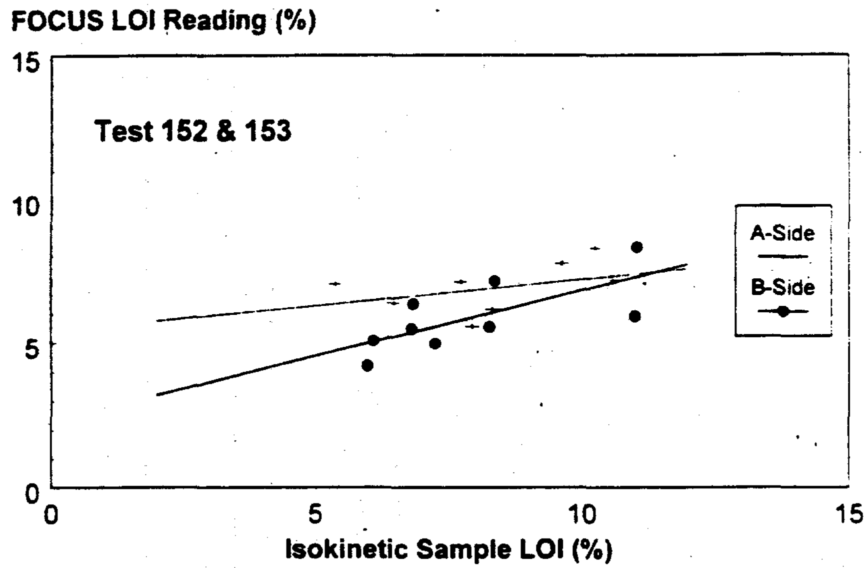

Figure 11. FOCUS versus Isokinetic LOI

As shown, all instruments provide minimal scatter around the line of best fit through the data, indicating adequate precision or repeatability of readings. In terms of accuracy, CAM and SEKAM provide best results, although the degree of accuracy was not always consistent. While the A-side and B-side curves for FOCUS readings deviated further from an ideal 45 degree prediction line (than CAM or SEKAM), the curves possess positive slopes. LOI values predicted using counts from the B-side camera appear to be more accurate than corresponding results from the A-side data.

Accuracy of CAM and SEKAM instruments was evaluated further by directly placing ash samples with known LOI into each unit's sample collection cell for analysis. An advantage of this procedure is the removal of concerns about collecting representative samples to compare with duct composites. In addition, it presented an opportunity to select ash sources which would intentionally provide a larger range of LOI values over which to evaluate accuracies. Figures 12 and 13 show CAM with a slight advantage in accuracy and consistency in these tests. Possible explanations for the differences in instrument and lab LOI include small amounts of moisture which could have been absorbed from the atmosphere during storage prior to use with the instruments. With either analyzer, it is expected that moisture would result in a higher reading.

Response Time

The time required for each unit to recognize a change in excess oxygen level was also considered in the evaluation. As mentioned earlier, the test series consisted of sampling at three loads and three oxygen levels at each load. To monitor the response of each instrument, the load and oxygen levels were plotted along with the LOI readings for each unit over a period of time. From Figure 14 it can be seen that, regardless of accuracy, the CAM and FOCUS units respond promptly to changes in boiler conditions. The SEKAM was much slower to respond due to its sampling procedure primarily as the result of the instrument requiring a relatively large ash sample to perform its analysis.

Equipment Problems

In addition to performance testing, a log was kept to reflect the availability of each unit and the problems encountered during operation. A summary for each unit is provided below.

SEKAM was installed in November 1994 and has reflected a high availability. Some of the problems that have been encountered and handled are listed as follows:

- Unit not providing readings; A/D converter card replaced.
- Sample valve cycled on and off; valve replaced.
- Extremely low LOI readings; instrument calibrated.
- Small leak in sample cell; valve seals replaced.
- Samples not collected; small holes in sample line patched.

CAM was installed in March 1995 and has demonstrated low to moderate availability, with noticeable improvement in the latter portion of the operating period. Some of the problems associated with this instrument included the following:

- Probe flanges too short; spacer inserted.
- Probes plugged; cleaned out probes.
- Unit shutoff due to a locked monitor; instrument restarted.
- Faulty heat tracing line; line replaced.
- Transmitter not working properly; transmitter replaced.
- Unit not responding during sample collection; weigh cell replaced.
- Moisture in plant air; additional filters installed.

FOCUS was installed in July 1995 and has shown a high level of availability. Maintenance items included:

- An East camera count error occurred due to slag screen movement. A lens filter was installed and the camera was repositioned.
- The automatic iris arrangement on the East side was also changed to a fixed aperture.

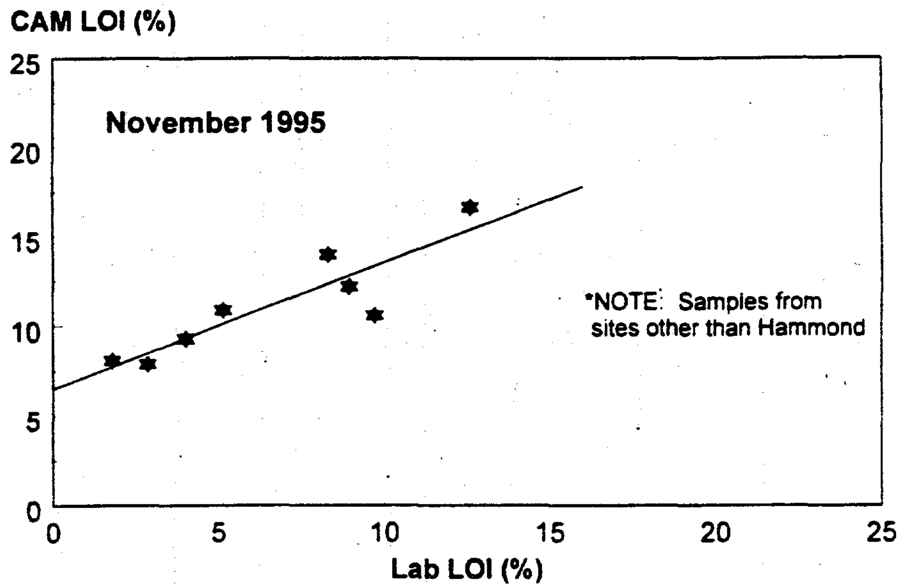

Figure 12. CAM Accuracy

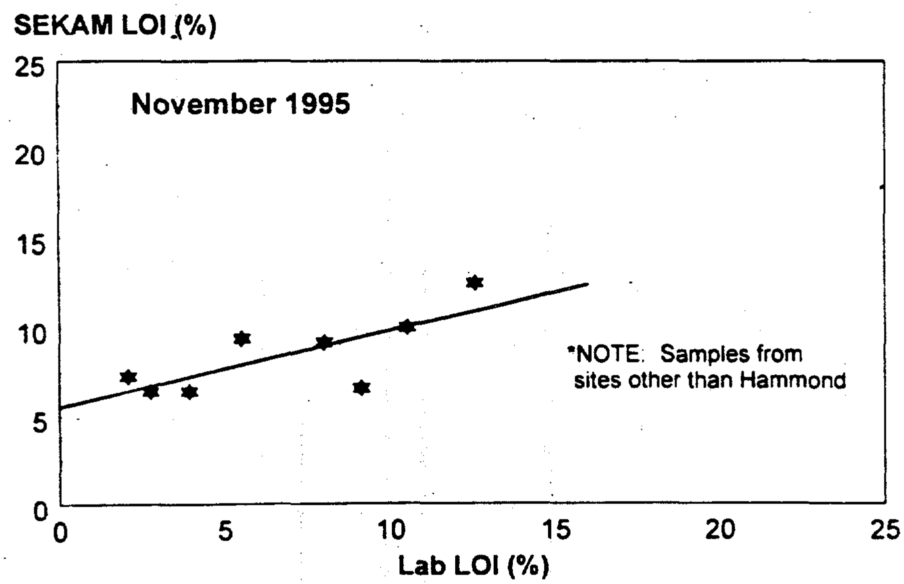

Figure 13. SEKAM Accuracy

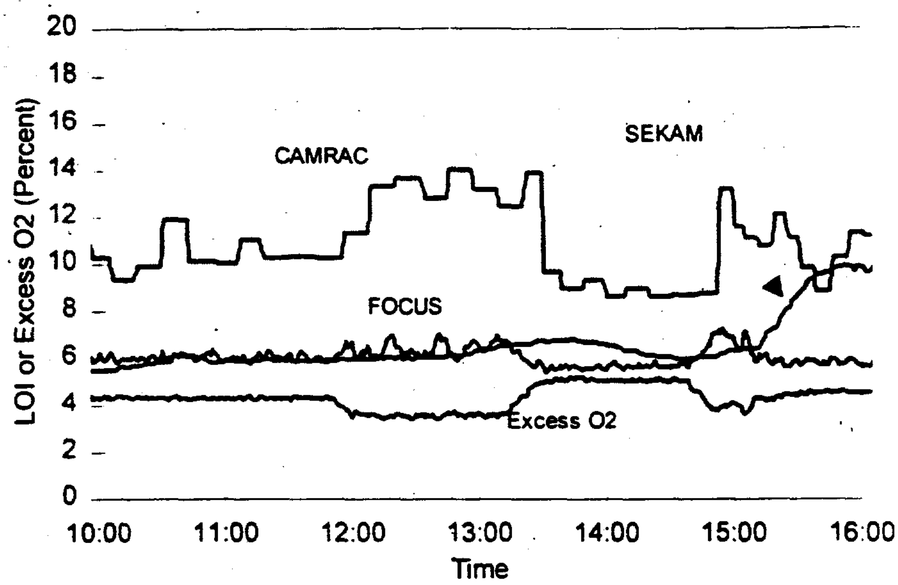

Figure 14. Analyzer Time Response

PHASE 4 - ADVANCED CONTROLS / OPTIMIZATION

Phase 4 of the project was the installation and demonstration of an advanced on-line optimization technology -- specifically, GNOCIS. GNOCIS (Generic NOx Control Intelligent System) is an enhancement to digital control systems (DCS) targeted at improving utility boiler efficiency and reducing emissions. GNOCIS is designed to operate on units burning gas, oil, or coal and is available for all combustion firing geometries. GNOCIS utilizes a neural-network model of the combustion characteristics of the boiler that reflects both short-term and longer-term trends in boiler characteristics. A constrained-nonlinear optimizing procedure is applied to identify the best set points for the plant. These recommended set points can be implemented automatically without operator intervention (closed-loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open-loop). The software is designed for continuous on-line use. The major elements of GNOCIS are shown in Figure 15.

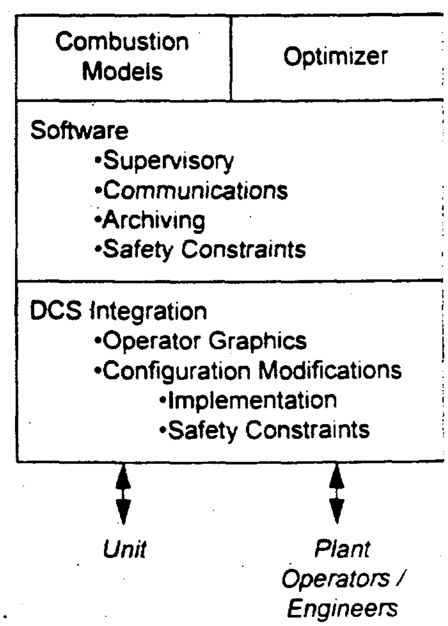

Figure 15. Major Elements of GNOCIS

Alabama Power Company's Gaston Unit 4, a 270 MW wall-fired unit, and PowerGen's Kingsnorth Unit 1, a 500 MW tangentially-fired unit served as developmental sites for GNOCIS [7].

GNOCIS development was funded by a consortium consisting of the Electric Power Research Institute, PowerGen, Southern

Company, Radian International, U.K. Department of Trade and Industry, and U.S. Department of Energy.

GNOCIS Implementation

From project inception, the goal of the GNOCIS installation at Hammond has been to implement a closed-loop, supervisory system. The Foxboro DCS, installed in 1994, included configuration enhancements which facilitated incorporation of GNOCIS into the overall control strategy. As at Gaston, all operator interaction with GNOCIS is through the DCS operator displays. The GNOCIS host platform at this site is a Sun Sparc 5 running the Solaris 2.3 operating system. This platform was chosen here since the Foxboro system also uses the Sparc architecture. The Sun interfaces to the DCS using local area network connection and TCP/IP.

Model Development

As at Gaston and Kingsnorth, data collected through the DCS are used to create the combustion models with modeling efforts concentrating on the most recent long-term data. As necessary, tests are run at off-design conditions to augment data available from normal operation and thereby expand the range over which the combustion model could make estimates.

Trial Results

Following the completion of installation, preliminary testing of GNOCIS at Hammond 4 began during February 1996 with tests being conducted at loads of 500 MW, 400 MW, and 300 MW. Various combinations of objectives were tested including minimizing NOx emissions, minimizing carbon-in-ash, and maximizing efficiency in both open- and closed-loop modes. Implementation of the GNOCIS recommendations were greatly facilitated as a result of enhancements made to the DCS. Results from these early tests suggested that further modifications be made to the system with the most important modification being the substitution of the overfire flow control damper positions for the corresponding overfire air flows. This change was necessary since these flow measurements had, to a large degree, become unreliable. On February 24, the unit went off-line for a scheduled maintenance outage.

During May 1996, testing of GNOCIS in both open- and closed-loop modes resumed with 22 tests being conducted. As before, various objectives were tested. Although relatively narrow limits were placed on the recommendations that GNOCIS could provide, preliminary analysis of the results are encouraging. On May 17, the unit came off-line as a result of turbine problems and has just recently returned to service. Several of the tests conducted prior to the outage are discussed below.

Test Day 158. Test 158 was conducted on May 7 with the unit off economic dispatch and at 480 MW. The purpose of the test was to evaluate the performance of GNOCIS in regards to boiler efficiency improvements as GNOCIS was made sequentially less constrained (Table 6). The tests were conducted in open-loop mode. Boiler efficiency and a subset of the independent control variables during the course of the test period are shown in Figure 16. As shown, nominal boiler efficiency was near 87.5 percent at the beginning of the testing and with sequential application of the GNOCIS recommendations, an efficiency of approximately 88.3 percent was attained. As can be seen in the figure, recommendations for excess oxygen, AOFA damper, and mill loading were implemented at approximately 11:15, 12:10, and 12:45, respectively. Also note that the recommended damper position is dependent on whether the mills are included in the optimization mix.

Test Day 161. Test 161 was conducted on May 15, 1996 at full load and in closed-loop mode. Results and control actions taken are shown in Figures 17 and 18 respectively. During the test day several objectives were tested including minimizing NOx and LOI and maximizing boiler efficiency. As with previous closed-loop tests at this site, recommendations were intentionally made narrow until further confidence was gained in the stability of GNOCIS recommendations (Table 6). When NOx minimization was the goal (Test 161-1), NOx emissions were reduced by approximately 10 percent from baseline. Similarly, when efficiency and LOI were goals (161-2 and 161-3), improvements of near 0.7 percent and 2 percent, respectively, were obtained. Also, in Test 161-2, simultaneous improvements in NOx, LOI, and efficiency were obtained. As can be seen in Figure 18, GNOCIS did not adversely affect the stability of the control actions.

Test Day 162. Test day 162 (Figures 19 and 20), conducted on May 16, 1996 was also at full load and GNOCIS was again operating in closed-loop mode. In Test 162-1, minimize LOI was the goal and as shown, a reduction of approximately 2.2 percent was obtained. As expected, NOx emissions increased with increasing O_2 levels. The goal was then changed to minimize NOx with O_2 clamped to the current levels. As shown, at least for the conditions present for this test, GNOCIS estimated that the other independent control variables (AOFA dampers and mill loadings) would have minimal impact on NOx emissions and therefore no control action was taken (Figure 20). The final test (162-3) freed up excess O_2 and the control action was taken resulting in a NOx reduction of approximately 10 percent. As with the prior days testing, there was no apparent adverse impact on the stability of the unit (Figure 20).

Table 6. Hammond / Short-Term Tests

Test	Goals			Limits		
	NO_x	LOI	Efficiency	Excess O_2	AOFA Dmpr.	Mill Flows
158-1	-	-	Max	±0.2	Clamped	Clamped
158-2	-	-	Max	±0.2	±5	Clamped
158-3	-	-	Max	±0.2	±5	±5
161-1	Min	-	-	±0.2	±5	±5
161-2	-	-	Max	±0.2	±5	±5
161-3	-	Min	-	±0.2	±5	±5
162-1	-	Min	-	±0.4	±5	±5
162-2	Min	-	-	Clamped	±5	±5
162-3	Min	-	-	±0.4	±5	±5

