Wabash River Coal Gasification Repowering Project - First Year Operation Experience Fifth Annual Clean Coal Technology Conference

E. J. (Chip) Troxclair (812-535-6050)
Destec Energy, Inc.
2500 CityWest Boulevard, Suite 150
Houston, Texas 77042

Jack Stultz (812-535-2451)
PSI Energy, Inc.
445 Bolton Road
West Terre Haute, IN 47885

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.

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DOE Project Manager: Gary Nelkin
Participant Joint Venture Manager: Phil Amick, Destec Energy, Inc.
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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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