DOE/FE-0448

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT JOINT VENTURE

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PROJECT PERFORMANCE SUMMARY
CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

JULY 2002

Disclaimer

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ADVANCED ELECTRIC POWER GENERATION

Wabash River Coal Gasification Repowering Project

Overview

Global Energy's E-Gas™ gasification technology represents a new approach to meeting 21st century domestic and global energy and environmental demands. The technology offers the potential for near-zero pollutant emissions, significant gains in efficiency, fuel and product flexibility; and enables carbon dioxide capture and separation for recycle or sequestration.

This project is part of the U.S. Department of Energy's (DOE) Clean Coal Technology Demonstration Program (CCTDP) established to address energy and environmental concerns related to coal use. DOE sought cost-shared partnerships with industry through five nationally competed solicitations to accelerate commercialization of the most promising advanced coal-based power generation and pollution control technologies. The CCTDP, valued at over five billion dollars, has significantly leveraged federal funding by forging effective partnerships founded on sound principles. For every federal dollar invested, CCTDP participants have invested two dollars. These participants include utilities, technology developers, state governments, and research organizations. The project presented here was one of nine selected from 33 proposals submitted in September 1991 in response to the CCTDP's fourth solicitation.

In this project, the then gasification technology owner, Destec Energy, Inc. (later acquired by Dynegy and then Global Energy), forged a joint venture with a major utility, PSI Energy, Inc. (now owned by Cinergy Corporation), to pioneer commercial introduction of integrated gasification combined-cycle (IGCC) power generation technology. In 1992, the resultant Wabash River Coal Gasification Repowering Project Joint Venture (WRCGRP) embarked on a demonstration of Global Energy's E-Gas™ gasification technology in an IGCC mode at 262-MWe scale — then, the world's largest single-train IGCC. Seven years later, the project culminated with the unit successfully competing in Cinergy's system for base-load power and carrying the distinction of being one of the cleanest coal-based power systems in the world.

The project repowered a 1950s vintage pulverized coal-fired plant, transforming the plant from an approximately 33% efficient, 90-MWe unit operating on unscrubbed compliance coal into an approximately 40% efficient, 262-MWe unit meeting or surpassing current and projected emissions standards. Moreover, the technology operates efficiently on a range of coals, as well as petroleum coke (a refinery waste); produces high-value byproducts in lieu of solid wastes; and provides the potential for co-production of chemicals and clean fuels.

Accolades for accomplishments have been bestowed on the project by both the power industry and the public over the course of the demonstration. Recognized was the foresight and engineering expertise necessary to introduce a new approach to power generation and to also integrate many new technical advances. For example, the project used one of General Electric's (GE) initial production Frame 7FA high-temperature gas turbines and was the first to operate it on synthesis gas (syngas). *Power* magazine presented the project the 1996 Powerplant Award and induction to the Power Plant Hall of Fame Award in 2000, and the State of Indiana conferred the Indiana Governor's Award for Excellence in Recycling.

The Project

Round IV of the CCTDP placed particular emphasis on advanced power generation systems that could provide capacity additions without exceeding existing and projected emissions caps, as well as major efficiency gains to counter global climate change concerns. In response, PSI Energy and Destec Energy developed a project to introduce gasification-based power generation with the primary goal of integrating the system into the utility grid in baseload commercial service. More specifically, the project set out to displace the 40-year old, 90-MWe pulverized coal-fired Unit 1 at PSI Energy's Wabash River Generating Station with an ultra-clean, highly efficient 262-MWe (net) integrated gasification combined-cycle system.

Challenges included extending E-Gas™ previous experience, solely with low-sulfur subbituminous coals, to high-sulfur bituminous coals indigenous to Indiana. Technical advancements had to be integrated to accommodate differences in ash behavior and the need for high-capacity sulfur capture and conversion. At the very high sulfur levels anticipated (up to 5.9% sulfur), carbonyl sulfide (COS) becomes an issue — yet, there was no direct experience to draw on for COS removal from syngas. Also, to meet efficiency goals in a repowering application required a high degree of integration between the gasification heat recovery system, heat recovery steam generator (HRSG), and existing reheat steam turbine. Efficiency goals also prompted use of a newly introduced high-efficiency gas turbine produced by GE — the Frame 7FA — which had never operated before on syngas.

Additionally, the project set tough environmental performance targets. Despite planned use of 5.9% sulfur coal, the WRCGRP set SO_2 emission targets at one-sixth of the allowable emissions under the Clean Air Act Amendments of 1990 (CAAA). NO_x emission targets were consistent with levels projected for ozone non-attainment areas. Furthermore, barrier filters for turbine protection were to render particulate emissions essentially non-existent.

Lastly, integration with the utility grid required an annual availability factor of over 70% — a target of 75% was established. To achieve established performance targets and to evaluate and document major process component and subsystem performance, the WRCGRP mounted a four year demonstration campaign, which systematically addressed and successfully met the technical challenges.