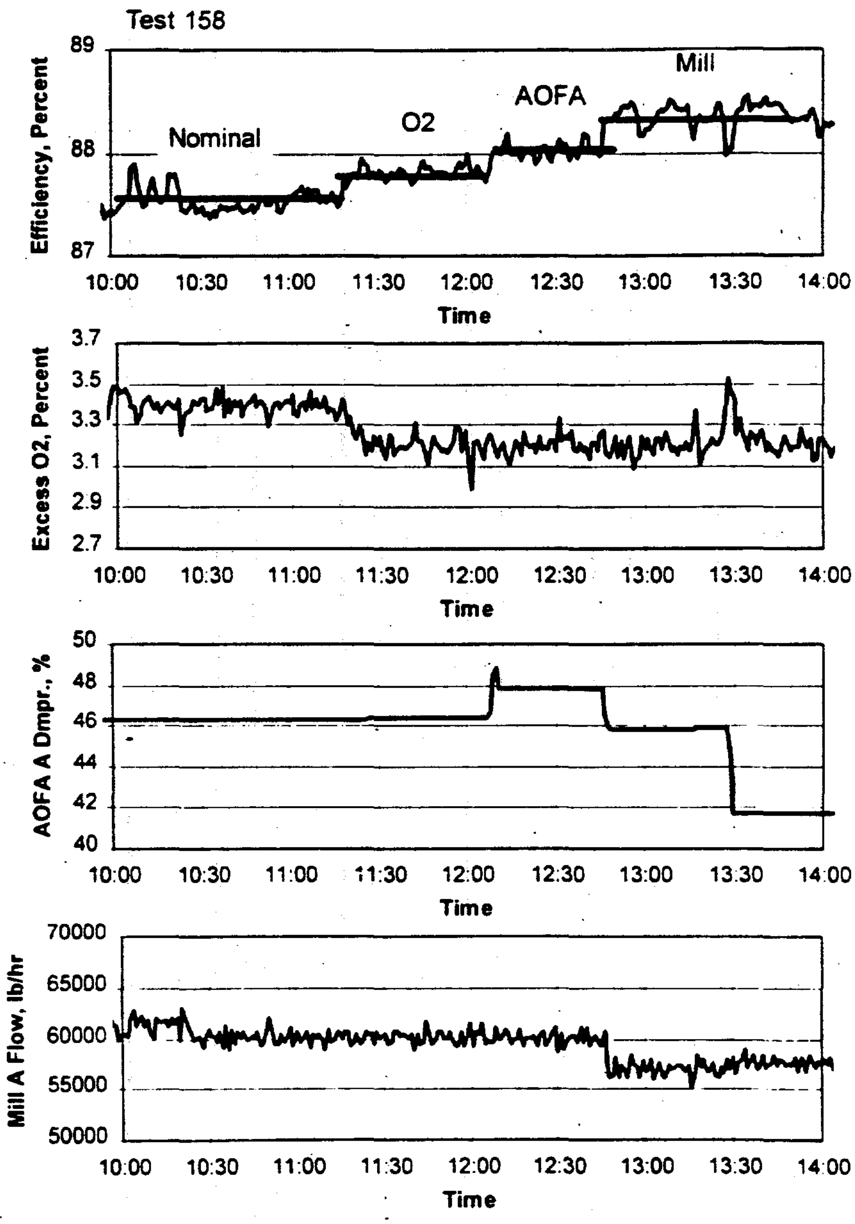

Figure 16. Hammond / Results of May 7, 1996 Testing

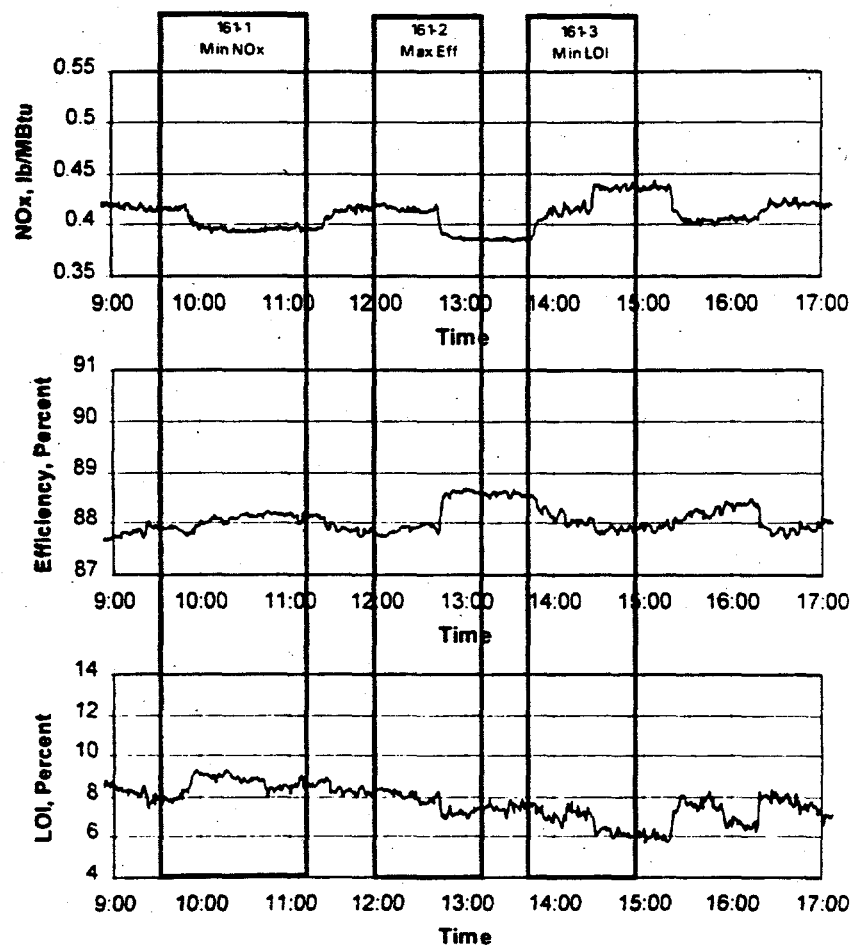

Figure 17. Hammond / Results of May 15, 1996 Testing

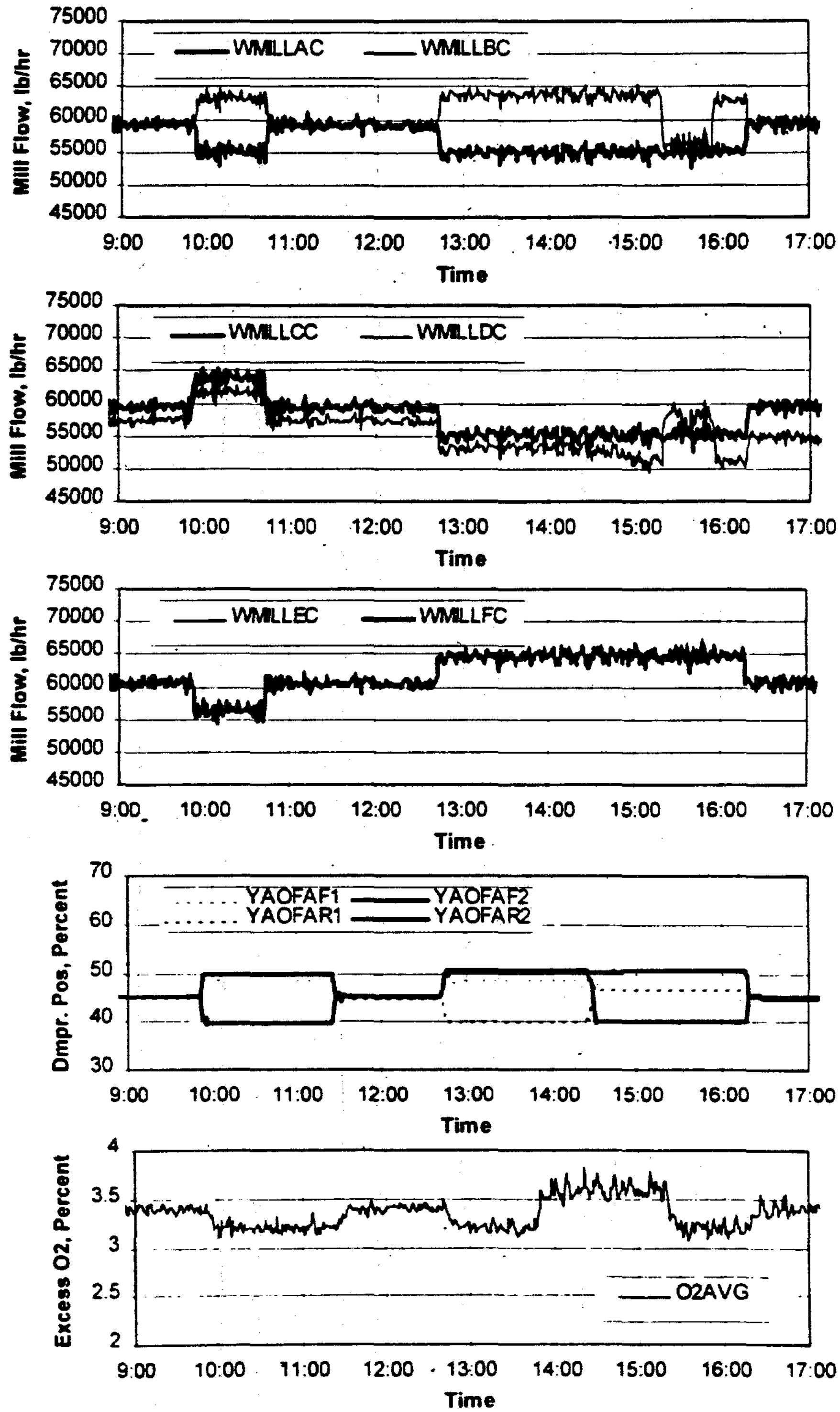

Figure 18. Hammond / Control Actions During May 15, 1996 Testing

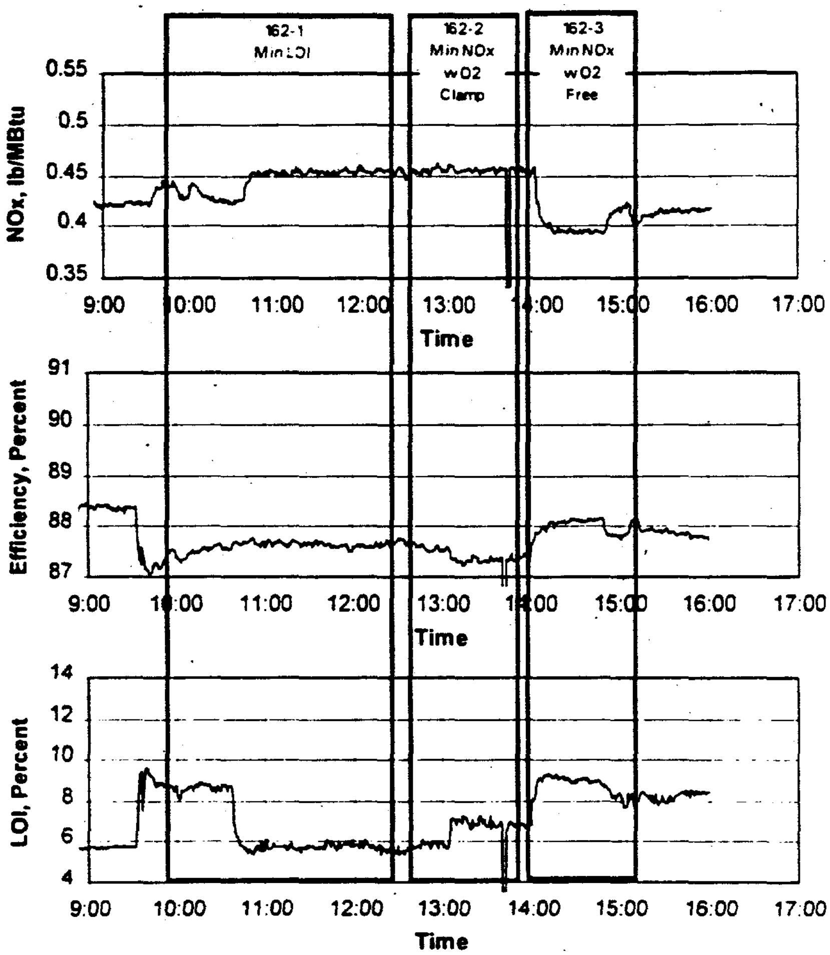

Figure 19. Hammond / Results of May 16, 1996 Testing

3. *500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide Emissions from Wall-Fired Boilers - Phase 3A Low NOx Burner Tests.* Southern Company Services, Birmingham, AL: 1994.

4 *500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide Emissions from Wall-Fired Boilers - Phase 3B Low NOx Burner plus Advanced Overfire Air Tests.* Southern Company Services, Birmingham. AL: 1995.

5. *500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NOx) Emissions from Coal Fired Boilers - Technical Progress Report - Third Quarter 1991.* Southern Company Services Inc.. Birmingham. AL: 1992.

6. Sorge, J.. Wilson, S., "500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NOx) Emissions from Coal Fired Boilers," Third Annual Clean Coal Technology Conference, September 6-8, 1994. Chicago, Illinois.

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Technical Session IV

Advanced Power Generation Systems

Wabash River Coal Gasification Repowering Project - First Year Operation Experience

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ABSTRACT

The Wabash River Coal Gasification Repowering Project (WRCGRP), a joint venture between Destec Energy, Inc. and PSI Energy, Inc., began commercial operation in November of 1995. The Project, selected by the United States Department of Energy (DOE) under the Clean Coal Program (Round IV) represents the largest operating coal gasification combined cycle plant in the world. This Demonstration Project has allowed PSI Energy to repower a 1950's vintage steam turbine and install a new syngas fired combustion turbine to provide 262 MW (net) of electricity in a clean, efficient manner in a commercial utility setting while utilizing locally mined high sulfur Indiana bituminous coal. In doing so, the Project is also demonstrating some novel technology while advancing the commercialization of integrated coal gasification combined cycle technology. This paper will discuss the first year operation experience of the Wabash Project, focusing on the progress towards achievement of the demonstration objectives.

Acknowledgements

DOE Project Manager: Gary Nelkin
Participant Joint Venture Manager: Phil Amick, Destec Energy, Inc.
Demonstration Period: December, 1995 - November, 1998

Research sponsored by the U.S. Department of Energy's Morgantown Energy Technology Center, under contract DE-FC21-92MC29310 with Wabash River Coal Gasification Repowering Project Joint Venture, 2500 CityWest Blvd., Suite 150, Houston, Texas 77042: telefax: (713) 735-4837.

Introduction

When the Wabash River Coal Gasification Repowering Project Joint Venture (the JV) *signed the* Cooperative Agreement with the U.S. Department of Energy (the DOE) in July 1992, this marked the beginning of a truly beneficial alignment amongst the entities involved. PSI needed a clean, low cost, energy efficient baseload capacity addition that would function as a substantial element of their plan to comply with the requirements of the Clean Air Act. Also important was this projects' ability to process locally-mined (Indiana) high sulfur coal. Finally, PSI needed a project that would pass the approval of the Indiana Utility Regulatory Commission as the low cost option for baseload capacity addition.

Encouraged by the data and experience gained at its Louisiana Gasification Technology, Inc. plant (LGTI) and by the DOE Clean Coal Technology Program, Destec was interested in advancing its gasification technology to the next generation to enhance the competitive position of gasification technology for future IGCC projects.

The DOE, through its Clean Coal Round IV Program, wanted a commercial demonstration of a clean coal technology to abate the barriers to commercialization of clean coal technologies and gain data to enable power generators to make informed decisions concerning utilization of clean coal technologies.

Through the Wabash River Coal Gasification Repowering Project (the Project), the needs of the participants and the DOE are being met with this 262 MW commercial power plant. This Project is demonstrating a clean, highly efficient technology that meets today's energy demand and tomorrow's (year 2000) clean air requirements.

Overview

The Project Participants, Destec Energy, Inc. (Destec) of Houston, Texas and PSI Energy, Inc., (PSI) of Plainfield, Indiana, formed the JV to participate in DOE's Clean Coal Technology (CCT) program to demonstrate the coal gasification repowering of an existing generating unit affected by the Clean Air Act. The Participants jointly developed, but separately designed, constructed, own, and are now operating an integrated coal gasification combined cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. Destec's gasification process is integrated with a new GE 7 FA combustion turbine generator and heat recovery stream generator in repowering of a 1950's - vintage steam turbine generator using pre-existing coal handling facilities, interconnects, and other auxiliaries.

The Project has completed the first year of a three year Demonstration Period under the DOE CCT program. The early operation of the Project, which is now the world's largest single-train coal gasification combined cycle plant operating commercially, has demonstrated the ability to run at full load capability while meeting the environmental requirements for sulfur and NO_x emissions. CINergy, PSI's post-merger organization, dispatches the Project second behind their hydro facilities on the basis of environmental emissions and efficiency, with a demonstrated heat rate of approximately 9,000 Btu/KWh (HHV).

Background

Destec Gasification Technology Evolution

Destec's parent Company, the Dow Chemical Company (Dow), began the development of the Destec Gasification process in the early 1970's. Dow wanted to diversify its fuel base from natural gas to lignite and coal for its power intensive chlor-alkali processes and began to develop the gasification process through basic R&D and pilot plants. Dow's first commercial gasification plant followed, the Louisiana Gasification Technology, Inc. (LGTI) facility in Plaquemine, La. This project operated from the second quarter 1987 until the third quarter 1995 under subsidy from the Synthetic Fuels Corporation and later the Treasury Department. When Destec was formed in 1989 the gasification technology was transferred from Dow to Destec.

Wabash Project Development

Destec approached PSI in early 1990 to initiate discussions concerning the DOE Clean Coal Technology Round IV program solicitation. Through the Wabash River Coal Gasification Repowering Project Joint Venture, the project submittal was made. In September 1991, the Project was among nine projects selected from 33 proposals. The Project was selected to demonstrate the integration of Destec's gasification process with a new GE 7FA combustion turbine generator and HRSG in the repowering of an aged steam turbine generator to achieve improved efficiency and reduced emissions.

Goals of Participants

- PSI wants to demonstrate an alternative technology for new units and repowering of existing units. Also PSI is incorporating this IGCC power plant into their system and wants to demonstrate this as a reliable and cost-effective element of their baseload generation capability.
- Destec is demonstrating the operability, cost effectiveness and economic viability of its gasification technology in a commercial utility setting.
- Destec wants to further enhance its gasification technology's competitive position by demonstrating new techniques and process enhancements as well as substantiate performance expectations and capital and operating costs.

- The DOE wants to abate the barriers to commercializing clean coal technologies, particularly gasification and repowering applications, and otherwise enable power generators to make informed commercial decisions concerning the utilization of clean coal technology.

Project Organization, Commercial Structure, and Costs

There are two major agreements which establish the basis of the Project. First, the Joint Venture Agreement was created between PSI and Destec to form the Wabash River Coal Gasification Repowering Project Joint Venture in order to administer the Project under the DOE Cooperative Agreement. Second, the Gasification Services Agreement (GSA) was developed between PSI and Destec and contains the commercial terms under which the Project was developed and is now operated.

PSI Responsibilities:
- build power generation facility to an agreed schedule
- own & operate the power generation facility
- furnish Destec with a site, coal, electric power, stormwater and wastewater facilities, and other utilities and services.

Destec Responsibilities:
- build gasification facility to agreed schedule
- own and operate the gasification facility
- guarantee operating performance of coal gasification facility including product & by-product quality
- deliver syngas and steam to the power generation facility

Project Costs

The overall combined cost of the gasification and power generation facilities was $417 million at completion. This cost includes the costs of engineering and environmental studies, equipment procurement, construction, pre-operations management (including operator training), and start-up. This figure includes escalation during the project. The start-up costs include the costs of construction and operations, excluding coal and power, up to the date of commercial operation in November 1995. Soft costs such as legal and financing fees and interest during construction are not included in this figure.

A savings of $30-40 million was realized by the repowering of the existing PSI facility, re-using the steam turbine and auxiliaries and coal handling equipment. This probably also reduced the project schedule by as much as a year, because of the simplified permitting effort versus a greenfield project.

Two areas of significant impact that increased the cost of the project were unanticipated construction problems and start-up delays. The construction effort was plagued by weather problems in the first nine months of the schedule, and later by labor shortages and construction contractor problems, that led to massive acceleration in the last 25% of the two year construction schedule. During the combined start-up of the gasification and power generation facilities, certain delays contributed to extension of the project fixed costs that also contributed to the final cost.

Project participants anticipate the costs of future units to be reduced dramatically, to the $1200/kw range for dual train facilities. Advances in turbine technology should bring the installed cost to under $1000 / kw for greenfield installations by the year 2000.

Project Schedule

The schedule for this project spans the time from selection in September, 1991 by the DOE during Clean Coal Round IV awards, to the end of the three year demonstration period in November 1998. The major project activities and corresponding milestones are as follows:

DOE Selection in Round IV	September	1991
Cooperative Agreement Finalized	August	1992
Environmental Assessment Complete	May	1993
State Air Permits Complete	May	1993
Indiana Utility Regulatory Approval Complete	May	1993
Began Construction	September	1993
Completed Construction	July	1995
First Coal Operation	August	1995
Began Commercial Operation	November	1995
Began Demonstration Period	December	1995
Complete Demonstration Period	November	1998
Final Report	February	1999

This aggressive schedule was possible by overlapping of activities between the development and engineering periods as well as the engineering and construction periods.

Review of Technology

General Design and Process Flow

The Destec coal gasification process features an oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier which uses natural gas for startup. Coal is milled with water in a rodmill to form a slurry. The slurry is combined with oxygen in mixer nozzles and injected into the first stage of the gasifier, which operates at 2600 F and 400 psig. Oxygen of 95% purity is supplied by a turnkey, 2060-ton/day low-pressure cryogenic distillation facility which Destec owns and operates.

In the first stage, coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas then flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value.

The syngas then flows to the High Temperature Heat Recovery Unit (the HTHRU), essentially a firetube steam generator, to produce high pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier where the carbon in the char is converted into syngas. Filter-element construction is a proprietary design proven at full scale at LGTI. The syngas is further cooled in a series of heat exchangers and passed through a catalyst which hydrolyzes carbonyl sulfide into hydrogen sulfide. Hydrogen sulfide is removed using MDEA-based stripper columns. The "sweet" syngas is then moisturized, preheated, and piped over to the power block.

The key elements of the power block are the General Electric MS 7001 FA high-temperature combustion turbine/generator, the heat recovery steam generator (the HRSG), and the repowered steam turbine.

The GE 7FA is a dual-fuel machine (syngas for operations and No. 2 fuel oil for startup) capable of a nominal 192MW when firing syngas, which is attributed to the increased mass flows associated with syngas. Steam injection is used for NOx control, but the steam flow requirement is minimal compared to conventional systems because the syngas is moisturized at the gasification facility, making use of low-level heat in the process. The water consumed in this process is continuously made up at the power block by water treatment systems which clarify and treat river water.

The HRSG for this project is a single-drum design capable of superheating 754,000 lb/hr of high-pressure steam at 1010 F, and 600,820 lb/hr of reheat steam at 1010 F when operating on design-basis syngas. The HRSG configuration was specifically optimized to utilize both the gas-turbine exhaust energy and the heat energy made available in the gasification process. The nature of the gasification process in combination with the need for strict temperature and pressure control of the steam turbine led to a great deal of creative integration between the HRSG and the gasification facility.

The repowered unit, originally installed in 1952, consisted of a conventional coal-fired boiler feeding a Westinghouse reheat steam turbine rated at 99MW but derated in recent years to 90MW for environmental dispatch. Repowering involved refurbishing the steam turbine to both extend its life and withstand the increased steam flows and pressures associated with the combined cycle operation.

The repowered steam turbine produces 104MW which combines with the combustion turbine generator's 192MW and the system's auxiliary load of approximately 34MW to yield 262MW (net) to the CINergy grid.

At the design point, the Air Separation Unit (ASU) provides oxygen and nitrogen for use in the gasification process but is not an integral part of the plant thermal balance. The ASU uses services such as cooling water and steam from the gasification facilities and is operated from the gasification plant control room.

The gasification facility produces two commercial byproducts during operation. Sulfur removed as 99.9 percent pure elemental sulfur is marketed to sulfur users. Slag will be sold as aggregate in asphalt roads and as structural fill in various types of construction applications.

Technical Advances

Using integrated coal gasification combined cycle technology to repower a 1950's-vintage coal-fired power generating unit essentially demonstrates a technical advance in and of itself.

More specifically, high energy efficiency and superior environmental performance while using high sulfur bituminous coal is the result of several improvements to Destec's gasification technology, including:

- Hot/Dry Particulate Removal, applied at full commercial scale with no provision for bypass.
- Syngas Recycle, which provides fuel and process flexibility while maintaining high efficiency.
- A High Pressure Boiler, which cools the hot, raw gas by producing steam at a pressure of 1,600 psia.
- A Dedicated Oxygen Plant, which produces 95% pure oxygen for use by the Project. Use of 95% purity increases overall efficiency of the Project by lowering the power required for production of oxygen.
- Integration of the Gasification Facility with the Heat Recovery Steam Generator to optimize both efficiency and operating costs.
- The Carbonyl Sulfide Hydrolysis system, which allows such a high percentage of sulfur removal.
- The Slag Fines Recycle system, which recovers carbon remaining in the slag byproduct stream and recycles it back for enhanced carbon conversion. This also results in a higher quality byproduct slag.
- Fuel Gas Moisturization, which uses low-level heat to reduce steam injection required for NO_x control.
- Sour water treatment and Tail Gas Recycling, which allow more complete recycling of combustible elements, thereby increasing efficiency and reducing waste water and air emissions.

The Project's superior energy efficiency is also attributable to the power generation facilities included in the Project. These facilities incorporate the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the steam turbine, including:

- The Project is the first application of Advanced Gas Turbine technology for syngas fuel, incorporating redesigned compressor and turbine stages, higher firing temperatures and higher pressure ratios, specially modified for syngas combustion.
- Repowering of the Existing Steam Turbine involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle is utilized.

Operations Experience

The Project completed the commissioning phase in August of 1995 and began the start-up process. By late August, the gasifier was ready for coal feed. The Project was in the start-up and testing mode through mid November at which time the start-up tests were complete and the Project was ready for the commercial operation and demonstration phase to begin. Significant in the start-up phase was the successful demonstration of the thermal integration of the combined operations. There were no substantial problems integrating the steam and water systems, although some early feedwater control problems contributed to early operation interruptions that carried over to the commercial operating period. These problems have since been resolved. The startup phase also demonstrated product (syngas) and by-product (slag & sulfur) quality and environmental performance.

Demonstration Period Test Plan

With this project being a full scale commercial unit in a utility environment, the Test Plan for the Demonstration Period focuses on successful operation of the plant as a base-load unit in the PSI system. Specifically, the goals of the participants for the Demonstration Test Plan primarily address continuous improvement in plant availability, operating and maintenance costs, maintaining dispatch, and improvement in overall performance while fulfilling the reporting requirements for environmental performance and equipment/system performance. Towards these goals, the next section will address the first year of performance under the three year demonstration period.

Operations Statistics/Milestones

The early commercial operation of the WRCGRP saw the plant build on the success of the start-up period with primary focus on attaining maximum sustained capacity for the purpose of final performance testing for the Air Separation Unit (ASU) Facility and Gasification Plant. The ASU Performance Testing was completed in February 1996 during an operating campaign that lasted over 300 hours. In March 1996 just four months into the operating period, the gasification plant demonstrated extended operation at 100% of rated design by running over 100 hours at or above gasifier design capacity. During these February and March operating campaigns the combustion turbine ran smoothly on syngas and had periods of operation at the 192 MW maximum rated capacity on syngas.

