke. In addition, the ash in the coal acts as a fluxing agent for the vanadium in the coke.

Overall, this was a successful project that demonstrated that an IGCC power plant can be successfully built and operated. It also provided much valuable information that will permit the design and operation of more efficient IGCC systems in the future.

Acronyms and Abbreviations

Ar	Argon
ASU	Air Separation Unit
BFW	boiler feedwater
Btu	British thermal unit
Btu/hr	British thermal unit per hour
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
Btu/scf	British thermal unit per standard cubic feet
Btu/yr	British thermal unit per year
CCT	clean coal technology
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
COS	carbonyl sulfide
DOE	U.S. Department of Energy
EPA	Environmental Protection Agency
gal/day	gallon per day
gal/yr	gallon per year
GE	General Electric
gpm	gallon per minute
H_2	hydrogen
H_2O	water
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HCl	hydrochloric acid
HHV	higher heating value
HP	high pressure
HP	horsepower
HRSG	heat recovery steam generator

IGCC	integrated gasification combined-cycle
IP	intermediate pressure
$KMnO_4$	Potassium permanganate
KVA	kilovolt-ampere
kW	kilowatt
kWh	kilowatt-hour
lb/hr	pound per hour
LOI	loss on ignition
LP	low pressure
MDEA	methyldiethanol amine
MWe	megawatt (electric)
N_2	nitrogen
NH_3	ammonia
NO_X	nitrogen oxides
O_2	oxygen
PPA	post-project assessment
psia	pound-force per square inch absolute
psig	pound-force per square inch gauge
RSC	radiant syngas cooler
scf/h	standard cubic foot per hour
SO_2	sulfur dioxide
SO_3	sulfur trioxide
TECO	Tampa Electric Company
TPS	TECO Power Services Corporation
TSA	temperature swing adsorption
VOC	volatile organic compound
wt	weight

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