Project Sponsor
Wabash River Coal Gasification Repowering Project Joint Venture

Team Member Functions
PSI Energy, Inc. — host
Destec Energy, Inc. (now Global Energy) — engineer and gas plant operator

Location
West Terre Haute, Vigo County, IN (PSI Energy's Wabash River Generating Station, Unit No. 1)

Technology
Integrated gasification combined-cycle (IGCC) using Global Energy's two-stage, pressurized, oxygen-blown, entrained-flow gasification system — E-Gas™ technology

The technology was developed by Dow Chemical Company and transferred to Destec, a partially held subsidiary of Dow. In 1997, NGC/Dynegy acquired Destec. In 1999, Global Energy acquired Dynegy's gasification assets and technology.

Plant Capacity/Production
296 MWe (gross), 262 MWe (net)

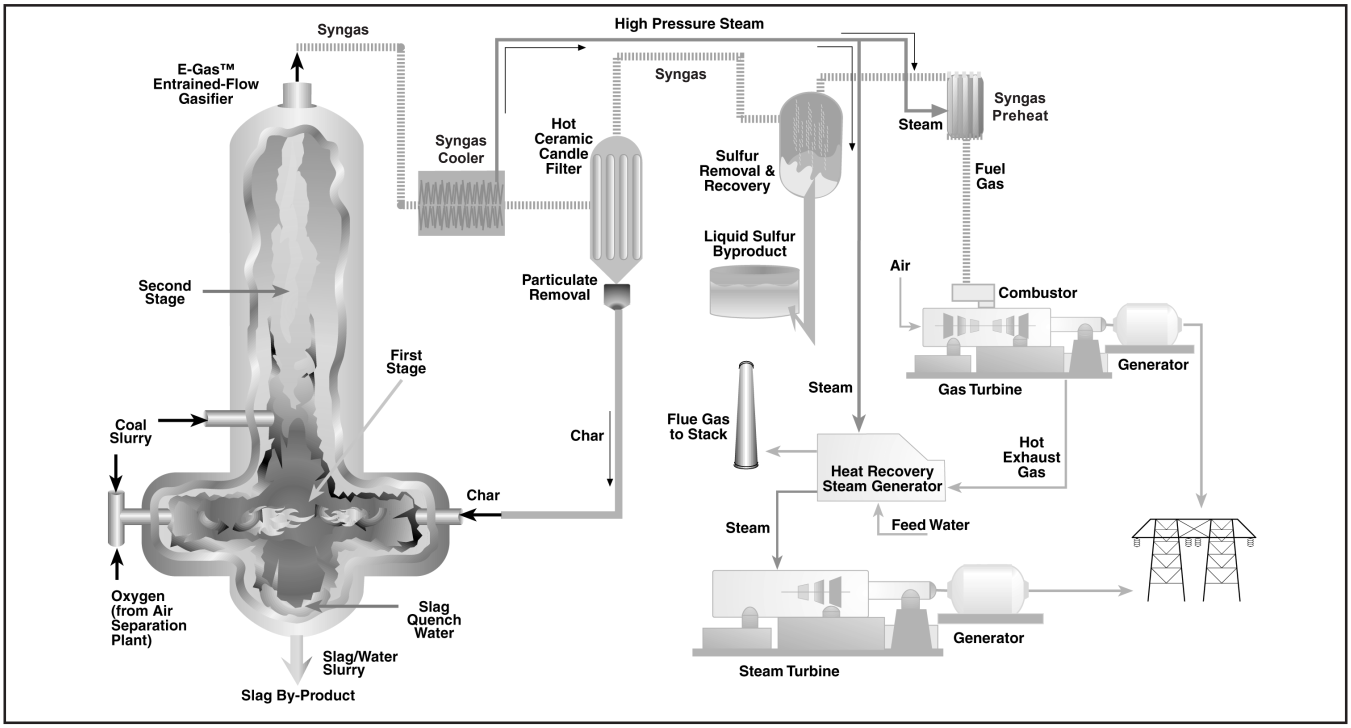
Fuel
Illinois Basin bituminous coal
Petroleum coke

Demonstration Duration
December 1995 - December 1999

Project Funding

Total Project Cost	$438,200,000
DOE	219,100,000
Project Sponsor	219,100,000

The Technology



E-Gas™ technology features a pressurized, oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier. Coal (or petroleum coke) is milled with water in a rod mill to form a 60/40 percent by weight coal/water slurry. An air separation unit provides 95% pure oxygen that is combined with the slurry in mixer nozzles and is injected into the first stage of the gasifier. In the first stage, the slurry, along with recycled char, undergoes a partial oxidation reaction at 400 psig. The resultant 2,600°F temperature causes rapid gasification of the coal (or petroleum coke) and the ash to melt and flow. The fluid ash flows through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag.