As the Project accumulated the early run time, evaluation of the technical advances noted previously showed that most of the new unit operations performed very well, however two of the areas contributed problems which affected run time. The primary problem area has been the reliability of the particulate removal system, primarily due to breakage of ceramic candle filters. Further testing and modifications to the particulate removal system are underway to minimize element breakage. Another problem area was chloride concentrations in both the COS hydrolysis catalyst beds and downstream heat exchangers in the syngas cooler line-up. Unexpected localized high chloride concentrations contributed to catalyst poisoning and chloride stress corrosion cracking in the low temperature syngas heat exchangers. A scrubber system has been installed to remove the chlorides from the syngas prior to the COS hydrolysis beds and syngas heat exchangers. These modifications are in place as the plant moves into the second operating year.

On the Power Block side the new Advanced Gas Turbine has performed very well on syngas. The turbine's operation has been more stable on syngas than on oil, with blade temperatures more evenly distributed and less temperature spiking. NO_x is controlled with steam injection to meet air permit requirements. The turbine experienced three problem areas after the acceptance of syngas. The first was in the syngas module and the piping from the module to the gas turbine. Expansion bellows required redesign and replacement to eliminate mechanical cracking in the flow sleeves. This problem was corrected by GE efforts in early syngas runs. The second problem has been the syngas purge control. These problems were primarily related to field devices such as solenoid valves and flow measuring devices. The solenoids have been redesigned and replaced and GE continues to work on flow measuring devices. The third area was the GE required row 2-3 spacer modifications, a fleet problem unrelated to syngas utilization.

Table I shows the production statistics for both the Gasification plant and combined cycle plant through October 1996.

Gasification Plant Production Statistics	
First Coal Gasified	August 17, 1995
Total Gasifier Hours on Coal*	2035
Total Syngas produced*	2,814,066 MMBtu (Dry)
Total Coal Processed*	189,233 Tons
Highest Capacity Demonstrated (% Nameplate)	103% (1825 MMBtu/hr, HHV)
Longest Continuous Coal Run* (Hours)	253
Cold Gas Efficiency (%)	>74%

Combined Cycle Plant Production Statistics	
First Syngas to Combustion Turbine (C.T.)	October 3, 1995
Total C.T. Hours*	2872
Total C.T. Hours on Syngas*	1340
MWH'S produced on Syngas*	333,486
Highest C.T. Capacity Demonstrated (% Nameplate)	100% (192 MW)
Longest Continuous Syngas Operation* (Hours)	151

*(All Production Statistics through October 1996)

TABLE I

Following is an operations summary of each major operating area, including the areas mentioned above, with a discussion of the process modifications incorporated to address the early problems encountered.

Area Operations Summaries

Coal Slurry Preparation

Coal is ground into a slurry in a rodmill, using recycled water from the gasification process. Wet milling reduces potential fugitive particulate emissions and minimizes water consumption and effluent waste water volume. The slurry is stored in an agitated tank large enough to supply the gasifier during rodmill forced outages.

The slurry preparation area has now processed (189,233) tons of coal with no significant problems. Typical problems handling coal during low ambient temperature conditions and heavy snowfall were experienced, primarily with the automatic sampling equipment, but the slurry has consistently met target solids concentration. The slurry storage and feed systems have also performed very well since the beginning. Typical Coal properties are shown in Table II.

COAL PROPERTIES	
Moisture	5-15%
Ash	5-15%
Sulfur (dry)	2.3 - 5.9%
Ash fusion temperature	2000-2500 F
Heating Value (MAF)	Over 13,500 Btu/lb (HHV)

TABLE II

Oxygen/Nitrogen Generation and Supply

The Air Separation Unit (ASU), supplied by Liquid Air Engineering Co. (LAEC), produces 2060 t/d oxygen at 95% purity as well as high purity nitrogen and dry process air for use in the gasification process. The process involves air compression, purification, cryogenic distillation, oxygen compression, and a nitrogen storage and handling system. After modifications to improve nitrogen production the ASU has reliably supplied products to the gasifier island at specified quantities and quality.

Gasification and Slag Handling

The two stage Destec gasifier operates with a slagging first stage and an entrained flow second stage. Coal slurry and oxygen are fed to the first stage as well as recycled char from the particulate removal system. This stage operates at 2600 F, producing syngas which exits to the second stage. Molten slag exits the first stage through a taphole and is quenched in a water bath prior to removal through Destec's continuous slag removal system. The second stage of the gasifier uses additional coal slurry and recycled syngas to lower the temperature to 1900 F. Raw syngas exits the gasifier enroute to the syngas cooler.

The gasification and slag handling areas have performed very well thus far. Slag removal has been essentially trouble free since the beginning. The gasifier has consistently processed the coal into high quality syngas.

Syngas Cooling, Particulate Removal, and COS Hydrolysis

Syngas containing entrained particulates exit the gasifier and is cooled in a firetube heat recovery boiler system, producing 1600 psig saturated steam. Cooled raw gas leaving the boiler passes through a barrier filter unit to remove particulates (char) for recycle to the first stage of the gasifier. The particulate free gas is further cooled prior to entering the COS hydrolysis unit where COS in the raw gas is converted to H_2S for removal in the Acid Gas Removal system. This area of the gasification plant has experienced problems which can be summarized into three areas: (1) Ash accumulation at the inlet to the firetube boiler, (2) particulate breakthrough from the barrier filter system, and (3) poisoning of the COS catalyst due to chlorides and trace amounts of arsenic in the syngas.

Ash deposition has not been a major contributor to overall downtime, but has limited runtime somewhat due to ash accumulation at the inlet to the boiler tubes. Improvements have been incorporated to reduce and manage this ash, and more improvements are planned.

Particulate breakthrough has been primarily due to movement and breakage of the ceramic candle filter elements. Substantial downtime is associated with entry into the particulate filter vessels, therefore there has been significant emphasis on improvements to this system. These improvements will be implemented during the third quarter and fourth quarter of 1996.

Poisoning of the COS catalyst due to chlorides and trace arsenic led to early replacement of the catalyst. To address this concern as well as metallurgy concerns with chlorides further downstream in the process, a scrubber system has been installed. The scrubber has satisfactorily resolved these problems.

Low Temperature Heat Recovery and Syngas Moisturization

After exiting the COS hydrolysis unit, low level heat is removed from the syngas in a series of shell-and-tube heat exchangers prior to Acid Gas Removal. This low level heat is used for syngas moisturization, stripping of the acid gases in the Acid Gas Removal system, and preheating condensate. This section of the process has performed well in terms of providing the moisturization for the syngas and providing heat transfer as designed. However, localized chloride stress corrosion cracking to some of these exchangers necessitated replacement with alternate metallurgy. The scrubber mentioned earlier in addition to protecting the COS catalyst, has eliminated metallurgy concerns in this section of the process.

Acid Gas Removal and Sulfur Recovery

The Acid Gas Removal system consists primarily of an H_2S absorber column and an H_2S stripper column. H_2S is removed from the syngas in the absorber using a solvent (MDEA) and the syngas is then routed to the moisturizer column mentioned previously. The H_2S absorbed is stripped and routed to the Claus process where it is converted to elemental sulfur. The remaining small amount of unconverted H_2S in the acid gas is compressed for recycle to the gasifier. During process upsets, the spent acid gas is sent to an incinerator, which is one of the permitted air emissions sources. The Acid Gas Removal process has effectively demonstrated removal of over 99% of the sulfur in the syngas. The typical product syngas composition from the plant is shown in Table III.

TYPICAL PRODUCT SYNGAS COMPOSITION	
Component	**Volume Percent**
Hydrogen (H_2)	28
Carbon Monoxide (CO)	38
Carbon Dioxide (CO_2)	10
Methane (CH_4)	1
Nitrogen (N_2)	1
Water (H_2O)	22
Sulfur Compounds	<50 ppmV
Heating Value (dry)	285 Btu/scf (HHV)

TABLE III

Environmental Performance

Total sulfur dioxide emissions from the three permitted emissions points (HRSG stack, gasification flare stack, and tail gas incinerator stack) have demonstrated the ability of the gasification process to successfully operate below 0.2 lbs/MMBtu of coal input. To date, emission rates of less than 0.1 lbs/MMBtu have been attained. This represents a 94% reduction in SO_2 emissions from the decommissioned Unit 1 boiler at Wabash River. The 0.2 lbs/MMBtu is significantly below Acid Rain limits for the year 2000, which are set at 1.2 lbs/MMBtu under the Clean Air Act.

Sour Water Treatment

Sour water is condensed from the syngas in the low temperature heat recovery section of the gasification plant. This water is primarily used for recycle to the slurry preparation plant. The recycled water is stripped of all dissolved gases except ammonia, which remains in the recycled water. Excess water is stripped of all dissolved gases and discharged through a permitted outfall. The sour water treatment system has performed well.

Combustion Turbine

The combustion turbine has operated in excess of (2800) fired hours on syngas and No 2 fuel oil. The turbine has operated in the designed baseload configuration and as a liquid fuel fired combined cycle peak service generator. Both modes of operation have proven to be stable and viable options for the operation of the generator on the bulk power system. The combustion turbine control system (Mark V) has proven, after initial startup tuning, to be reliable and maintainable by on-site PSI technicians. This system does require formal training for the technicians to develop the necessary skills for long term maintenance. Technicians were trained to maintain Gas Turbine Controls (Mark V), the excitation system (EX2000) and the Gas Turbine cranking system, (LCI). On site control maintenance capability is critical to establishing an available and reliable Gas Turbine.

Steam Turbine

The steam turbine is an early 1950's vintage Westinghouse reheat turbine. The original nameplate for the steam turbine was 99MW, but the repowered rating is 104MW due to the removal of the steam extractions. Throttle pressure has been maintained at the original 1450 psig and throttle temperature is 1005 F. The steam turbine and turbine auxiliaries are located approximately 1600 feet from the gas turbine power block and consequently required extensive piping and drains installations. Although the steam turbine is remotely located with respect to the new power block, the steam turbine operation interface is in the new control room with the new power block controls, Westinghouse WDPF.

Additional modifications were required to the repowered steam turbine as follows. The condensate and feedwater heating extractions were removed and capped. The cold reheat extraction was inspected and maintained for the repowered operation. One row of blading was replaced in the low pressure turbine as a result of the repowering. The generator was rewound and the generator rotor was replaced. A new static excitation system was installed to improve the reliability. The hydraulic turbine controls were replaced with the Westinghouse DEH control system. Existing Turbine Supervisory Instrumentation (TSI) was left in place and remains functional.

The turbine experienced a control shaft failure during the early operation due to an improperly sized cold reheat orifice causing the rotor to thrust, resulting in the failure. Otherwise, the steam turbine has operated very well in the new configuration.

Water Treatment

Water treatment was designed to meet the needs of both the power block and the gasification island. Surface water is drawn from the Wabash River and clarified with a CBI Claricone, filtered then metered to various demands at both operating blocks of the project. Some filtered water is treated in two parallel 480 gpm demineralizers. There is 750,000 gallons of demineralized water storage capability. This water is the supply for the steam cycles of the power block and the gasification island. The control of the water facility is also included in the scope of the Westinghouse WDPF system and can be operated from the central control room. Operation of the water facility has been reliable and cost effective.

OUTLOOK/SUMMARY

Through the first year of the demonstration period, the Wabash River Coal Gasification Repowering Project has made good strides towards achieving the Project Goals. Both the Gasification and Combined Cycle Plants have demonstrated the ability to run at capacity and within environmental compliance while using locally mined coal. The technology advancements which made this a DOE demonstration project have, for the most part, operated well. Modifications were made to address those problem areas identified through the early operation experience, modifications which have improved plant operation and will further allow demonstration of the Project Goals as the project moves into the second year of the demonstration period.

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Tampa Electric Company
Polk Power Station IGCC Project
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ABSTRACT

The Tampa Electric Company Polk Power Station is a nominal 250 MW (net) Integrated Gasification Combined Cycle (IGCC) power plant located to the southeast of Tampa, Florida in Polk County, Florida. This project is being partially funded under the Department of Energy's Clean Coal Technology Program pursuant to a Round III award. The Polk Power Station uses oxygen-blown, entrained-flow IGCC technology licensed from Texaco Development Corporation to demonstrate significant reductions of SO_2 and NO_x emissions when compared to existing and future conventional coal-fired power plants. In addition, this project demonstrates the technical feasibility of commercial scale IGCC and Hot Gas Clean Up (HGCU) technology.

The Polk Power Station achieved "first fire" of the gasification system on schedule in mid-July, 1996. Since that time, significant advances have occurred in the operation of the entire IGCC train. This paper addresses the operating experiences which occurred in the start-up and shakedown phase of the plant. Also, with the plant being declared in commercial operation as of September 30, 1996, the paper will discuss the challenges encountered in the early phases of commercial operation. Finally, the future plans for improving the reliability and efficiency of the Unit in the first quarter of 1997 and beyond, as well as plans for future alternate fuel test burns, are detailed.

The presentation will feature an up-to-the-minute update on actual performance parameters achieved by the Polk Power Station. These parameters include overall Unit capacity, heat rate, and availability. In addition, the current status of the start-up activities for the HGCU portion of the plant will be discussed.

INTRODUCTION

Over the last seven years, Tampa Electric Company has taken the Polk Power Station from a concept to a reality. We have previously reported on the permitting, engineering, construction, contracting and staffing status of the project. We would like to concentrate in this paper on our recent checkout and startup experience and to discuss our operating history to date. We will also review our plans for 1997. In order to view our operations results in the proper perspective, it will be helpful to first briefly discuss some background of the Polk Power Station Project.

BACKGROUND

PARTICIPANTS

Tampa Electric Company (TEC) is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly-owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and utilization. TEC has about 3650 MW of generating capacity. Over 97 percent of TEC's power is produced from coal. TEC serves over 500,000 customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TECO Power Services (TPS) is a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-regulated utility generation market. TPS currently owns and operates a 295 MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and TEC are purchasing the output of this plant under a twenty-year power sales agreement. In addition, TPS owns and operates a 78 MW plant in Guatemala.

TPS is responsible for the overall project management for the DOE portion of this IGCC project. TPS is also concentrating on commercialization of this IGCC technology as part of the Cooperative Agreement with the U.S. Department of Energy.

The project is partially funded by the U.S. Department of Energy (DOE) under Round III of its Clean Coal Technology Program. Use of a new hot gas clean-up system (HGCU) on a 10% slip stream of syngas will highlight this demonstration of IGCC technology.

OBJECTIVES

The Polk unit is an integral part of TEC's generation expansion plan. TEC's original objective was to build a coal-based generating unit providing reliable, low-cost electric power. IGCC technology will meet those requirements.

Demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such a plant can achieve significant reductions of SO_2 and NO_x emissions when compared to existing and future conventional coal-fired power plants. In addition, this project is expected to demonstrate the technical feasibility of a commercial scale IGCC and HGCU technology. With the exception of the HGCU, only commercially available equipment has been used for this project. The approach supported by DOE is the highly integrated arrangement of these commercially available pieces of hardware and systems, in a new arrangement which is intended to optimize cycle performance, costs, and marketability at a commercially acceptable size of nominally 250 MW (net). Use of the HGCU will provide additional system efficiencies by demonstrating the technical improvements realized from cleaning syngas at a temperature of about 1000°F rather than utilizing more traditional cold gas clean-up (CGCU) methods: cooling the gas to about 100°F before the sulfur removal process. This low temperature process has the disadvantage of the irreversible cooling losses and associated reheating before admitting the syngas to the combustion turbine (CT).

SITING

The plant site is a 4300-acre tract about 11 miles west of Fort Meade and 11 miles south of Mulberry in Polk County, Florida. The process through which this site was selected is one of the many success stories of the project.

In late 1989, TEC formed an independent citizen's task force made up of 17 people representing environmental and community leaders, educators, and economists to help guide the site search. Some of the various groups who had members on the task force were: The National Audubon Society, Florida Audubon Society, 1000 Friends of Florida, Sierra Club, The Hillsborough Environmental Coalition, University of South Florida, and others. We made sure that at least half of the group was comprised of members of the environmental community. We knew that protecting the environment would be a very high priority in selecting the plant's technology and site.

The task force conducted a year-long study of more than 35 sites in six counties with the assistance of a professional environmental consulting firm.

The task force ultimately decided - after much debate - that it was better to recommend sites that had already been touched by industry. In their final analysis, they recommended three former phosphate tracts in southwest Polk County. They believed it was best, from both an environmental and economic standpoint, to place previously mined phosphate land back into productive use.

With that recommendation in hand, we began negotiations with the land owners. That is how we came to select the site we have today.

This proactive approach to siting has been very successful for us. We have established strong support for our project and are maintaining a high level of interaction with the community so that we can maintain that support.

We have employed a process of open and regular communications with the local community, our customers, and the media demonstrating that, even in today's environmental climate, we can successfully site and build coal-fired generation.

In a recent survey, three out of four of our customers agreed that we need to build this facility. Two out of three think we made the right decision to use coal. Many of you know that these results are virtually the opposite of current national trends in public opinion. We will continue with our communications-based approach to this project, just as we have with all of our operations within Tampa Electric.

CAPITAL COST

The total project capital cost was approximately $510 million, which includes DOE's $122 million cost share. At about $2,000 / kW, this seems high in comparison to the commercial offerings of other technologies. However, we must consider three mitigating factors:

- Polk Power is a first-of-a-kind design. The next similar plant should be able to build on Polk's experience base to significantly reduce costs in several areas.

- Polk's capital costs include expenses for development and reclamation of the entire 4300 acre site up to its permitted capacity of 1150 MW. The Polk site should satisfy TEC's plant site needs for the next 10 to 20 years.

- Polk has two parallel gas clean-up systems.

- Polk Power is a very clean plant utilizing our most abundant indigenous fuel resource, coal.

Considering these factors, we expect the next generation of IGCC plant to cost between $1200 and $1500 when compared on a consistent basis to other technologies. Given the trend in environmental costs for new plants and the likely long term cost and availability of coal, IGCC appears quite attractive.

TECHNICAL DESCRIPTION

A general flow diagram of the entire process is shown in Figure 1.

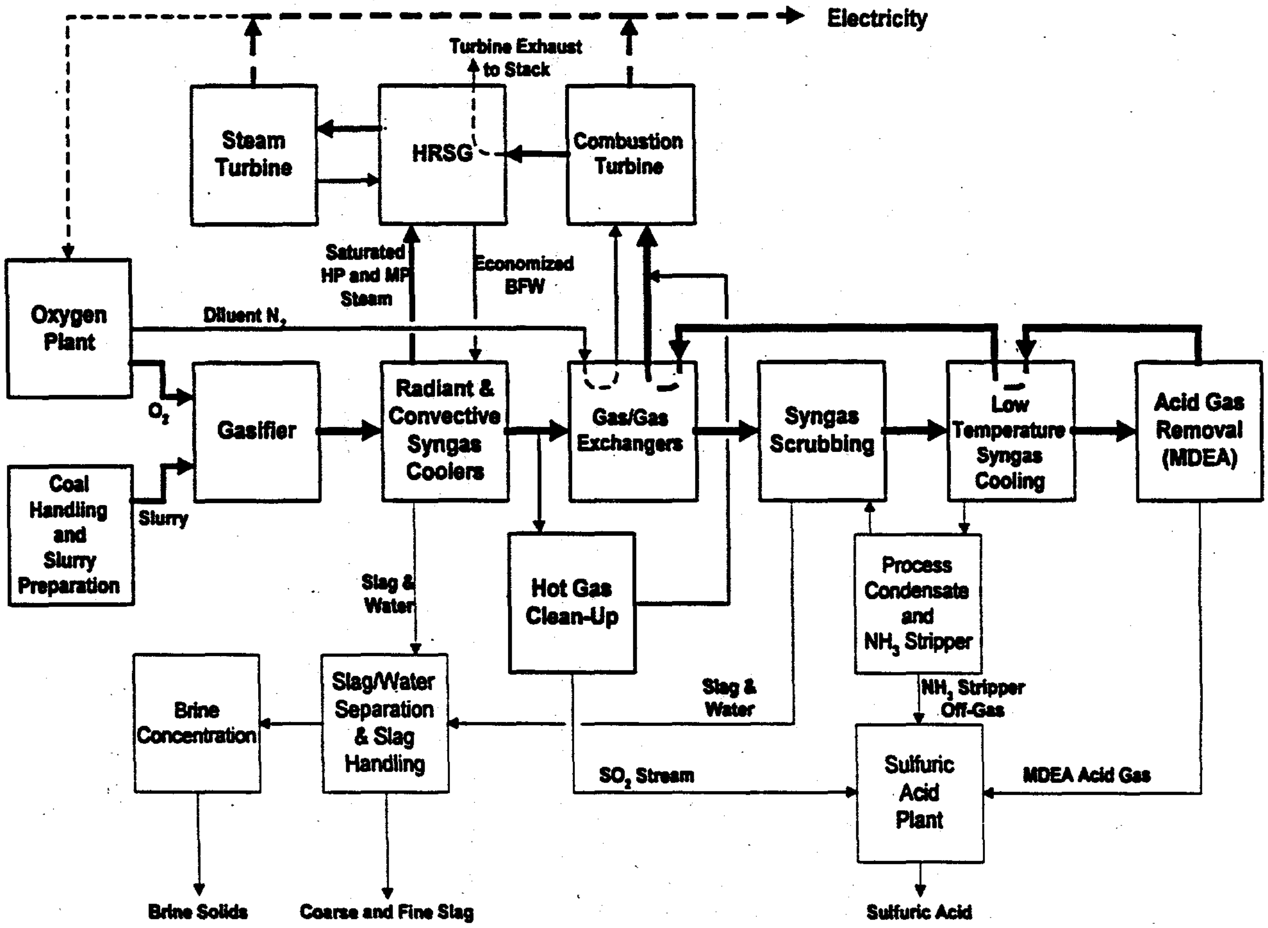


FIGURE 1
Polk Unit #1 IGCC Block Flow Diagram

This unit utilizes commercially available oxygen-blown entrained-flow coal gasification (CG) technology licensed by Texaco Development Corporation. In this arrangement, coal is ground to specification and slurried in water to the desired concentration (60-70 percent solids) in rod mills. The unit is designed to utilize about 2200 tons per day of coal (dry basis). This coal slurry and an oxidant (95 percent pure oxygen) are then mixed in the gasifier feed injector. This produces syngas with a heat content of about 250 BTU/SCF (LHV). The oxygen is produced in an air separation unit (ASU). The gasifier is designed to achieve greater than 95 percent carbon conversion in a single pass. The gasifier is a single vessel feeding into one radiant syngas cooler which was designed to reduce the gas temperature to 1400°F.

After the radiant cooler, the gas is split into two (2) parallel convective coolers, where the temperature is further reduced to less than 900°F. A 10% slip stream goes to the HGCU system and the remainder is processed in a traditional CGCU system.

The CGCU system is a traditional amine scrubber type. Sulfur removed in the HGCU and CGCU systems is recovered in the form of sulfuric acid. This product has a ready market in the phosphate industry in the central Florida area. It is expected that the annual production of 45,000 tons of sulfuric acid produced by this 250 MW (net) IGCC unit will have minimal impact on the price and availability of sulfuric acid in the phosphate industry.

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

The water in the slag lockhoppers requires treatment before it can be reused. All of the water from the gasification process is cleaned and recycled, thereby creating no requirement for discharging process water from the gasification system.

The ASU uses ambient air to produce oxygen for use in the gasification system and sulfur recovery unit, and nitrogen which is sent to the advanced CT. The addition of nitrogen in the CT combustion chamber has dual benefits. First, this additional mass flow has the advantage of producing higher CT power output. Second, the nitrogen acts to control potential NO_x emissions by reducing the combustor flame temperature which, in turn, reduces the formation of thermal NO_x in the fuel combustion process.

The ASU is sized to produce about 2100 tons per day of 95 percent pure oxygen and 6300 tons per day of nitrogen. The ASU was provided by Air Products.

The HGCU system is being developed by General Electric Environmental Services, Inc. (GEESI). Instead of having to cool the gas prior to sulfur removal, the HGCU will accept gas at 900-1000°F. The successful demonstration of this technology will provide for higher efficiency IGCC systems.

A regeneration system for the HGCU will produce a concentrated (about 13 percent) SO_2 stream. This will feed a sulfuric acid plant, for production of a saleable acid byproduct.

Other support processes will also be tested in conjunction with HGCU:

- In addition to the high efficiency cyclones upstream of the HGCU system, a high temperature barrier filter is installed downstream of the HGCU to protect the CT.

- Sodium bicarbonate, $NaHCO_3$, will be used upstream of the HGCU sorbent bed for removal of chloride and fluoride species. The resulting stable solids sodium chloride and sodium fluoride will be disposed of with other plant solid byproduct streams.

The key components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and electric generators. The power block is provided by General Electric.

The HRSG is installed in the CT exhaust to complete the traditional combined cycle arrangement and provide steam to the 130 MW ST. No auxiliary firing is done in the HRSG system. Hot exhaust from the CT is channeled through the HRSG to recover the CT exhaust heat energy. The HRSG high pressure steam production is augmented by high pressure steam production from the coal gasification plant. All high pressure steam is superheated in the HRSG before delivery to the high pressure ST.

The ST is a double-flow reheat turbine with low pressure crossover extraction. The ST and associated generator are designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1450 psig and 1000°F with 1000°F reheat inlet temperature.

The operation of the combined cycle power plant is coordinated and integrated with the operation of the CG process plant. The initial startup of the power plant is carried out on low sulfur No. 2 fuel oil. Transfer to syngas occurs upon establishment of fuel production from the CG plant.

Under normal operation, syngas and nitrogen from the ASU are provided to the CT. The syngas/nitrogen mix at the CT combustion chamber is regulated by the CT control system to control the NO_x emission levels from the unit.

Cold reheat steam from the high pressure turbine exhaust and HRSG intermediate pressure steam are combined before reheating in the HRSG and subsequent admission to the intermediate pressure ST. Some intermediate pressure steam is also supplied to the HRSG from the sulfur recovery unit.

The heart of the overall project is the integration of the various pieces of hardware and systems. Maximum usage of heat and process flow streams can increase overall cycle effectiveness and efficiency. In our arrangement, benefits are derived from using the experience of other IGCC projects, such as the Cool Water Coal Gasification Program, to optimize the flows from different subsystems. For example, low pressure steam from the HRSG is produced to supply heat to the CG facilities for process use. The HRSG also receives steam energy from the CG syngas coolers to supplement the steam cycle power output. Additional low energy integration occurs between the HRSG and the CG plant. Condensate from the ST condenser is returned to the HRSG/integral deaerator by way of the CG facilities, where some condensate preheating occurs by recovering low level heat.

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

The primary source of emissions from the IGCC unit is combustion of syngas in the advanced CT (GE 7F). The exhaust gas from the CT leaves the system via the HRSG stack. Emissions from the HRSG stack are primarily NO_x and SO_2 with lesser quantities of CO, VOC, and particulate matter (PM). The

CGCU and HGCU systems are designed to remove at least 96 percent of the sulfur present in the coal. The emission control capabilities of the HGCU system are yet to be fully demonstrated. Therefore, some emission estimates are higher compared to estimated emissions from the CGCU system. After the completion of the two-year, phase-one demonstration period, the lower emission rates from the CGCU system must be achieved to meet permit requirements.

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

Part of our cooperative agreement with DOE is a four-year demonstration phase. During the first two years of this period, it is planned that four different types of coals will be tested in the operating IGCC power plant. The results of these tests will compare this unit's efficiency, operability and costs, and report on each of these test coals specified against the design basis coal, Pittsburgh #8. These results should provide a menu of operating parameters and costs which can be used by utilities in the future as they make their selection on methods for satisfying their generation needs, in compliance with environmental regulations.

EARLY OPERATING HISTORY

Third Quarter, 1996: Start-up and Commissioning:

First syngas was produced on July 19, 1996. The first gasifier run lasted 21.5 hours which set the longevity record for first fire on a solid fuel Texaco gasifier. Ten gasifier runs totaling 174 hours were completed during the third quarter. All plant systems had been successfully commissioned by the end of this period, so Polk Power Station Unit #1 was placed in commercial operation at the end of the third quarter on September 30, 1996. The major accomplishments and shutdown causes of the first ten runs are summarized in Table 1.

TABLE 1
Gasifier Runs, Major Accomplishments, Shutdown Causes
Commissioning Phase (Third Quarter, 1996)

Run Number	Duration (Hours)	Major Accomplishments	Shutdown Cause
1	21.5	First Syngas	Process Water Plugging - Clarifier
2	5.6		O_2 Flow Set Point Entry
3	29.5	Lined Out Process Water System	Loss of BFW from Power Block
4	10.3	First Time Through Low Temperature Gas Cooling	MDEA Foaming and Carry-Over
5	4.1		Raw Gas Flare Valve I/P Failure
6	3.7		False Indication of Cooling Water Loss
7	6.7		Lockhopper Problems
8	67.3	First Steady MDEA Operation	Process Water and Convective SGC Plugging
9	2.4		HP BFW Valve Failure
10	22.4	100% Gasifier Load, First Syngas to CT, First H_2SO_4, First Brine Crystals	CT Fuel Oil Leak, Convective SGC Plugging

Fourth Quarter, 1996: Initial Commercial Operation:

Ten gasifier runs totaling 701 hours were made in October and November, 1996, prior to a planned outage which began December 5 for routine maintenance, inspections, and some minor improvements. In the 30 days preceding the outage, the gasifier was on-line 67% of the time and the gas turbine was on 100% syngas fuel 59% of the time. This was a major accomplishment which exceeded our target expectations for this period. The longest continuous gasifier run was 7.5 days, and the combustion turbine was on syngas fuel continuously for 7.3 days during this run. The last four gasifier runs were shut down by transmission system voltage swings external to the plant. The protections systems have been reconfigured so even minor external disturbances such as these will no longer trip the unit. These runs are summarized in Table 2.

TABLE 2
Gasifier Runs, Shutdown Causes
Early Commercial Operation (October and November, 1996)

Run Number	Duration (Hours)	Turbine On Syngas (Hours)	Shutdown Cause
11	31.2	2.8	Convective SGC Plugging
12	101.6	16.8	Combustion Turbine Vibration-Rotor Bolt
13	81.9	51.4	Steam Turbine Trip (Excitation) Caused BFW Loss
14	4.5	0.0	Lockhopper Problems
15	54.2	40.4	Steam Turbine Trip (Excitation) Caused SGC Drum Upset
16	17.9	0.0	Main Air Compressor Trip - Execution of DCS Change
17	153.8	149.0	Oxygen Compressor Trip - Transmission System Voltage Swing
18	4.5	0.0	Slurry Feed Pump Trip - Transmission System Voltage Swing
19	71.0	64.6	Main Air Compressor Trip - Transmission System Voltage Swing
20	180.1	174.7	Slurry Feed Pump Trip - Transmission System Voltage Swing

Specific operational experiences and challenges during the commissioning and initial commercial operational phases are detailed below.

AIR SEPARATION

The oxygen plant has operated essentially trouble free through both the commissioning and initial commercial operational phases. Early high vibration of the main air compressor motor has been reduced to normal levels. Three recent gasifier trips have resulted from oxygen plant trips due to problems external to the oxygen plant itself. Polk Power Station does not have a backup liquid oxygen supply system which could have saved these gasifier runs. When backup systems were being evaluated in the design phase, their cost could not be justified based on the expected incremental availability they were expected to provide. This is probably still the case, but TEC will continue to monitor the frequency of ASU plant trips.

The process performance of the oxygen plant has been exceptionally good. It comfortably met its rated production under hot ambient conditions with all product purities better than design and with capacity still available on the columns, exchangers, and compressors. Power consumption appears to be generally consistent with our expectations, but because of the number of variables involved, it must still be checked during a detailed performance test.

The advanced controls handle minor perturbations around steady state well, and we now always operate with them engaged. They adjust the feed air flow and internal flows based on the demand for the various products.

SLURRY PREPARATION

Slurry preparation performed extremely well during the commissioning phase. For three months, we produced stable, pumpable slurries up to 64% concentration without the use of additives with virtually no operational problems. Early high vibration of the rod mills was quickly eliminated by reinforcing the foundations. However, some severe problems did develop beginning early in the fourth quarter of 1996. Specifically, we observed:

- Settling and partial plugging in many horizontal piping runs (reduced pumping capacity and caused instrumentation problems)
- Severe liner wear on the slurry transfer pumps (reduced pumping capacity)
- Overflowing of the slurry screens (operational problems)
- pH swings in the product slurry (corrosion of tanks and piping)
- Failure of the purge water filter (operational problems)

Factors which may have contributed to some or all of these problems are as follows:

- Variations in feed coal properties have been observed. Distinct property variations in the off-site coal pile have been documented, apparently due to weathering and/or aging; and aging in the on-site coal storage silos is also likely. This seems to be linked to the pH swings.

- The installed slurry screens are finer than Texaco had specified and the pump manufacturer required. This contributes to the problem of overflowing screens.

- A low dose rate of viscosity reducing additive has been used occasionally. This temporarily facilitates pumping, but may contribute to the line plugging in the long term.

- Rod loading in the mills has been adjusted several times to try to fine tune the particle size distribution.

We are addressing these problems through a series of steps such as installing appropriately sized slurry screens, restoring the initial rod loading of the rod mills, and more carefully monitoring and controlling the slurry pH with ammonia injection. Some additional modifications may be required once these easier changes are completed.

GASIFIER

The gasifier itself is quite simple and it has performed reliably throughout the commissioning and early commercial operational phases.

The gasifier safety system performance has been excellent to date. We have had no nuisance shutdowns - all automatic shutdowns have been the result of problems in other parts of the plant which properly tripped the unit. The gasifier feed controls have also been excellent. These adjust the overall gasifier load as well as the ratio of oxygen to slurry to control gasifier temperature.

Thermocouple life had been a problem in the commissioning phase. However, early in the operational phase, we began running at lower temperatures which prolonged thermocouple life. Also, the on-line analyzers were proven sufficiently reliable and, in parallel, useful correlations between gasifier temperature and the syngas composition were developed. Consequently, although thermocouples are still necessary at times and they must still be replaced more often than we would prefer, concern and expense in this area has been significantly reduced. Additional development work is underway to further increase thermocouple life and reduce cost.

During the commissioning phase, we observed the performance of the gasifier at various temperatures, loads, and slurry concentrations. Some minor feed injector design changes were made as a result. We believe the operating conditions are now near optimum for this feed injector design and refractory liner.

The following Table 3 shows that some aspects of the gasifier's performance at current operating conditions that do not yet meet "Design" or "Commercially Expected" values.

TABLE 3
Slag Characteristics and Refractory Liner Life

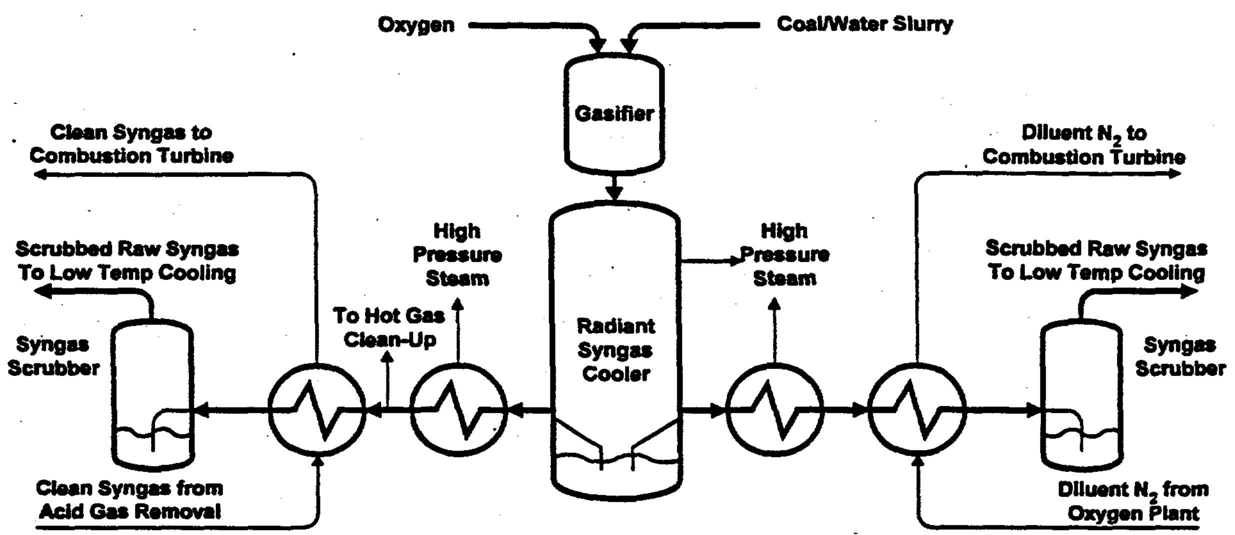
	Current Full Load Operation	Design or Commercial Expectation
Slag Carbon Content (Weight % Dry Basis)	34	14 to 28
Slag Quantity (Dry Tons/Day)	250	185 to 215
Heating Value Lost To Slag (MMBTU/Hr HHV)	70	20 to 50
Refractory Liner Life (Years at 85% On-Stream Factor)	½	2

Carbon conversion can be increased at the expense of refractory liner life, and vice-versa, by adjusting gasifier temperature. However, as can be seen from the table, there is little available to sacrifice on either parameter. The higher than expected carbon content of the slag creates handling problems and makes it a less desirable byproduct for many applications. It also increases the mass and volume of the material we must handle. Furthermore, the heating value of the carbon lost with the slag increases net plant heat rate by 75 to 200 BTU/KWH. The current "startup" gasifier refractory liner is less expensive with reduced slag resistance compared to the material we expect to use long-term. Our first liner replacement is scheduled for the spring of 1997. It will be a more slag-resistant material, so at current operating conditions, it may approach our commercial expectations of a 2 year liner life. However, some additional feed injector adjustments to improve carbon conversion at less severe reactor conditions are still required for us to realize our commercial expectations for liner life, heat rate, and slag quantity/quality. Texaco has an excellent team on-site and at other Texaco engineering and development centers working with us on these issues.

HIGH TEMPERATURE SYNGAS COOLING

High Temperature Syngas Cooling consists of a Radiant Syngas Cooler (RSC) followed by Convective Syngas Coolers (CSC).

FIGURE 2
Syngas Cooler System



Raw syngas from the gasifier first passes downward through an RSC where high pressure steam is generated. The CSC System consists of two wings, each of which handles 50% of the RSC outlet gas. Each wing consists of a fire-tube convective heat exchanger producing high pressure steam, followed by a two stage gas/gas heat exchanger where the raw syngas (tube side) heats either the clean syngas or diluent nitrogen to the combustion turbine.

The RSC and its associated steam systems have been trouble-free through both the commissioning and early operational phases. Fouling factors have been only ⅓ of the design value with Pittsburgh #8 coal, so no soot-blowing has been required. Fouling has been so low that we may need to elevate the RSC outlet temperature by covering part of the RSC surface with insulating refractory to meet the HGCU minimum inlet temperature requirement. Soot blowing may be required as we achieve longer run times and gasify other coals, but all indications are that we will have no difficulty achieving target heat transfer. There have been no hints of plugging in the RSC.

As with the RSC, heat transfer in the CSC exchangers has recently been excellent. Fouling factors have been 30% or less of design values where we could measure them.

One of the greater challenges during the commissioning phase was pluggage within the CSC system. Many of the gas/gas exchanger tubes plugged with ash deposits during several of the commissioning phase runs. This increased the pressure drop above the allowable level, so it was necessary to cool, open, enter, and clean this equipment often. The deposits absorbed moisture during this downtime, some from the ambient air and some from other sources. This produced rapid downtime corrosion. Pits penetrated through up to 60% of the tube wall thickness in some places. Fortunately, very early in the operating phase, we learned how to eliminate this plugging by controlling temperatures and velocities in the equipment. Also, we have been more careful in our shutdown and startup practices to minimize conditions leading to downtime corrosion. The inspection during the December, 1996, planned outage revealed no plugged tubes and no increased corrosion.

LOW TEMPERATURE GAS COOLING (LTGC)

Immediately downstream of the CSC's are the Syngas Scrubbers where particulates and chloride are removed from the raw syngas in a water wash. The raw syngas is water saturated as it leaves the scrubbers at about 300°F. The LTGC system cools the syngas to near ambient temperature for the acid gas removal system. As the gas cools, most of the water vapor condenses and becomes what is referred to as process condensate. The LTGC system consists of three partially condensing heat exchangers and associated knock-out drums, the process condensate return system, and an ammonia stripper to rid the system of the ammonia which condenses from the syngas with the process condensate.

The system has generally performed well to date. Some minor modifications were made to accommodate the somewhat different than expected flow rates of process condensate from some of the exchangers. The greatest difficulties have been in the ammonia stripper overhead piping. Ammonia combines with carbon dioxide to form solid salts which plug the piping if the temperature falls below about 160°F. Heat tracing was inadequate in some line segments and it was completely overlooked in others. Furthermore, the piping and control valves were inadequately sized, and this has prevented us from feeding this entire stream to the Sulfuric Acid Plant where the ammonia is to be converted to nitrogen and water vapor. These problems have been corrected and we expect no further difficulty with the LTGC system.

ACID GAS REMOVAL

A tertiary amine (MDEA) system is being used in the Polk plant for removing hydrogen sulfide (H_2S) from the raw syngas in the cold gas clean-up (CGCU) system.

We experienced a significant amount of foaming when we first introduced syngas to the MDEA absorber during Gasifier Run #4 early in the Commissioning Phase. Foaming is a known problem with all amine based acid gas removal systems. We quickly brought this foaming under control with filtration and anti-foam agents and have experienced no foaming during subsequent runs. However, some amine contamination of other plant systems persists, probably through a slight amount of carry-over with the clean syngas during startup. This amine finds its way into the grey water system, and ultimately into the brine concentration unit where it causes foaming in the falling film evaporator. This foaming must also be controlled with anti-foam agents.

Tuning of the MDEA system operation continued through the remainder of the commissioning phase, and clean gas within Polk's environmental requirements was consistently being produced by the beginning of the fourth quarter of 1996. 95% overall sulfur removal is achieved. The MDEA now routinely removes 99% or more of the H_2S. The remainder of the sulfur emissions are derived from carbonyl sulfide (COS), a compound which our plant configuration and MDEA solvent are not designed to remove. The gasifier produces more COS than was expected, and we are hoping the high COS production rate observed to date is peculiar to the Pittsburgh #8 coal we are now running. If it is not, we may have to change solvents, adjust operating conditions, and possibly make other modifications to run higher sulfur coals within our current permit limits.

While the MDEA does remove virtually all the H_2S, it typically only removes about 12% of the carbon dioxide (CO_2) from the syngas. The plant design assumed 20% of the CO_2 would be removed. This extra CO_2 in the syngas improves overall plant efficiency by increasing the "free" mass flow to the turbine and reducing the steam required to regenerate the solvent.

A steady rise in the concentration of degradation products has occurred in the MDEA solvent but not at an unexpected rate. A water wash column is installed upstream of the absorber to remove trace compounds to minimize formation of these MDEA degradation products. We have not yet built sufficient operating history to evaluate its effectiveness.

SULFURIC ACID PLANT

The Acid Gas Removal system produces the main feed stream for the Sulfuric Acid Plant, an acid gas stream consisting of 20% to 30% H_2S and most of the remainder CO_2. The other main feed stream is the Ammonia Stripper off-gas. The Sulfuric Acid Plant has performed very well once steady, efficient operation of the Acid Gas Removal system was achieved early in the fourth quarter. The plant has tripped four times due to pressure fluctuations of the feed streams. These were not related to the Acid Plant itself.

The Pittsburgh #8 coal we are currently gasifying has a sulfur content of less than 2.5%, compared to a design concentration of 3.5%. As a result, 1 to 2 MMBTU/Hr of supplemental fuel is sometimes required as expected to maintain temperature in the catalytic reactors.

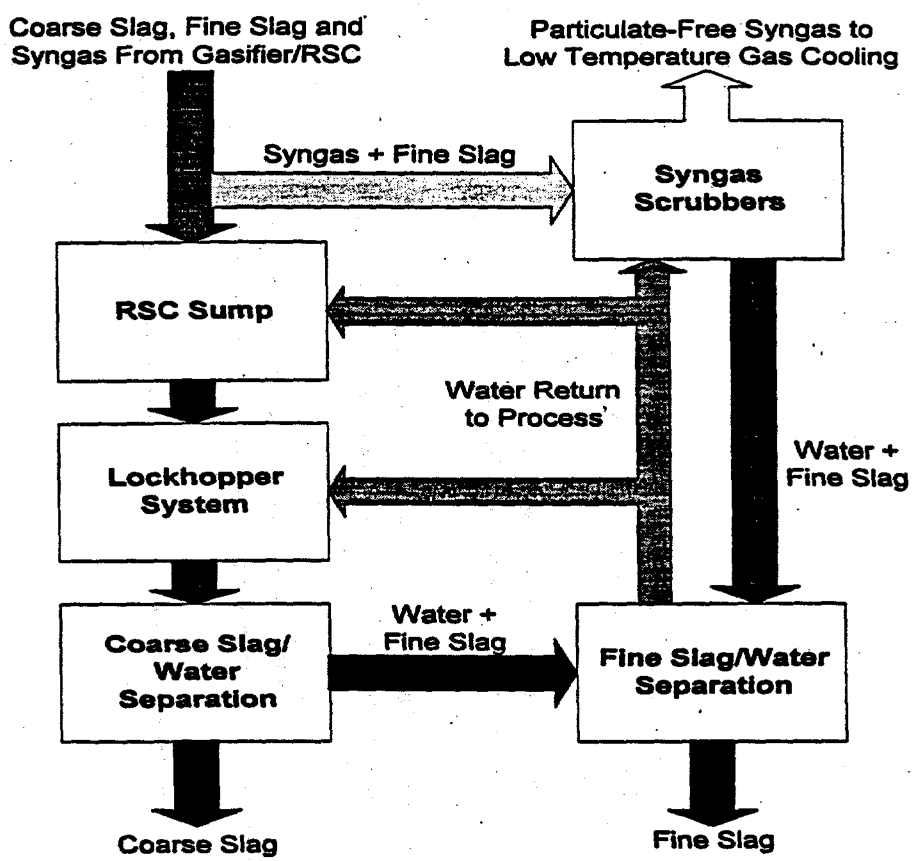


FIGURE 3
Process Water Systems, Fine and Coarse Slag Handling

Coarse slag and some of the fine slag from the gasifier falls through the RSC into a water pool at the bottom. This pool is referred to as the RSC Sump. From there, the slag is removed via a lockhopper system which cycles approximately twice per hour. With each cycle, the water and slag mixture from the lockhopper dumps into a concrete holding area where it is separated (Coarse Slag/Water Separation). The coarse slag is hauled to the slag holding area. The water, containing some fine slag, is pumped to the Fine Slag/Water Separation System.

The fine slag which does not fall into the RSC sump passes through the CSC system with the syngas and is removed in the syngas scrubbers. Fine slag and water are continuously blown down from the scrubbers. This stream is also routed to the Fine Slag/Water Separation system.

Fine Slag/Water Separation consists first of a settler where the fines are concentrated. The fines in the settler bottoms are then removed in a rotary drum vacuum filter and are also hauled to the slag holding area. The water is returned to the process.

The fines removal system has performed beyond expectations. It typically handles much more water and fines than design. During the commissioning phase, upsets of the settler did occur due to excessive traffic and/or loss of polymer feeds. This led to solids carryover from the gravity settler, resulting in plugged process piping. These problems have been largely eliminated in early commercial operation with operating experience.

Likewise, the lockhopper, RSC sump, and syngas scrubbers also experienced some plugging in the Commissioning Phase during periods of excessive solids traffic, but these problems also have been resolved with experience and some minor piping modifications. Erosion has been encountered in some control stations during early commercial operation. This was not unexpected, and it is being addressed with materials and configuration changes.

The Coarse Slag/Water Separation system has been a challenge. The water was expected to easily separate from the slag in the concrete holding area after each lockhopper dump. However, the fine slag stayed in suspension. These fines plugged the local sump and increased the loading on the gravity settler. Barrier walls were installed in the slag holding area and the water is now pumped off in batches after settling. This added settling time greatly reduces the fine slag in the water. The system is now operable, but still very labor intensive. Significant configuration changes are being considered for the long term.

BRINE CONCENTRATION

The Polk Power station is permitted as a zero process water discharge facility requiring that all of the process water is recovered and reused. Through recycling, the chlorides removed from the syngas in the Syngas Scrubber would build to unacceptably high levels for affordable metallurgy. Therefore, a brine concentration system was incorporated into the plant design. It consists of a falling film evaporator, followed by a forced circulation evaporator feeding a crystallization and centrifuge separation step.

During the third quarter, the falling film unit was commissioned with excellent results. As previously mentioned, foaming problems resulting from amine in the feed has resulted in the greatest operational problems such as sump level control and carryover. Anti-foam agents have been effective, and a permanent anti-foaming injection system is being pursued.

The forced circulation evaporator has been the greatest challenge in operating the brine concentration unit in the early commercial phase. Corrosion has been excessive. Using corrosion coupon tests, coupled with laboratory tests, the corrosion mechanism is being understood which will lead to metallurgical and process modifications in this system.

Control of the centrifuge has been difficult, resulting in crystals of variable quality. We believe this is due in large part to erratic flows causing periodic line pluggage. The control scheme is being modified.

COMBINED CYCLE

The key components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and electric generators. The combined cycle power plant was provided by General Electric.

The CT is a modified Frame 7F capable of producing 150 MW (gross) from #2 fuel oil (the startup and backup fuel) and 192 MW (gross) from syngas fuel. When firing syngas fuel, nitrogen from the ASU provides both NO_x abatement and power augmentation.

Hot exhaust from the CT is channeled through the HRSG to recover energy. The HRSG performs most of the plant's economizing and all of the superheating, while most of the high pressure steam is generated in the syngas coolers when the gasifier is on line. The HRSG also produces much of the low pressure steam consumed by the gasification plant. Consequently, Polk's HRSG contains significantly more superheater, economizer, and low pressure evaporator surface compared to HRSGs in conventional combined cycles.

The 130 MW ST is a double-flow reheat turbine. Nominal turbine inlet steam conditions are 1450 psig and 1000°F with 1000°F reheat temperature. Low pressure extraction provides the remainder of the low pressure steam for the gasification plant.

The combined cycle was commissioned on May 4, 1996. Ever since, it has been dispatched as a normal Tampa Electric generation resource. It has produced approximately 150,000 megawatt hours on distillate fuel and 200,000 megawatt hours on syngas fuel through the end of 1996.

The combustion turbine was first operated on 100 percent syngas fuel for 4.1 hours during Gasifier Run #10 in mid September. It reached a maximum load of 161 MW on syngas, generating 520 megawatt hours over this period. Combined cycle output reached 210 MW. However, this first period of operation on syngas revealed a design problem with the fuel nozzles which led to some local overheating. The combined cycle was out of service for the remainder of September for repairs and modifications. This problem has not recurred.

A brief period of operation on syngas fuel occurred during a short gasifier run on October 1. During the next gasifier run, Run 12, the CT reached full syngas load (192 MW gross) on October 13. This run was highly successful, but it did identify two additional problems:

1) Performance data during this run showed that the diluent nitrogen control valve was undersized for the design flow. Diluent N_2 is used for NO_x abatement, and sufficient N_2 could only be provided to keep NO_x emissions within permit limits with a CT output of 185 MW (gross). A larger valve is due in February, 1997.

2) GE observed high CT vibration on October 16. Their on-line diagnostics showed this was caused by a crack in a large turbine rotor bolt. GE replaced all these bolts in the subsequent 11 day outage. The CT has had no further high vibration problems.

ST excitation system failures caused ST trips on October 31 and November 6. These led to gasifier trips due to an incorrect valve lineup in the Hot Gas Cleanup System which had not yet been commissioned. These trips clearly demonstrate some of the drawbacks of integration: problems in one process unit can create even greater problems in another. The valve lineup was quickly corrected once it was found, and subsequent ST trips have not caused gasifier trips. We believe we have also finally found and corrected the cause of ST excitation system failures.

The best combined cycle performance prior to the December planned outage occurred during gasifier Run 20 from November 26 to December 4. The gasifier was on line continuously for 180 hours and the CT was on syngas fuel continuously for 175 hours. The average gross power production for the entire period was 300 MW, 184 MW from the CT and 116 MW from the ST.

At the time of printing of this paper, Gasifier Run #22 was still in progress. Through January 5, the gasifier had been on-line continuously for 306 hours and the CT had been on syngas fuel for a total of 296 hours and continuously for 267 hours.

Starting reliability of the CT on distillate fuel has been good, but fuel transfers to syngas fuel have been inconsistent. The first attempts to transfer the combustion turbine to syngas fuel in August were unsuccessful. Corrections were made, and the next attempt in mid-September went smoothly. But new problems appeared and there were 3 failed transfer attempts during gasifier Run 16 in early November. The CT never successfully transferred to syngas fuel in 18 hours of gasifier operation during that run. However, in mid and late November, transfers were smooth and routine. The purge system and the CT control system were modified in the December outage. Despite the changes, fuel transfers again were problematic in late December. We are hoping for a speedy resolution once all purge system modifications are completed and the controls are retuned.

CONTROL SYSTEM

The plant's main control system is a Bailey Infi-90 Distributed Control System (DCS). The DCS communicates directly with 3 other plant control systems: the CT GE Mark V, the ST GE Mark V, and the Triconex Gasifier Safety System. There are about 7200 direct Input/Output variables. Over 500 process control graphics available on any of 14 CRT screens provide the operator interface.

The DCS has performed well. No gasifier or plant trips have been caused by DCS module or I/O failures. The overall DCS availability in fourth quarter of 1996 was 100.0 %.

Two systems associated with the DCS have also been highly successful: 1) the data storage, and 2) retrieval system and the operator training simulator. It is not an exaggeration to say that the Polk plant would not be running as well as it is today without these systems.

- Data storage and retrieval is done by a product called Plant Information Systems (PI) from Oil Systems Inc. Data storage has been almost 100% reliable, and retrieval is easy in several different formats (graphs, tables, spreadsheets).

- The operator training simulator was furnished by Bailey and TRAX, Inc. A copy of the actual plant control system (DCS and Triconex hardware and software) interacts with process plant models running on seven PC's. This simulator enabled plant personnel to become familiar with plant operation before startup and correct control system and procedural errors before they occurred in the real plant.

Although the DCS has performed well, the required level of technical support has been higher than expected to achieve these results. A full-time team of seven with some supplemental help worked throughout most of 1996 to address the following issues:

- DCS module infant mortality was fairly high in the Commissioning Phase, but failure rates have declined dramatically. All failed modules were replaced under warranty.

- Initially there were over 8000 possible alarms, and at times during the Commissioning Phase over 1000 of these were simultaneously active. Such information overload causes alarms to be ignored. A separate "alarm team", formed late in the Commissioning Phase, reduced the number of alarms to about 4000. Further reduction in the number of possible alarms and prioritization of the remaining alarms is still in progress.

- Conveying information which can be quickly and easily interpreted for split-second decision making is always a challenge. To meet this challenge, it has been necessary to improve plant diagnostics by adding more "first out" indications, dedicated displays, and ready lists. Graphic displays have also been modified to be more concise and easily readable. These efforts will undoubtedly continue into the foreseeable future.

- The data links between the DCS and both CT and ST Mark V control systems have been troublesome. Making changes is particularly hard. (In contrast, the data link between the DCS and the Triconex Gasifier Safety System has worked very well.) Also, working on the Mark V and GE's user interface is difficult. We must still rely more heavily on GE than we would prefer at this stage of operation. It would have been preferable to have done as many of the turbine control functions as possible directly in the DCS.

- Almost all logic and configuration errors have been eliminated, initial tuning has been done on all control loops, and some optimization has been done. However, initial operation and tuning efforts have shown that new or modified control logic will be necessary for several plant areas such as:

  -- Overall plant load control
  -- Combustion Turbine fuel transfers,
  -- pH control in water treatment,
  -- Grey Water inventory control
  -- Centrifuge control in Brine Concentration.

PLANS FOR FUTURE OPERATION

During the fourth quarter of 1996, most of our efforts were geared toward keeping the unit on line as much as possible to obtain operating experience. We are now moving into a period where we will look to improve performance and "fine tune" plant operation. Most of our efforts for 1997 will be focused primarily in four areas:

- Equipment and/or operational modifications to increase availability and reduce operating costs,
- Operational modifications to improve overall Unit heat rate,
- Continued start-up efforts for the Hot Gas Clean-Up (HGCU) system, and
- Preparation for alternate fuel test burns (DOE demonstration test burns).

INCREASE AVAILABILITY AND REDUCE OPERATING COSTS

Previous sections of this paper have touched on steps that Polk is taking to reduce some operating costs, e.g., by improving the slurry preparation and slag/water separation areas which are currently labor-intensive, and reducing corrosion in the brine concentration area. However, even greater reductions in Polk's operating costs can be realized by increasing IGCC availability. High availability is an important attribute of any type of power plant. For IGCC plants, high availability is even more important than for most since there is a stronger link between high IGCC availability and low operating costs for the reasons discussed below. Polk's IGCC availability has recently exceeded our expectations for this period, but the plant has still not reached our projections for "mature" operation and there is much room for improvement.

Reduced IGCC availability usually occurs under two conditions:

- The gasifier is off-line
- The gasifier is on-line but the CT is not on syngas fuel

Whenever the gasifier is off-line, a considerable amount of energy must be consumed for heating the gasifier, heat maintenance in other parts of the plant (steam system, Sulfuric Acid Plant) and starting or maintaining operation of the ASU. The time to return the gasifier to service after a trip can be significant. This is primarily due to various heat up and cool down rate restrictions and strict sequencing requirements in various parts of the plant to prepare for a start-up. And although the power block can usually continue operation on its back-up fuel when the gasifier is down, this is often not an attractive operating mode for IGCC plants. IGCC combined cycles are optimized for integrated operation with syngas fuel so they are likely to be less efficient than other generation options when on the back-up fuel, and back-up fuels (at least in Polk's case, distillate) can be expensive.

- The operator training simulator was furnished by Bailey and TRAX, Inc. A copy of the actual plant control system (DCS and Triconex hardware and software) interacts with process plant models running on seven PC's. This simulator enabled plant personnel to become familiar with plant operation before startup and correct control system and procedural errors before they occurred in the real plant.

Although the DCS has performed well, the required level of technical support has been higher than expected to achieve these results. A full-time team of seven with some supplemental help worked throughout most of 1996 to address the following issues:

- DCS module infant mortality was fairly high in the Commissioning Phase, but failure rates have declined dramatically. All failed modules were replaced under warranty.

- Initially there were over 8000 possible alarms, and at times during the Commissioning Phase over 1000 of these were simultaneously active. Such information overload causes alarms to be ignored. A separate "alarm team", formed late in the Commissioning Phase, reduced the number of alarms to about 4000. Further reduction in the number of possible alarms and prioritization of the remaining alarms is still in progress.

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- Almost all logic and configuration errors have been eliminated, initial tuning has been done on all control loops, and some optimization has been done. However, initial operation and tuning efforts have shown that new or modified control logic will be necessary for several plant areas such as:

  - Overall plant load control
  - Combustion Turbine fuel transfers,
  - pH control in water treatment,
  - Grey Water inventory control
  - Centrifuge control in Brine Concentration.

For each gasifier shutdown to date, to the extent that is was economically justified, the shutdown cause has been identified and corrected.

For example, Table 4 shows that the most serious factor affecting unit availability has been gas side plugging in the fire-tube heat exchangers. A significant effort was expended by Tampa Electric, Texaco, Bechtel and the equipment manufacturer, L. C. Steinmuller, to better understand the physical and chemical phenomenon which caused the plugging. Fortunately, in mid-October, TEC was able to develop empirical temperature and velocity correlations which enabled us to avoid operating in the plugging regime. There have been no shutdowns due to plugging since then. The correlations and operating procedures continue to be improved to optimize unit operation while still avoiding gas side pluggage. The phenomena which caused the plugging in the first place have not yet been positively identified, so TEC has requested Texaco, Steinmuller, and Bechtel to continue these investigations.

As another example, one of the shutdowns attributed to a valve failure was actually due to the failure of an I/P transducer. These devices inevitably fail, and providing redundancy to preclude all such failures for important valves could not be economically justified. However, we did replace the failed transducer with one from a different manufacturer whose transducers have demonstrated higher reliability in the TEC system.

The effort to identify and eliminate direct shutdown causes will continue in earnest as an extremely high priority in 1997, and probably throughout the life of the plant.

Some of the other steps which will be taken in 1997 to improve availability and reduce operating costs in the other areas are:

- To help survive operational upsets:
  - DCS operator displays, ready lists, etc., will be improved
  - The DCS "alarm team" will complete its work to eliminate nuisance alarms and prioritize the remaining ones.
  - Alternate routes for process water streams will be installed.

- To reduce gasifier turn-around and restart time:
  - Establish "hot-restart" procedures (restarting the gasifier immediately following a trip without having to preheat).

- To reduce the time between gasifier startup and when specification fuel is available to the CT:
  - Streamline procedures for placing the acid gas removal system in service

- To reduce/eliminate CT fuel transfer problems:
  - Complete modifications and tune the nitrogen purge system.

With these and other changes, we expect to improve on Polk Power's already excellent record of reliability growth.

IMPROVE UNIT HEAT RATE

To improve unit heat rate, we are primarily considering operational changes that can be made with the existing plant equipment. Due to the complex and integrated nature of the process, there are still several areas of the plant which require "shakedown" or "fine tuning". It is difficult to make multiple changes within the process and accurately track the impact on unit performance. Therefore, we have instituted a systematic plan to analyze and improve plant heat rate.

The plant engineering staff, along with the plant operators (IGCC Process Specialists), have formed various process improvement teams. These teams look at specific areas of the plant where potential improvements are available. Recommendations are evaluated and implemented by the teams and results identified. Due to the high amount of integration in the process, it is important to understand overall relationships so that improvements in one area do not have an adverse effect in another area. Table 5 summarizes the areas currently under evaluation for plant heat rate improvements.

TABLE 5
Heat Rate Improvements

Plant Area	Estimated Improvement Available
Air Separation Unit - Overall pressure balance and optimization	1.5 to 2.5 MW or approx. 75 BTU/KWH
"Other" Plant internal load	1.0 to 1.5 MW or approx. 50 BTU/KWH
Gasification - Heat Balance Optimization - Slurry Concentration - O/C Ratio - Operating Temperature - Carbon Conversion	Combined 300 to 500 BTU/KWH
Power Block and Steam Cycle Optimization	Combined 100 to 200 BTU/KWH

Current Heat Rate (BTU/KWH)	= 9300 to 9500
Improvements Identified (BTU/KWH)*	= 500 to 800
Projected Heat Rate(BTU/KWH)	= 8500 to 9000 **

* These are improvements identified based on current equipment in basically original configuration.

** Initial projections of heat rate at ISO conditions were in the 8600 BTU/KWH range and this remains our target. The numbers presented above indicate that if all the improvements identified for the current equipment are realized, we will meet or slightly beat the heat rate goal for the unit.

START-UP OF THE HGCU SYSTEM

During 1996, the HGCU system was operated without syngas to check out all the mechanical equipment and controls and to complete a cold flow attrition test with the sorbent Z-sorb III. In 1997, it is anticipated that the HGCU system will be run with the major objective of achieving steady state operation and optimizing the HGCU system using the first commercially available HGCU sorbent. During the period 1997-2000, the HGCU system will be tested using four different types of coals. Both sulfur and chlorine content will be varied by switching coals.

It was intended to have operated the HGCU system during the original check-out and start-up phase of the plant. However, the syngas temperature at the take-off to the HGCU system is significantly lower than designed. This is primarily due to the fact that the Radiant and Convective Syngas Coolers are removing more heat from the gas than anticipated. Several options are currently being evaluated to provide a suitable gas temperature to the HGCU system. Once this requirement is resolved, the HGCU test plan will resume.

The primary parameters that will be monitored are:

a) H2S removal efficiency
b) Ammonia inlet/outlet concentrations
c) Availability
d) Sorbent attrition rate
e) Consumption of power, water, air, etc.
f) Chloride removal efficiency
g) Barrier filter performance
h) Regeneration efficiency
i) IGCC cycle efficiency
j) Off-gas SO_2 purity
k) Effects of impurities on sorbent performance
l) Flyash slag removal efficiency (primary cyclone)

PREPARATION FOR ALTERNATE FUEL TEST BURNS (DOE DEMONSTRATION TEST BURNS)

Polk Power Station has initiated a 4½ year Demonstration Test Burn period designed to cover overall unit and individual subsystem/component performance parameters. The unit has been designed to utilize eastern (U.S.) caking coals. Tampa Electric and the Department of Energy have agreed on a basic test plan that will evaluate the unit performance on four distinct coals. Data collection will provide valuable information on how the IGCC process, including the HGCU system, is started up, operated in stable and load changing modes, and then shut down in a safe manner. Also, this test program will help Tampa Electric identify the least "overall" cost fuel for continued operation of Polk Power Station

Part of the test plan will also evaluate maintenance issues. Since much of the equipment being developed for this project is the first and/or largest of its kind, maintainability and reliability are as important as operability. Issues such as corrosion rates, materials of construction, and accessibility for repair will be studied.

The initial start-up and non-test burn periods will use a Pittsburgh #8 coal. Performance tests for the major components and systems are specified in the respective contracts to be done using Pittsburgh #8 coal, and occasionally a "modified" Pittsburgh #8 coal with higher than standard sulfur. The plans call for a series of short term test burns on the various alternate fuels to be evaluated. This period will be followed by a period of time available to make any modifications required to the system in order to perform a long term test burn. Next, a long term test burn will be performed.

The planned sequence for the test burns is as follows:

a) Run the unit on Pittsburgh #8 Coal
b) Introduce the test fuel for 100 hours and monitor performance
c) Return to Pittsburgh #8 coal
d) Repeat a, b, and c above for each of the selected fuels
e) Evaluate short term performance of the test fuel and determine any modifications required to perform a long term test burn
f) Institute required changes
g) Introduce the test fuel for the long term test burn
h) Evaluate the long term performance
i) Return to Pittsburgh #8 coal

Each short term test burn will last approximately 100 hours (4 days). During the short term test burn, all performance related test parameters will be collected. This data will be used for two purposes. First, it will be used to report on IGCC performance using this fuel. Second, the data will be used to ascertain the type and extent of any modifications necessary to allow the system to operate on that fuel for a long term test along with the economics associated with the modifications identified.

It is anticipated that all four coals evaluated during the short term test burns will be selected for long term tests. Each of the long term test burns will last for approximately one month. Performance parameters and operating characteristics will be monitored. In addition, evaluations of refractory wear rate, material corrosion rates and other specific areas of concern will be performed.

CONCLUSION

Polk Power Station was completed and commissioned on schedule and on budget. Recent operation has been excellent. We are very pleased with the plant's performance to date and are optimistic about the future of this clean coal technology in general and the Polk Power Plant in particular. We are looking forward to 1997 when we expect to further improve Polk's reliability, reduce operating costs, improve heat rate, commission the HGCU unit, and begin alternate coal testing.

TEC gratefully acknowledges the financial and technical support provided by the U.S. Department of Energy through their Clean Coal Technology Program. Without DOE participation, Polk Power would not have been possible. With DOE participation, we have been able to prove that IGCC can reduce NO_x and SO_x emissions in a utility scale application and advance the commercialization of this important clean coal technology.

Piñon Pine Power Project Nears Start-up

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ABSTRACT

The IGCC facility being built by Sierra Pacific Power Company (SPPCo) at their Tracy Station in Nevada is one of three IGCC facilities being cost-shared by the U.S. Department of Energy (DOE) under their Clean Coal Technology Program. The specific technology to be demonstrated in SPPCo's Round Four Project, known as the Piñon Pine IGCC Project, includes the KRW air blown pressurized fluidized bed gasification process with hot gas cleanup coupled with a combined cycle facility based on a new GE 6FA gas turbine. Construction of the 100 MW IGCC facility began in February 1995 and the first firing of the gas turbine occurred as scheduled on August 15, 1996 with natural gas. Mechanical completion of the gasifier and other outstanding work is due in January 1997. Following the startup of the plant, the project will enter a 42 month operating and testing period during which low sulfur western and high sulfur eastern or midwestern coals will be processed.

Acknowledgements

The following are acknowledged for their ongoing, valuable support to SPPCo on this project: Douglas M. Jewell of Morgantown Energy Technology Center, who has been the DOE Project Manager since the project began with the signing of the Cooperative Agreement in August

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1992; Foster Wheeler USA Corporation (FWUSA) of Clinton, New Jersey, subcontractor to SPPCo for project management, engineering, and construction management for the overall facility; and The M W Kellogg Company of Houston, Texas, subcontractor to FWUSA for design engineering, equipment procurement, and other services for the coal gasification section of the plant.

Introduction

The Piñon Pine Power Project was one of the successful proposals in response to the U.S. Department of Energy's (DOE) Clean Coal Technology, Round Four solicitation which invited submissions for cost-shared projects to demonstrate technologies capable of replacing, retrofitting or repowering existing coal based facilities. The Program Opportunity Notice (PON) for the fourth round called for projects to demonstrate innovative, clean and energy efficient technologies with particular emphasis on achieving significant reduction in emissions of sulfur dioxide and/or nitrogen oxides from existing facilities and/or providing for future energy needs in an environmentally acceptable manner.

In the Piñon Pine IGCC Project, Sierra Pacific Power Co., (SPPCo) aims to demonstrate the use of advanced coal technologies to produce clean and low cost power to meet their growing customer needs. The facility is being built at SPPCo's Tracy Station some 20 miles east of Reno, Nevada and includes the design, engineering, procurement, construction and testing of a nominal 100 MW coal fueled integrated gasification combined cycle (IGCC) plant. The KRW air blown pressurized fluidized bed coal gasifier with hot gas cleanup will produce high temperature coal gas to be burned in a GE frame 6FA combustion turbine to generate about 60% of the plant power output. The rest of the power will be produced in a steam turbine generator driven by steam produced primarily from the combustion turbine exhaust gases. Foster Wheeler USA Corporation (FWUSA) is providing the design, engineering, procurement, and construction management of the overall facility with The M W Kellogg Company (MWK) subcontracted to supply the design, engineering, equipment procurement, and other services relating to the gasification island.

The GE Frame 6FA combustion turbine at the Piñon Pine Project is the first of its kind in the world and was successfully fired for the first time on August 15, 1996 using natural gas. The combined cycle part of the plant began commercial operation on natural gas in November 1996. Work is proceeding to complete the coal gasification island and support facilities in January 1997. The operation and testing phase of the project will last for 42 months and will include operation with the design coal, Southern Utah bituminous, as well as tests on high sulfur eastern or midwestern coal. The cost of building, commissioning and demonstrating the overall facility will be about $335 million to be shared equally between DOE and SPPCo.

Project Goals

First and foremost in SPPCo's decision to proceed with the project was the objective to generate low cost, base load power using coal in a clean environmentally acceptable manner.

To this end the aims of the Piñon Pine Power Project include:

- Demonstrating air blown, pressurized fluidized bed IGCC technology incorporating hot gas cleanup.
- Evaluating a combustion turbine firing low Btu coal gas.
- Assessing efficiency and the long term reliability, maintainability and environmental performance of the complete facility.
- Providing SPPCo with increased fuel flexibility in their generation system.

At the average ambient conditions for the Reno area, the plant is expected to perform in accordance with Table 1.

TABLE 1

Coal Feed (T/D)	880.6
Gas Turbine Power (Mwe)	60.99
Steam Turbine Power (Mwe)	46.23
Gross Power (Mwe)	107.22
Auxiliary Power (Mwe)	7.51
Net Power (Mwe)	99.71
Net Heat Rate (Btu (LHV)/kWh)	8096
Net Heat Rate (Btu (HHV)/kWh)	8390
Thermal Efficiency (LHV)%	42.1
Thermal Efficiency (HHV)%	40.6

Key Technology Features

The KRW process (licensed by The M W Kellogg Technology Company) to produce clean high temperature coal gas improves upon the first generation IGCC technologies in several aspects which can be summarized as follows:

- Air Blown Gasification

  Using air in place of oxygen as the oxidant in the gasification process leads to a simpler plant configuration and lower capital cost. In the air blown process 15 to 20% of the gas turbine compressor air is extracted for use as oxidant in the gasifier.

  The gasifier is capable of operating with a wide variety of coals. This fuel flexibility is a major advantage of the process. During the testing period the design coal, a low sulfur western U.S. coal , will be the predominant fuel with campaign test runs of eastern or midwestern high sulfur coal.

Addition of limestone (or dolomite) to the gasifier serves several purposes. Dolomite offers economic, as well as processing, advantages for sulfation and ultimate ash disposal. Limestone (or dolomite) captures a large percentage of the sulfur released from the coal in the gasification process. Furthermore, previous test work indicates that the presence of limestone reduces the amount of ammonia produced, the latter being a contributor to NO_x generation in the gas turbine combustor.

- Hot Gas Particulate Removal

Filtering of the gas at high temperature enables the sensible heat to be maintained resulting in higher plant efficiency.

- Hot Gas Desulfurization

Sulfur contained in the coal is removed in two steps. Some of the hydrogen sulfide produced in the reducing environment of the gasifier is captured as calcium sulfide by limestone fed to the gasifer with the coal. Chemical equilibrium considerations limit the capture to about 50% with low sulfur coal, but with high sulfur coals this can approach 90%. Sulfur, primarily in the form of hydrogen sulfide not captured by the limestone or retained by the ash exits the gasifier in the product gas steam, and is removed by the zinc based sorbent in the external hot gas transport desulfurization system.

- Sulfation

Coal ash with spent limestone (LASH) containing calcium sulfide and unconverted carbon is treated in the sulfator system which oxidizes the sulfide to calcium sulfate, combusts unconverted carbon and absorbs sulfur dioxide from the external transport desulfurization system regeneration gas.

Plant Configuration

Block flow diagram **Figure 1**, indicates the main parts of this IGCC facility. Crushed coal ¼" x 0 and limestone (or dolomite) 16 x 200 mesh are pneumatically fed via lock hoppers into the gasifier, along with additional air from the booster compressor, through the concentric central

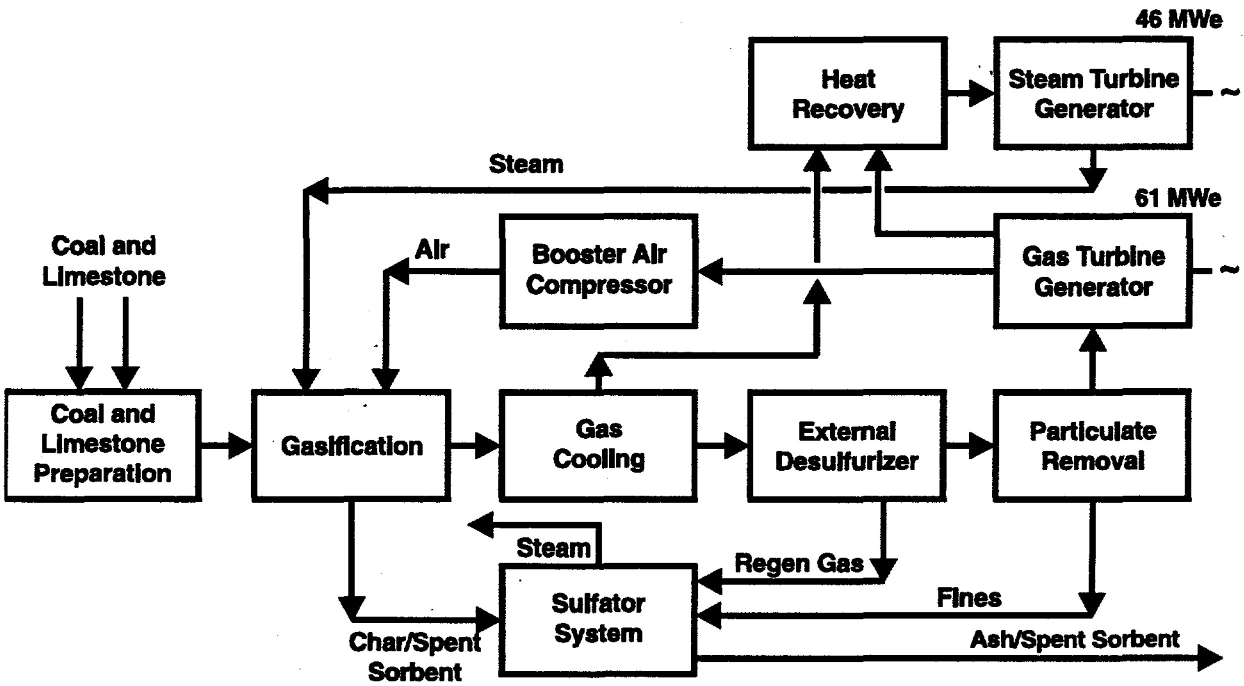

Figure 1: Block Flow Diagram

feed tube forming a high velocity jet (See **Figure 2**). Once in the gasifier the coal is quickly devolatilized. Partial combustion of char and gas occurring within the jet provides the heat necessary for the endothermic devolatilization, gasification, and desulfurization reactions. Extraction steam from the steam turbine is injected through the gasifier grid to aid in fluidization and drive the gasification reactions. LASH particles which separate from the bed particles due to their higher density are cooled and removed from the bottom of the gasifier. Recycle gas is used for fluidization and for cooling the LASH. The coal gas leaving the top of the gasifier contains significant quantities of entrained solids consisting of char, ash, and sorbent. A cyclone removes most of the entrained solids which are returned to the gasifier bed via the dipleg. The product gas is cooled from about 1800°F to 1000°F in a series of exchangers with the heat recovered as high pressure steam. The cooled coal gas is treated in the hot gas cleanup system to meet the specification required for fuel to the combustion turbine.

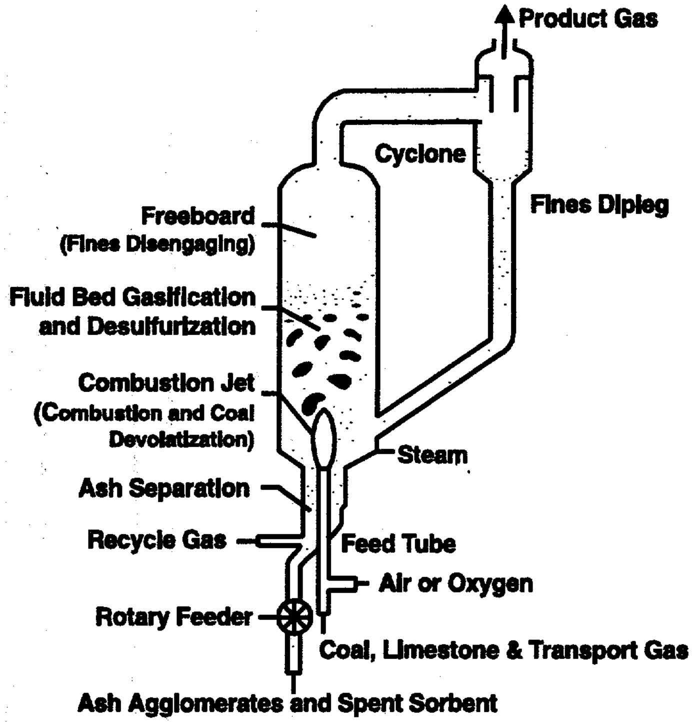

Figure 2: KRW Gasifier

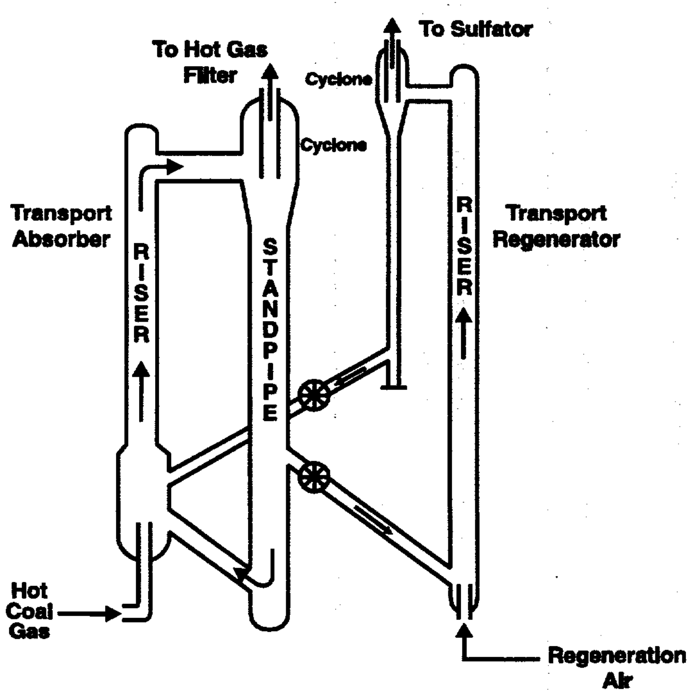

Figure 3: Transport Desulfurizer

In the transport desulfurizer system shown in **Figure 3**, a zinc oxide based sorbent which also contains nickel oxide reduces the sulfur content in the gas to less than 20 ppmv. Fuel gas enters the mixing zone at the bottom of the transport absorber riser where it mixes with the sorbent recirculated from the absorber cyclone. Absorption of the gaseous sulfur compounds occurs in the riser section as the fuel gas and sorbent flow upward into the absorber cyclone. A slip stream of sulfurized sorbent is withdrawn from the absorber standpipe and enters the bottom of the transport regenerator along with preheated air. The sulfur rich gas exits the transport regenerator at about 1400°F and flows to the sulfator. Regenerated sorbent is returned to the absorber by a controlled gravity flow.

Particulates are removed from the hot desulfurized gas in a Westinghouse ceramic candle filter system before the product gas is burned in the combustion turbine. Filter fines are burned in the fines combustor in the sulfator system.

With the exception of a very small quantity of sulfur in the fuel gas to the gas turbine (about 20 ppmv) all the sulfur in the coal is ultimately disposed of in the sulfator system which includes an air fluidized bubbling bed reactor. The sulfator is operated at about 1600°F to maximize capture of the sulfur dioxide released from combustion of residual char in the LASH and that contained in the transport regenerator effluent gas. This high temperature also maximizes oxidation of the calcium sulfide to the sulfate form. Sulfator off gas is used to quench the fines combustor effluent stream which is vented through a baghouse after cooling the gas by raising additional steam. Sulfator solids are cooled, combined with fines from the baghouse, and stored in a silo for intermittent transfer by truck to landfill or for other uses.

The GE model 6FA gas turbine forms the heart of the power island. The technologically advanced firing temperature (2350°F) and cooling system of the F-Class machines provide such units operating in combined cycle configuration with the highest total cycle efficiencies of any proven type of fossil fueled electric power generation system. Mechanical power will be converted to electrical power in a once through air cooled synchronous generator which will provide 61 MW of power.

Thermal energy in the exhaust gases from the combustion turbine is captured in a heat recovery steam generator (HRSG), the steam from which will drive a condensing steam turbine generator to produce an additional 46 MW of power. In-plant power use is expected to be only 7 MW which is less than oxygen blown IGCC processes due to the lack of a requirement for an air separation unit.

Technology Development

The Piñon Pine IGCC project integrates a number of technologies fostered by the DOE over a period of many years. These include the KRW gasifer with in-bed desulfurization using limestone, external hot gas desulfurization and hot gas particulate removal.

The DOE and its predecessors supported the KRW gasifer development from 1972 to 1988. Westinghouse Electric Corporation originally proposed the technology and in 1975 completed the construction at Waltz Mill, Pennsylvania of a 25 ton/day Process Development Unit (PDU). Testing proceeded for more than a decade thereafter. In 1986, The M W Kellogg Company acquired the process. The PDU was operated in the air and oxygen blown modes and tested many different types of coal from many parts of the world ranging from lignite to anthracite. Tests also included in-bed desulfurization using limestone and dolomite sorbents, the use of ceramic (and sintered metal) filters for particulate removal and external-bed desulfurization using zinc ferrite in a fixed bed reactor.

Based on experience at Waltz Mill the initial process design for the Piñon Pine Power Project included a fixed bed hot gas desulfurization system using zinc ferrite sorbent. In support of this project following its selection under Round 4 of the Clean Coal Program, DOE at their Morgantown Energy Technology Center tested zinc ferrite, zinc titanate, and Z-Sorb®, developed by Phillips Petroleum Company. From these screening tests Z-Sorb® proved to have the best properties. These tests also strongly indicated economic and technical reasons for not using a fixed bed system. A transport type system was then evaluated by MWK.

After a series of tests and a detailed technical review of both fixed bed and transport systems, the latter was chosen for demonstration in the SPPCo project. The transport system represents both a technical and cost improvement over the fixed bed arrangement. The inventory of sorbent is greatly reduced and the overall system is much simpler with no cycling valves in hot product gas streams, and no opportunity for process upsets during bed switching which could occur with the multi-vessel fixed bed system.

Project Schedule

The project schedule is shown in **Figure 4**. The Cooperative Agreement was signed in August 1992, which signaled the commencement of phased execution of the project. With the design phase completed, the construction and startup phase started in January 1995. The first firing of the combustion turbine was successfully carried out as scheduled on August 15, 1996 using natural gas. Mechanical completion of the combined cycle power plant section of the project was achieved on August 29, 1996. Work is proceeding to complete commissioning of the gasifier island and supporting balance of plant in January 1997 with the commencement of Phase 3, operation and testing in February 1997.

Future Plans

The 42 month Phase 3 of the Piñon Pine IGCC Project will include extensive tests of process, equipment, and controls using the design coal, (Southern Utah low sulfur bituminous), as well as a specific campaign on midwestern or eastern high sulfur coal.

Key aspects of the facility that will be demonstrated include the air blown KRW gasifier with in-bed desulfurization, the hot gas transport desulfurization system and the high temperature ceramic candle filter system, as well as the GE Model MS6001FA gas turbine operating with low Btu coal gas and natural gas (and the ability to switch from one to the other), and the capability of the facility as a whole to operate in base load mode and follow load demand variations in accordance with utility standard requirements. In addition the facility will demonstrate that it complies with acceptable emissions and with the required efficiency, reliability, availability, and maintainability.

Successful demonstration of this technology will provide the power generation industry with design, construction and operating information for assessing new power generation options. The performance of the KRW-based IGCC technology together with its modular design concept will offer an attractive way to satisfy future demand for greenfield electricity generating facilities. In addition, with the large number of existing boilers reaching the end of their useful lives, the air

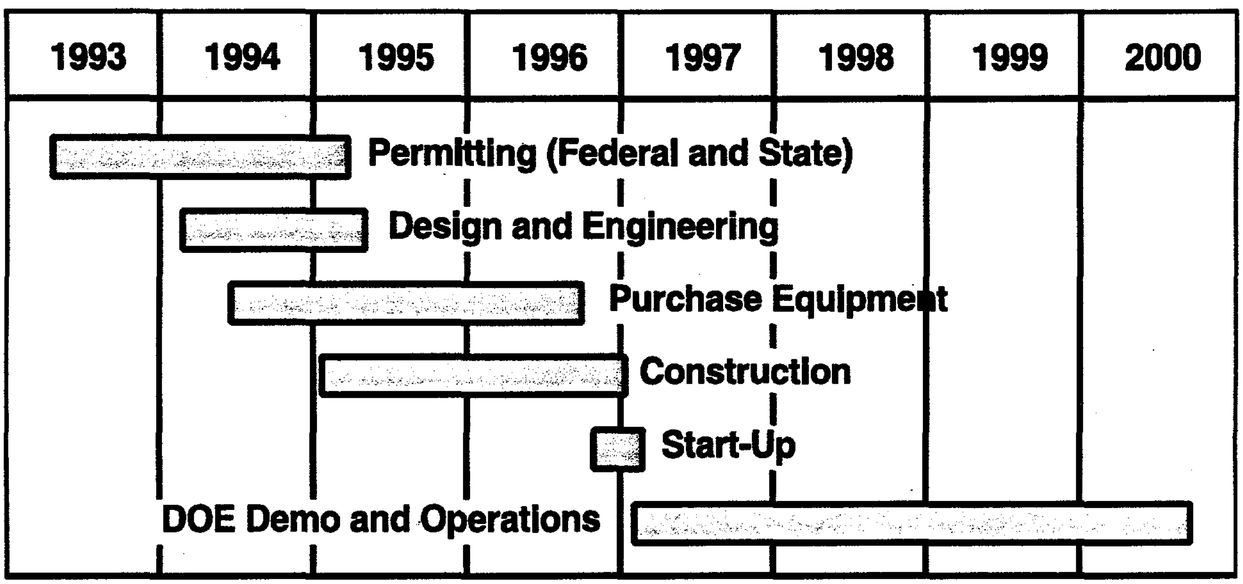

Figure 4: Schedule of Piñon Pine Project

blown KRW based IGCC process with its relatively simple configuration and limited space requirement offers an excellent method to repower these stations. The resulting facility could produce up to three times the power currently generated by the existing steam turbine.

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McIntosh Unit 4 PCFB Demonstration Project

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Introduction

The City of Lakeland, Foster Wheeler Corporation and Westinghouse Electric Corporation have embarked on a utility scale demonstration of Pressurized Circulating Fluidized Bed (PCFB) technology at Lakeland's McIntosh Power Station in Lakeland, Florida. The U.S. Department of Energy will be providing approximately $195 million of funding for the project through two Cooperative Agreements under the auspices of the Clean Coal Technology Program. The project will involve the commercial demonstration of FOSTER WHEELER PYROFLOW PCFB technology integrated with Westinghouse's Hot Gas Filter (HGF) and power generation ® technologies.

The total project duration will be approximately eight years and will be structured into three separate phases; two years of design and permitting, followed by an initial period of two years of fabrication and construction and concluding with a four year demonstration (commercial operation) period. It is expected that the project will show that Foster Wheeler's Pyroflow PCFB technology coupled with Westinghouse's HGF and power generation technologies represents a cost effective, high efficiency, low emissions means of adding greenfield generation capacity and that this same technology is also well suited for repowering applications.

Background

The City of Lakeland, Department of Electric & Water Utilities (Lakeland) is a municipally owned and operated electric and water utility in Central Florida. Lakeland is conveniently located between Tampa and Orlando which has allowed Lakeland to grow and prosper over its 92 year history. Lakeland is the third largest municipal utility in the State of Florida serving more than 104,000 electric customers and also has residential rates that are currently the second lowest of all Florida utilities. Despite enjoying low electric rates and steady load growth, Lakeland is not immune to competition. Competition is driving all utilities to find ways not only to prevent cost growth but to also lower costs. A heightened awareness of the environment by the general public and Lakeland's customers is also maintaining the pressure for "clean" electric generation. Traditionally these two goals have not been complimentary in that environmental compliance normally has meant an increase in generation costs to achieve that compliance. This raises the question each utility must soon face: how to provide new generating capacity, needed for growth and replacement of retired capacity, at a competitive cost while meeting stringent environmental requirements.

Lakeland has experienced and is forecasting steady load growth within its municipal system of approximately 15 MW per year which will result in a capacity shortfall in the year 2000 of approximately 45 MW. In addition to the pending capacity shortfall, Lakeland wishes to retire 50 MW of very old and inefficient existing generating capacity. Considering both of these issues and future needs, Lakeland needs to bring on line at least 150 MW of additional generating capacity by the year 2000.

In today's competitive environment, the prospects of adding additional capacity in itself can bring many uncertainties. With the majority of Lakeland's capacity already tied to one fuel that has greater uncertainties in such areas as price and availability, the need to add more capacity led Lakeland to look closely once again at America's most abundant fuel source, coal. Lakeland's current mix of resources include approximately 200 MW of base load pulverized coal and 450 MW of intermediate/peaking gas capacity. This capacity is divided between two power stations that Lakeland owns which are located within the city limits on the shores of Lake Parker. The larger of the two power stations is the McIntosh station on the north side of Lake Parker with approximately 590 MW of generating capacity while the smaller Larsen station on the south side of the lake has about 230 MW of [1]generating capacity.

Lakeland was a pioneer of sorts when the 334 MW McIntosh 3 unit went on-line in 1982. The unit was one of the first "scrubbed", zero-discharge coal units in the nation. Today, Lakeland is looking to be a pioneer again by partnering with Foster Wheeler Corporation and Westinghouse Electric Corporation to build and operate a utility scale demonstration of PCFB technology (unit 4) at Lakeland's McIntosh Plant site. The addition of McIntosh unit 4 will provide Lakeland with new, cost competitive and environmentally clean coal based capacity for the 21st Century. The added capacity that this unit will provide will not only add to Lakeland's fuel diversity, but will provide energy at some of the lowest costs per megawatt hour of any generating source in the Southeast. These factors combined with the state of the art pollution controls provided by the Foster Wheeler PCFB process and the Westinghouse HGF technology will ensure that McIntosh unit 4 will keep Lakeland very competitive and environmentally acceptable well into the future.

The successful construction and operation of this technology will provide utilities with a means of adding needed generating capacity in a manner that is consistent with the competitive and environmental challenges that all are facing.

[1]McIntosh Unit 3 is a 334 MW pulverized coal unit that is jointly owned by Lakeland and the Orlando [1]Utilities Commission.

Project Structure

The proposed McIntosh Unit 4 PCFB Demonstration Project would be constructed as two sequential demonstrations that would demonstrate both PCFB and Topped PCFB technology. There are two primary reasons for this proposed project structure:

(I) The DOE funding being provided for the project results from a combination of two previous Clean Coal awards: the DMEC-1 PCFB Repowering Project (DMEC-1) selected under Round III and the Four Rivers Energy Modernization Project (FREMP) selected under Round V. The DMEC-1 project was intended to demonstrate PCFB technology while the FREMP project was planning to demonstrate Topped PCFB technology. By utilizing a sequential approach with the McIntosh Unit 4 PCFB project, it will be possible to demonstrate both PCFB (1st Demonstration) and Topped PCFB (2nd Demonstration) technology in the same project, thereby satisfying the objectives of both the DMEC and FREMP projects.

(II) Additional development work is required on certain components of the Topped PCFB cycle prior to the construction of the same components at a commercial scale. Specifically, additional development is required for the Westinghouse topping combustor (multi-annular-swirl-burner or MASB) including the demonstration of MASB operation at low outlet oxygen levels. Important aspects of Westinghouse's MASB development work have been and will be conducted at the University of Tennessee Space Institute. Some additional development work may also be performed for other components of the carbonizer system. Development on the carbonizer system has been performed at Foster Wheeler's John Blizzard Research Center in Livingston, New Jersey. Both of these systems are incorporated in the Wilsonville Power Systems Development Facility (PSDF) facility at a Southern Company operated site in Wilsonville, Alabama that will shortly be starting operation. The combination of the above programs is expected to provide Westinghouse and Foster Wheeler with the necessary information required to finalize the design of the carbonizer and MASB's in time to support the demonstration of Topped PCFB technology.

The project schedule (discussed in more detail below) anticipates the start of commercial operation of the 1st Demonstration in the winter of the year 2000. In parallel with the first two years of operation of the 1st Demonstration will be the design, fabrication and construction of the 2nd Demonstration culminating in a planned start of operation of late 2002 for the combined facility.

Project Objectives

Through the sequential demonstration of both PCFB and Topped PCFB technology it has been possible to preserve the objectives of both the original Cooperative Agreements described in the preceding section. The objectives governing the agreement relating to PCFB technology include the demonstration of PCFB technology to provide for the potential commercialization of the technology in the 21st century and to provide the capability of achieving significant reductions in the emissions of sulfur oxide and nitrogen oxides from existing facilities when they are repowered with PCFB technology.

The objectives for the agreement relating to Topped PCFB technology call for the demonstration of the technology in a "fully commercial power generation setting" which is certainly the case at the McIntosh site as is further explained below. All the key components of the Topped PCFB technology will be demonstrated thereby paving the way for future plants that will operate at higher gas turbine inlet temperatures and that are expected to provide cycle efficiencies in excess of 45%. Additional objectives relating to the Topped PCFB technology that will be proven through a successful demonstration include reductions in sulfur oxide emissions of as much as 95% and nitrogen oxide emissions as low as 0.17 lb/MMBTU of heat input.

Process Description

PCFB technology is a combined cycle power generation system that is based on the pressurized combustion of solid fuel to generate steam in a conventional Rankine cycle combined with the expansion of hot pressurized flue gas through a gas turbine in a Brayton cycle. The technology can be subdivided into the basic PCFB cycle ("First Generation") and Topped PCFB cycle ("2nd Generation" or "Advanced PCFB"). In the PCFB cycle, hot pressurized flue gas is expanded through the gas turbine at a temperature of less than 1650°F. Topped PCFB cycles include a coal carbonizer (mild gasifier) to generate a low BTU fuel gas which is used to fire the inlet of the gas turbine (in a topping combustor or MASB) and increase the gas turbine inlet temperature from a less than 1650°F up to 1900° - 2300°F or higher. Both versions of PCFB technology offer high cycle efficiencies and ultra low emissions. More detailed descriptions of the PCFB and Topped PCFB cycles are provided below.

Figure 1 presents a simplified schematic of the 1st Demonstration of the McIntosh Unit 4 PCFB Demonstration Project incorporating a PCFB cycle. Combustion air is supplied from the compressor section of the gas turbine to the PCFB combustor located inside a pressure vessel.

Coal and limestone are mixed with water into a paste which is pumped into the combustion chamber using piston pumps commonly used in the concrete industry. The same type of pumps have been successfully proven in a number of pressurized fluidized bed combustion (PFBC) coal projects around the world.

Combustion takes place at a temperature of approximately 1560° - 1600°F and at a pressure of about 200 psig. The resulting flue gas and fly ash leaving the cyclone enter the hot gas filters where dust removal takes place. The hot gas filters are a Westinghouse design based closely on the filter supplied to the Sierra Pacific Piñon Pine project in Tracy, Nevada. In addition to the Piñon Pine project, a Westinghouse filter has undergone approximately 6000 hours of testing at Ohio Power's Tidd PFBC Demonstration facility in Brilliant, Ohio (Round I project). A full scale commercial module of this type of ceramic candle filter has also undergone more than 6000 hours of extensive testing at Foster Wheeler's PCFB test facility in Karhula, Finland.

The hot clean gas leaving the filter is expanded through the gas turbine before passing through a heat recovery unit and entering the stack. Heat recovered from the cycle from both the combustor and the heat recovery unit is used to generate steam to power a reheat steam turbine. Approximately 15% of the gross power output is derived from the gas turbine with the steam turbine contributing the remaining 85%.

The gas turbine technology is based on a standard Westinghouse 251B12, single shaft, cold end drive industrial machine that has had the center section of the turbine modified. A scroll section has been added to allow for the removal of compressor discharge air from the casing for external firing in the PCFB combustor and to allow for the introduction of hot clean gas back through the casing into the expander section. This air outlet/gas inlet configuration has been previously applied in recuperative gas turbine cycles. The gas inlet temperature of less than 1650 F allows for a simplified turbine shaft and blade cooling system. This combined with low excess air operation in the PCFB combustor provides a maximum amount of steam generation per unit mass of air from the gas turbine and therefore maximizes power output from the cycle.

Figure 2 shows the process flow arrangement of the 2nd Demonstration of the McIntosh Unit 4 PCFB Demonstration Project. This involves the addition of a carbonizer island which includes a topping combustor (MASB) to convert the PCFB cycle to a Topped PCFB cycle. Through the addition of this equipment, the inlet temperature to the gas turbine is increased via the combustion of coal derived "syngas". This has the effect of increasing the cycle power output while simultaneously improving the net plant heat rate. Natural gas can also be used as the topping fuel thereby providing a backup to the operation of the carbonizer island.

In the top right hand corner of Figure 2, the carbonizer island is shown. Dried coal and limestone are fed via a lock hopper system to the carbonizer together with part of the gas turbine compressor discharge air. The coal is partially gasified or carbonized at about 1700°F to produce a syngas and char solids stream. The limestone is used to absorb sulfur compounds generated during the mild gasification process and to catalyze the gasification process. After cooling the syngas to about 1200°F, the char and limestone entrained with the syngas are removed by a Westinghouse hot gas filter. The char and limestone are transferred to the PCFB combustor for complete carbon combustion and limestone utilization. The hot clean filtered syngas is then fired in a topping combustor (MASB) to raise the turbine inlet temperature to almost 2000°F. The gas is expanded through the turbine, cooled in a heat recovery unit and exhausted to the stack. As in the case of the previous cycle, combustion air is supplied to the PCFB combustor from the compressor section of the gas turbine. Coal and limestone are again fed to the PCFB combustor in paste form but are supplemented by the char transferred from the carbonizer as discussed above.

Performance

The First Demonstration would involve a basic PCFB cycle that would come on line in the year 2000 and would provide approximately 157 MW of coal-fired generating capacity. The cycle would have a gas turbine inlet temperature of approximately 1550°F. Following the completion of some additional development work, the Second Demonstration of the project would be constructed and brought on line approximately two years later. This would entail the conversion of the 1st Demonstration PCFB system to a Topped PCFB system through the addition of a carbonizer island and a topping combustor. The addition of the carbonizer system would generate a coal derived, low BTU synthesis gas that would be fired at the inlet of the gas turbine to raise the turbine inlet temperature to approximately 1975°F. The net impact of this equipment addition would be an additional 12 MW of power output with an associated improvement in heat rate of about 600 BTU/kWhr for the entire plant.

The project would be constructed as McIntosh Unit 4 within the boundaries of existing station on land owned by the city. The new unit will be designed to burn a range of coals including both the current Eastern Kentucky coal burned in unit 3 and high ash, high sulfur coals that are expected to be available in the future at substantially lower prices than mid to low sulfur bituminous coals. Limestone would be sourced from a number of nearby Florida limestone quarries while ash would be disposed of in a landfill or marketed to others.

The majority of the project's water makeup requirements will be met using secondary treated sewage effluent for cooling tower makeup while the use of sewage "sludge" (3 - 4% solids) is being considered for preparation of the coal-water paste mixture that is pumped into the PCFB. Service water will be used only for boiler water makeup feed to the demineralizer system. Wastewater from the unit will be treated on site for neutralization and removal of heavy metals before being returned to the Glendale waste water treatment facility (owned by Lakeland) for discharge. Gaseous emissions from the plant will be controlled using state of the art technology and will be representative of recent best available control technology (BACT) determinations in Florida.

Project Schedule

The City of Lakeland wishes to have the 1st Demonstration plant enter commercial operation during the winter of the year 2000. Prior to commencing fabrication and construction (Phase 2) of the new facility, the permitting and licensing process required by the state of Florida must be completed. In addition, DOE requires that the National Environmental Policy Act (NEPA) process be completed prior to DOE providing any funds for the purpose of fabricating and constructing the facility.

The NEPA and permitting/licensing processes are each expected to take 20 months to complete and are parallel critical path activities dictating the duration of Phase 1 of the project. At the time of writing, Phase 1 was expected to begin around December 1, 1996 following the formal execution of the Cooperative Agreements by Lakeland and DOE. Phase 2 begins with the general release for fabrication and construction for the 1st Demonstration and lasts for a total of 53 months. Phase 3 has an overall duration of 48 months. The first 29 months of Phase 2 cover the period from the end of Phase 1 through to the start of Phase 3 during which the 1st Demonstration facility is fabricated and constructed. The second 24 months of Phase 2 overlap with Phase 3 and cover the time required to design, engineer, fabricate and construct the 2nd Demonstration equipment.

Phase 3 will be structured in two segments: an initial two year period while the PCFB technology of the 1st Demonstration is demonstrated, and a subsequent two year period during which the Topped PCFB technology of the 2nd Demonstration will be operated. The additional equipment required for the 2nd Demonstration will be engineered, procured and constructed in parallel with the operation of the 1st Demonstration during the first two years of Phase 3. All efforts will be made to minimize the amount of downtime of the facility required to connect the 2nd Demonstration equipment to the 1st Demonstration plant.

Figure 3 presents an overview of the anticipated project schedule.

Project Cost and Funding Summary

The total cost and funding summaries for McIntosh Unit 4 PCFB Demonstration Project in "as spent" dollars are shown below. The total project costs include the total cost to construct the facility, certain project related offsite costs, 4 years of operation and maintenance (O&M) costs, owner's costs and permitting costs.

($1000)
COSTS Total Project Costs 387,970
Lakeland In-Kinds 2,030
TOTAL COSTS 390,000
FUNDS Lakeland In-Kinds 2,030
Lakeland 192,970
DOE 195,000
TOTAL FUNDS 390,000

The total McIntosh Unit 4 PCFB Demonstration project costs have been divided between the two Cooperative Agreements.

Participant Project Financing

The City of Lakeland has a number of financing alternatives to use for the project. Lakeland has accumulated reserves for future expansion and system general purpose uses. These funds are available for use by the City's Department of Electric & Water Utilities and part of them have been earmarked for the McIntosh Unit 4 PCFB Demonstration Project.

Lakeland also enjoys very favorable bond ratings due to its long-standing financial health. Recently, the drop in interest rates was found to be financially favorable for Lakeland's financing team to issue tax exempt revenue bonds in order to provide funding for several projects listed in Lakeland's current capital forecast. As with any bond issue, this issue has been rated by the bond rating agencies. Lakeland had the bonds rated by Standard and Poor's Group (AA-) and Moody's Investors Service, Inc. (Aa). Lakeland has maintained these ratings since 1989 when the Moody's rating was upgraded to the current level.

The payments for operating costs of Lakeland's Department of Electric & Water Utilities are funded through revenue generated by the sale of electricity and water. The amount of revenue is in part determined by the rates charged for these products. The Department of Electric & Water Utilities, through its long range forecasts, identifies when rate increases are expected. These are identified years in advance of the actual need and are then implemented when, and at the level necessary to continue the financially sound operations of Lakeland. The City Commission for the City of Lakeland has the rate making authority for the Department of Electric & Water Utilities.

Detail revenue and expense budgets are prepared and reviewed each year. The approved budgets are then used to update the long range forecast to determine their impact on future years. This process has been very successful for Lakeland in avoiding unplanned rate increases. In fact, since 1989, Lakeland has been able to implement lower rate increases than originally forecast. Lakeland also believes that the Pressurized Circulating Fluidized Bed generator that this project will involve will operate more efficiently than any of its current generators, further strengthening Lakeland's financial position, and aiding it in providing cost effective power to its customers. The revenue anticipated from operating the new generator is based on the expected demand from existing customers and is not contingent on any future negotiations or sales to another utility.

Project Organization

The City of Lakeland is anticipating entering into an engineer, procure, construct (EPC) contract with a Foster Wheeler/Westinghouse consortium for the entire McIntosh Unit 4 PCFB project with the exception of certain specific items such as a 90 car unit train that would be handled by Lakeland's staff. Through the execution of a single EPC contract, Lakeland would have a single point of contact and single point of responsibility for all issues associated with the project. In order to assist Lakeland in reviewing and monitoring the performance of the EPC contractor, Lakeland is in the process of entering into an additional contract with a company who will act as the "Owner's Engineer". This company will safeguard Lakeland's interest on the project and conduct an ongoing prudency review.

In order to obtain the required permits and licenses for the construction and operation of McIntosh Unit 4, the City of Lakeland has retained the services of a qualified environmental consulting firm with particular expertise in the state of Florida. This same firm will be empowered to prepare the necessary information required by DOE to complete the NEPA process and is expected to liaise closely with DOE's chosen NEPA consultant or subcontractor.

Project Status

At the time this paper was written, DOE had recently announced approval of the project and efforts were underway to have all the Cooperative Agreements and related project agreements formally executed by the parties. Completion of this activity will trigger the formal start of Phase 1 of the McIntosh Unit 4 project. In parallel with this activity, the scope of work of each of the project participants, and their role within the project structure, is currently being fine tuned and finalized. The agreements necessary for each project participant to fulfil their project obligations are in the process of being negotiated. Two important project activities that will be initiated shortly are the permitting and NEPA activities.

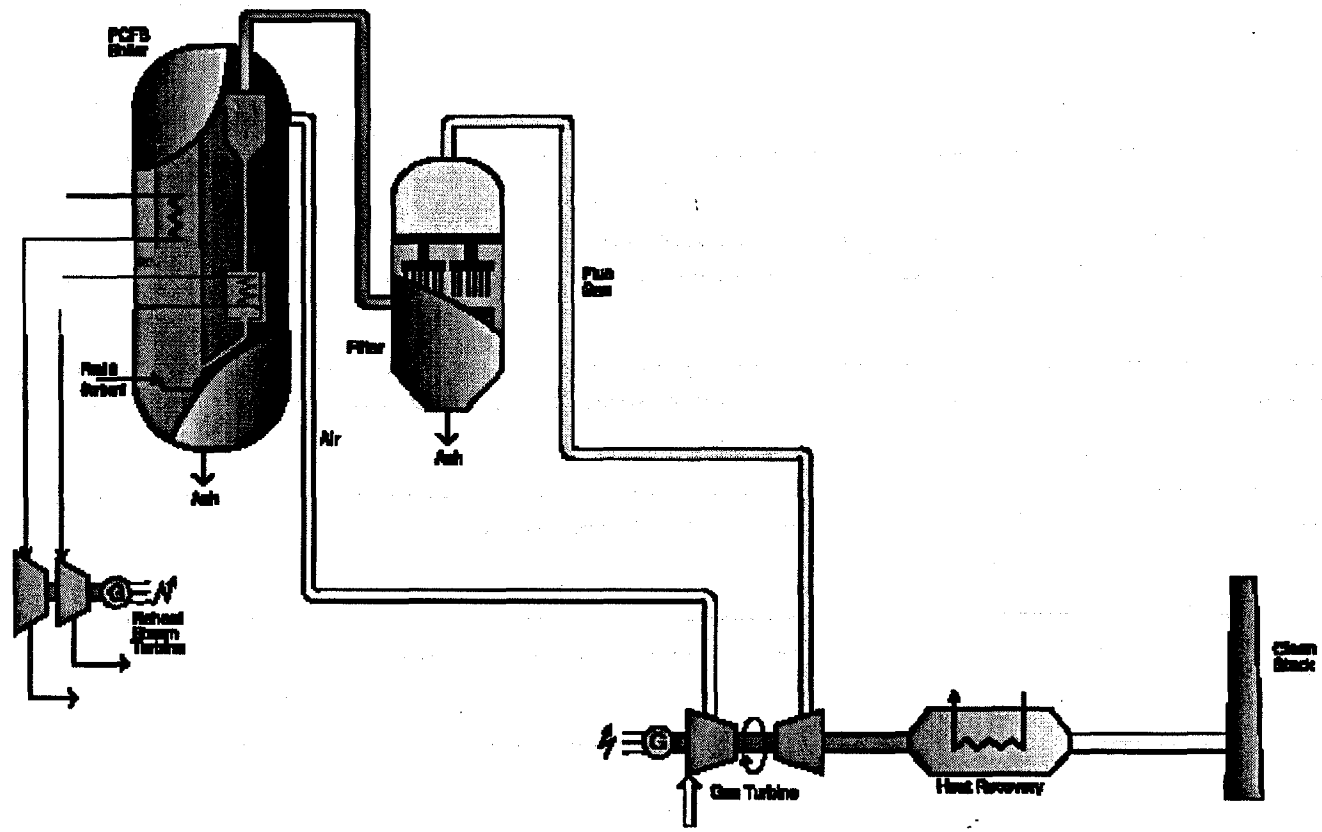


Figure 1.
PCFB Cycle - 1st Demonstration

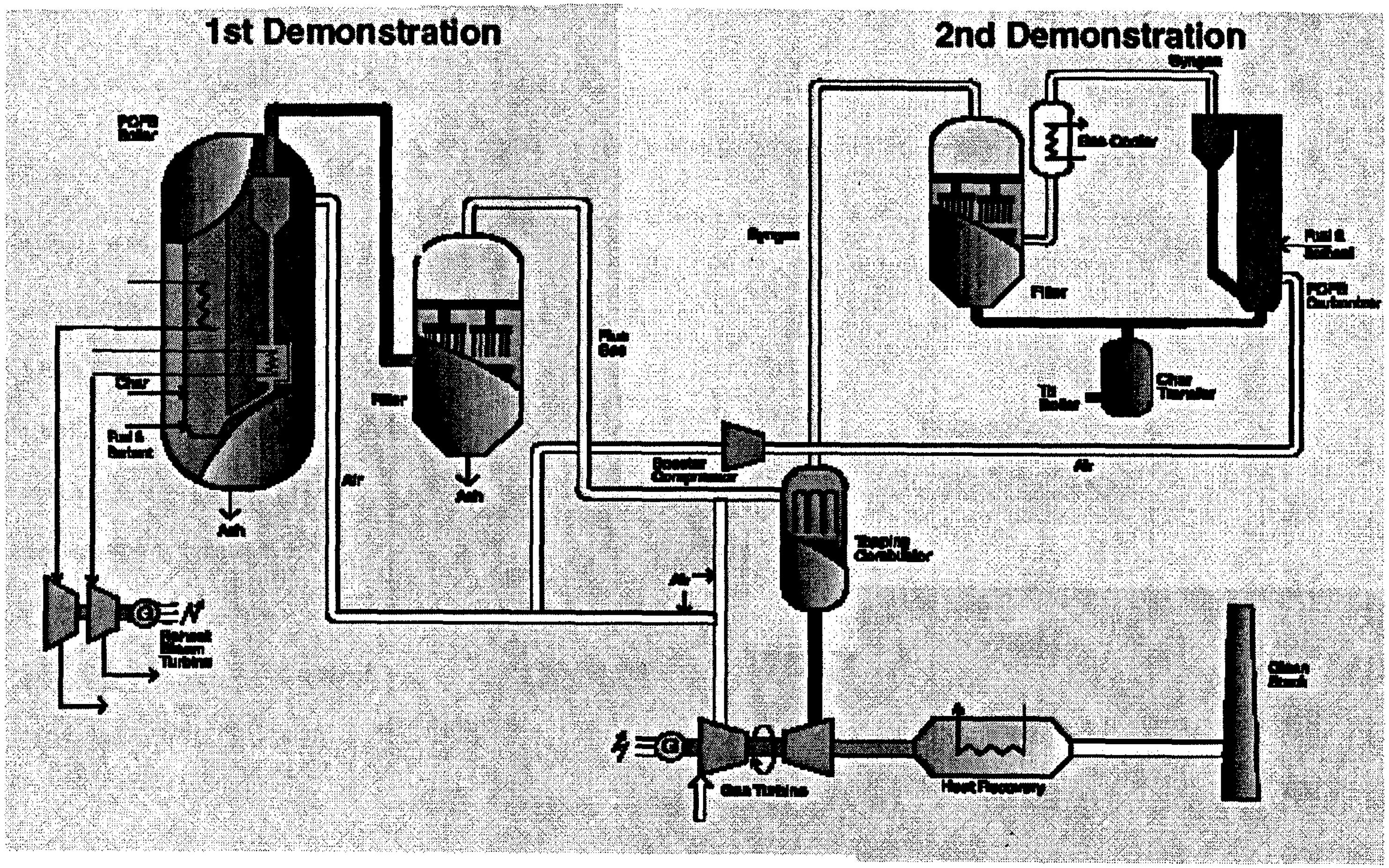
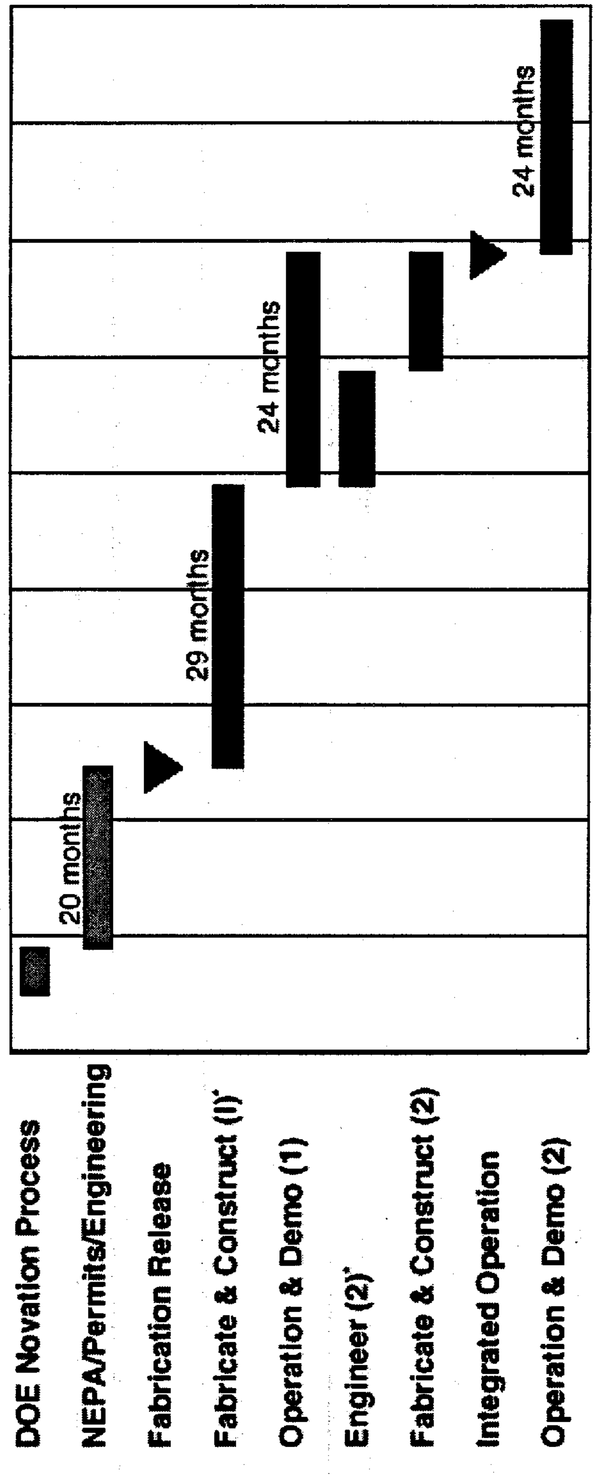


Figure 2
Topping PCFB Cycle - 2nd Demonstration

Figure 3
McIntosh Unit 4 Summary Schedule



* (1) refers to 1st Demonstration and (2) to 2nd Demonstration

Poster Session Abstracts

THE HEALY CLEAN COAL PROJECT
AN OVERVIEW

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ABSTRACT

The Healy Clean Coal Project, selected by the U.S. Department of Energy under Round III of the Clean Coal Technology Program is currently in construction. The project is owned and financed by the Alaska Industrial Development and Export Authority (AIDEA), and is cofunded by the U.S. Department of Energy. Construction is scheduled to be completed in August of 1997, with startup activity concluding in December of 1997. Demonstration, testing and reporting of the results will take place in 1998, followed by commercial operation of the facility. The emission levels of NOx, SO_2 and particulates from this 50 megawatt plant are expected to be significantly lower than current standards. The project status, its participants, a description of the technology to be demonstrated, and the operational and performance goals of this project are presented herein.

Tidd PFBC Demonstration Project

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ABSTRACT

On March 30, 1995, one of the nation's pioneering Clean Coal Technology Projects -- the Tidd Demonstration Plant[1] in Brilliant, Ohio -- completed its 4-year test run, producing more than 11,500 hours of data for the power industry and establishing the technical foundation for cleaner, more efficient power plants in the 21st century.

The Tidd project was one of the first joint government-industry ventures to be approved by the U.S. Department of Energy (DOE) in its Clean Coal Technology Program. In March 1987, DOE signed an agreement with the Ohio Power Company, a subsidiary of American Electric Power, to refurbish the then-idle Tidd plant on the banks of the Ohio River with advanced "pressurized fluidized bed technology."

Testing ended after 49 months of operation, 100 individual tests, and the generation of more than 500,000 megawatt-hours of electricity. The demonstration plant has met its objectives. The project showed that more than 95 percent of sulfur dioxide pollutants could be removed inside the advanced boiler using the advanced combustion technology, giving future power plants an attractive alternative to expensive, add-on scrubber technology. During its test program, the Tidd Plant earned national honors for its innovative approach for power generation. In 1991, the plant was named Power Magazine's Power Plant of the Year. In 1992, the National Energy Resource Organization presented American Electric Power with a national award for its efforts in promoting energy efficient power technology.

In addition to its sulfur removal effectiveness, the plant's sustained periods of steady-state operation boosted its availability significantly above design projections, heightening confidence that pressurized fluidized bed technology will be a reliable, baseload technology for future power plants. The technology also controlled the release of nitrogen oxides to levels well below the allowable limits set by Federal air quality standards. It also produced a dry waste product that is much easier to handle than wastes from conventional power plants and will likely have commercial value when produced by future power plants.

At the time the 70-megawatt Tidd Plant was built, it represented a 13:1 scaleup from the earlier pilot plant facility. Future commercial PFBC plants will likely be in the 100 to 300 mega-

[1]Research sponsored by the U.S. Department of Energy's Morgantown Energy Technology Center under Cooperative Agreement No. DE-FC21-87MC24132 with the American Electric Power Service Corporation as agent for Ohio Power Company, 1 Riverside Plaza, Columbus, OH 43215

watt size range and feature efficiencies over 40 percent. More than 50 percent of new capacity added between 2000 and 2010 in the U. S. will be coal-based. High coal market capture rates are also anticipated in the international market. Compared to conventional technology, PFBC will have superior environmental and economic performance and is clearly a technology which will be used to meet the growing electricity demand worldwide.

The Tidd Project also served as the testing station for future devices that can clean unburned particles from the hot combustion gases with minimal losses in efficiency. The DOE used a "slip stream" of hot gases from the boiler to test advanced, ceramic barrier filters. Data acquired during 6,000 hours of operation will help in the design of the hot gas cleanup devices that will be needed as the technology further evolves.

The Tidd Project also gave the U.S. company, The Babcock & Wilcox Company, headquartered in Barberton, Ohio, the opportunity to strengthen its leadership role in developing high-technology boiler systems, demand for which is growing throughout the world.

Total project cost, including design, construction, and operation of the demonstration plant, was nearly $190 million, with DOE supplying $67 million, or 35%, and the project's co-sponsors providing nearly $123 million.

The materials shown at the Poster Session highlight the quantitative results of the testing and the commercial version of this technology at a utility scale. Information about obtaining the Final Report for the project will be available at the Poster Session.

Acknowledgments

The success of this project would not have been possible without the support and expertise of the project co-sponsors -- the State of Ohio and two major technology vendors, ASEA Brown Boveri Carbon and Babcock & Wilcox. The author also wishes to acknowledge the contribution of the Project Mangers Larry Carpenter and Donald Geiling at DOE's Morgantown Energy Technology Center.

McIntosh Unit 4 PCFB Demonstration Project

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Project Manager
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Lakeland, Florida

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Project Manager
Foster Wheeler Development Corporation
San Diego, California

Harry T. Morehead
Manager New Program Development
Westinghouse Electric Corporation
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Introduction

The City of Lakeland, Foster Wheeler Corporation and Westinghouse Electric Corporation have embarked on a utility scale demonstration of Pressurized Circulating Fluidized Bed (PCFB) technology at Lakeland's McIntosh Power Station in Lakeland, Florida. The U.S. Department of Energy will be providing approximately $195 million of funding for the project through two Cooperative Agreements under the auspices of the Clean Coal Technology Program. The project will involve the commercial demonstration of FOSTER WHEELER PYROFLOW PCFB technology integrated with Westinghouse's Hot Gas Filter (HGF) and power generation ® technologies.

The total project duration will be approximately eight years and will be structured into three separate phases; two years of design and permitting, followed by an initial period of two years of fabrication and construction and concluding with a four year demonstration (commercial operation) period. It is expected that the project will show that Foster Wheeler's Pyroflow PCFB technology coupled with Westinghouse's HGF and power generation technologies represents a cost effective, high efficiency, low emissions means of adding greenfield generation capacity and that this same technology is also well suited for repowering applications.

The project is being partially funded under the Clean Coal Technology Program by the US Department of Energy through its Morgantown Energy Technology Center under contracts DE-FC21-91MC27364 and DE-FC21-94MC21261 between DOE and the City of Lakeland.

The paper will provide a general description of the project including its objectives, structure and the roles of the various participants. The technology to be demonstrated will be described together with the project design basis and predicted performance. Current project activities will be discussed and planned future activities will be summarized.

Acknowledgment

The assistance of Mr. Don Geiling, METC's Project Manager for the McIntosh Unit 4 PCFB Demonstration Project, during the preparation and review of this paper is hereby gratefully acknowledged.

The project is being partially funded under the Clean Coal Technology Program by the US Department of Energy through its Morgantown Energy Technology Center under contracts DE-FC21-91MC27364 and DE-FC21-94MC21261 between DOE and the City of Lakeland.

Anatomy of an Upgraded Pulverized Coal Facility: Combustion Modification Through Flue Gas Scrubbing

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ABSTRACT

POWER PLANT ANATOMY 101 Regeneration is a biological term for formation or creating anew. In the case of Milliken station, a species of steam generation (Tangentus coali) regeneration refers to refitting critical systems with the latest technological advances to reduce emissions while maintaining or improving performance. The plant has undergone a series of operations which provided an anatomical changes as well as a face lift. Each of the two units were placed in suspended animation (outage) to allow these changes to be made. ~~The paper describes the project~~

The digestive system (combustion) was renewed from the molars to the sphincte
the system which grind the food (coal) prior to digestion (combustion) were repl
efficient, larger and stronger molars. All four molars (coal pulverizers) for each u
replaced with D.B. Riley MPS 150 mills with dynamic classifiers. In order to imp

cont'd on file

[1]Research sponsored by the U.S. Department of Energy's Pittsburgh Energy Technology Center, under contract DE-FCC 92PC92642 with New York State Electric & Gas Corporation, P.O. Box 5224, Binghamton, NY 13902-5224; telefax 6077-762-8457.

delivery to the stomach (boiler), a new esophagus (coal piping) has been installed. The stomach lining (boiler wall) has been fitted with ABB LNCFS III firing system which will increase energy and vitality while reducing indigestion and the formation of noxious gas (NO_x).

As with any well operating digestive system, gas and solids are by products of the process. The gas will be handled in a sensitive manner. Before expulsion to the atmosphere it will be conditioned through the intestines (back pass of the boiler, precipitator and scrubber). The small intestine (back pass of the boiler and precipitator) continue the digestive process by recovering additional calories and removing solids. A portion of the small intestine (precipitator) was enlarged to allow for its regeneration from a conventional weights and wires system to a Belco wide spaced ridged frame unit. ABB Air Preheater International is demonstrating a Q-Pipe Airheater for even greater heat recovery on Unit 2.

The digestion products are then passed through the large intestine (scrubber). Through this formic acid enhanced wet limestone process, process gas emissions (SO_2) are reduced and solids are processed into a useable cake (gypsum). Since Milliken was born without a large intestine, the scrubber was the most visible change which allowed for several cosmetic improvements.

The brain (control room) was considered to be A.B. Normal. Major surgery was performed to improve the units logic and memory capabilities. Additional nerve centers (DCS) and nerve sensors were added to improve efficiency, coordination and response time. After enduring all these changes Milliken has been given a TOPAZ system by DHR Technologies for on-line optimization and strategies for least cost plant operation.

Twenty-one reports will be issued prior to completion of testing in 1998. A listing of report titles and sample reports will be available at the poster display.

Acknowledgement

Mr. James U. Watts, DOE Project Manager; Demonstration Team Members: CONSOL Inc., Saarberg-Holter-Umwelttechnik. (SHU), NALCO Fuel Tech., DHR Technologies Inc., Stebbins Engineering, ABB Air Preheater. Project cofunders include NYSEG, CONSOL, Electric Power Research Institute, New York State Energy Research and Development Authority and Empire State Electric Energy Research Corporation. Parsons Power Group is the Arthitect/Engineer and Construction Manager for the flue gas desulfurizatoin (FGD) retrofit portion of the project.

DB RILEY—LOW EMISSION BOILER SYSTEM (LEBS): SUPERIOR POWER FOR THE 21ST CENTURY

PRIMARY PROJECT PARTNER

DB Riley, Inc.
Worcester, MA

MAIN SITE

Worcester, MA

TOTAL ESTIMATED COST

$116,000,000

COST SHARING

DOE	$42,500,000
Non-DOE	$73,500,000

Project Description

In conjunction with the U.S. Department of Energy, DB Riley, Inc., is developing a highly advanced coal-fired power-generation plant called the Low Emission Boiler System (LEBS). By the year 2000, LEBS will provide the U.S. electric power industry with a reliable, efficient, cost-effective, environmentally superior alternative to current technologies.

LEBS incorporates significant advances in coal combustion, supercritical steam boiler design, environmental control, and materials development. It employs the combustion expertise of Deutsche-Babcock, the University of Utah, and Reaction Engineering International; the pollution-control experience of Thermo Power Corporation; and the plant design practices of Sargent & Lundy Engineers.

The system will include a state-of-the-art steam cycle operating at supercritical steam conditions; a slagging combustor that produces vitrified ash by-products; low nitrogen oxide (NOx) burners; a new, dry, regenerable flue gas cleanup system (copper oxide process) for simultaneously capturing sulfur dioxide (SO_2) and nitrogen oxides (NOx); a pulse-jet fabric filter for particulate capture; and a low-temperature heat-recovery system.

The copper oxide flue gas cleanup system, which has been under development at DOE's Pittsburgh field center, removes over 98% of SO_2 and 95% of NOx from flue gas. A new moving-bed design provides efficient sorbent utilization that lowers the cleanup process cost. The captured SO_2 can be converted to valuable by-products such as sulfuric acid and/or elemental sulfur, and the process generates no waste.

Program Goal

DOE's strategic plan aims not only to ensure a reliable and affordable energy supply for the U.S., but also to minimize adverse environmental impact. The highly advanced coal-fired LEBS will achieve significantly lower emissions and higher plant efficiencies than conventional units. Performance objectives of LEBS include plant thermal efficiencies of 42%; lower emission levels of SO_2, NOx, and particulates; and a cost of electricity equal to or less than that of conventional coal-fired power plants.

Project Partners

SARGENT & LUNDY ENGINEERS
Chicago, IL
(plant design)

THERMO POWER CORPORATION
Waltham, MA
(pollution control)

UNIVERSITY OF UTAH
Salt Lake City, UT
(combustion)

REACTION ENGINEERING INTERNATIONAL
Salt Lake City, UT
(combustion)

DB RILEY—LOW EMISSION BOILER SYSTEM (LEBS): SUPERIOR POWER FOR THE 21ST CENTURY

Project Benefits

In the near future, the United States will have to build a new generation of coal-based power plants to replace its aging units. Coal supplies more than 56% of the nation's electricity, and, because of our abundant reserves, it will remain the dominant source of fuel for power generation well into the next century. A national cap on sulfur and nitrogen oxide (NOx) emissions, however, will require future coal technologies to be much cleaner than current technology.

DOE is sponsoring the Low Emission Boiler System Program to meet these power and environmental needs. Without significantly departing from the traditional design features of pulverized coal-firing systems, this technology will:

- Reduce sulfur dioxide and NOx emissions to a sixth of the levels allowed by today's Federal air quality standards (New Source Performance Standards).
- Lower emissions of flyash and other particulates to a third of those allowed by today's standards.
- Significantly improve power-plant efficiency—from today's level of 35% up to 48%.
- Produce electricity at costs equal to or less than those of a modern-day coal plant.

LEBS is one of several advanced power generation systems that are being developed with support from DOE. Of these systems, LEBS offers the nearest-term commercial option for utilities to meet these performance goals for new installations. In addition, many of the technologies that are being developed in the LEBS Program will be available for retrofit or repowering applications at existing facilities.

DB Riley, along with ABB-Combustion Engineering and Babcock & Wilcox, are leading independent teams to develop low emission boiler systems that incorporate each team's unique, preferred technologies. In mid-1997, one of the teams will be selected to construct and operate a proof-of concept (POC) test facility to provide the engineering data for commercializing its system by the year 2000.

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Cost Profile (Dollars in Millions)

	Prior Investment	FY95	FY96	FY97	Future Funds**
Department of Energy*	[illegible]	$2.1	$2.0	$8.5	[illegible]
Private Sector Partners	[illegible]	$0.8	$0.7	$6.9	[illegible]

* Appropriated Funding

** If DB Riley is selected to design, construct, and operate a proof-of-concept power plant, a total of about $100 million ($20 million DOE) will be required with $6 million needed in FY97.

Key Milestones

FY91	FY92	FY93	FY94	FY95	FY96	FY97	FY98	FY99	FY00
Planning and Development				Design and Testing		Design	Construction and Operation		
	Concept development Preliminary R&D Component testing Commercial generating unit preliminary design			Subsystem testing Proof-of-concept facility: preliminary design Selection of host site for POC facility		POC facility: revised design Commercial generating unit: revised design		Construction and operation of POC facility	

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