Raw syngas from the first stage flows into a vertical second stage reactor, where additional slurry (without oxygen) is introduced. The coal (or petroleum coke) devolatilizes, pyrolyzes, and partly gasifies by reaction with steam. These reactions enhance the heating value of the syngas, and the endothermic reactions and water evaporation reduce the syngas temperature to about 1,900°F. Reducing the temperature in this manner improves process efficiency and eliminates the need for a large, expensive radiant heat exchanger. Syngas exiting the gasifier is cooled to 700°F in a cooler, which is a vertical fire-tube boiler. This high-temperature heat-recovery unit (HTHRU) produces high-pressure (1,600 psia) saturated steam.

Cooled syngas passes through a hot candle filter that removes the flyash and char and recycles it to the first stage gasifier. Dry filtration is used, as opposed to wet methods, to meet efficiency targets. The filter uses metallic candle filters that were further developed and refined during the course of the demonstration. The metallic filters replaced the ceramic filters originally used.

The syngas is further cooled in a series of heat exchangers, water-scrubbed to remove chlorides, and passed through a catalyst that hydrolyzes COS to hydrogen sulfide (H_2S). The H_2S is then removed in the acid gas removal system using methyldiethanolamine (MDEA) absorber/stripper columns. A sulfur recovery unit, based on the Claus process, partially oxidizes the H_2S and converts it to pure sulfur and steam. Syngas, devoid of acid gases, is then preheated, moisturized and piped to the power block, where it is combusted in a GE MS7001FA high-temperature gas turbine.

The HRSG uses both the gas turbine exhaust energy and the saturated steam from the HTHRU to provide super-heated steam to an existing 1952 vintage Westinghouse reheat steam turbine. The steam turbine is designed to produce 104 MWe, and together with the 192 MWe gas turbine, the plant design output is 296 MWe gross, with a 34-MWe auxiliary load (262 MWe net).

Results Summary

Environmental

- The SO_2 capture efficiency was greater than 99%, keeping SO_2 emissions consistently below 0.1 lb/10^6 Btu and reaching as low as 0.03 lb/10^6 Btu. Sulfur-based pollutants were transformed into 99.99+% pure sulfur, a highly valued product. A total of 33,388 tons of sulfur were produced during the demonstration.
- NO_x emissions were 0.15 lb/10^6 Btu, which meets 2003 target emission limits for ozone non-attainment areas, or 1.09 lb/ MWh, which outperforms New Source Performance Standards (NSPS) of 1.6 lb/ MWh. Particulate emissions were below detectable limits, and carbon monoxide emissions, averaging 0.05 lb/10^6 Btu, were well within industry standards.
- Coal ash was converted to a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as a grit for abrasives and roofing materials. Trace metals from petroleum coke were captured and encased in the vitreous slag.

Gasifier structure

Operational

- Over the course of the demonstration, the IGCC unit operated on coal for over 15,000 hours, processed over 1.5 million tons of coal, and produced over 23 trillion Btu of syngas and 4 million MWh of electricity.
- A number of problems were overcome and improvements were made over the course of the demonstration, bringing average gasification block availability up to 70% in 1999, and reaching as high as 77% during a 9 month period in 1998-1999. The plant demonstrated stable operation on the utility grid in a baseload dispatch mode.
- Ash deposition on the second stage gasifier walls and fire-tube boiler inlet was corrected by using a less tenacious refractory material and modifying the hot gas path flow geometry and velocity. An effective mechanical cleaning system for the fire-tube boiler was developed. Improvements in rod mill operation and burner design reduced slag carbon content from 10% to 5%.
- Particulate filtration system problems were remedied by replacing ceramic candle filters with metallic candle elements and improving flow distribution to, and back-pulse cleaning of, the filter elements.
- Installation of a wet chloride scrubber eliminated early poisoning of the COS hydrolysis catalyst and chloride stress corrosion cracking of low temperature heat exchanger tubes. Also, a COS catalyst less prone to poisoning was installed. Acid gas removal performance was successfully improved by expanding the capacity of the heat stable salt removal system.
- With few exceptions, the combustion turbine and its related components operated as expected over the course of the project. In 1999, however, a catastrophic failure of the air compressor rotor and stator occurred, unrelated to operation on syngas. Other minor incidents involved the combustion turbine expansion bellows, solenoid valves in the syngas purge lines, and fuel nozzles.

Economic

- The capital cost of the demonstration unit was \$1,590/kW in 1994 dollars. The capital cost for an equivalent sized greenfield commercial configuration with an 8,250 Btu/kWh heat rate was estimated to be \$1,250–1,300/kW in year 2000 dollars for a coal-fueled unit and \$1,100–1,200/kW for a petroleum coke-fueled unit (due to reducing the size and eliminating some equipment).

Operational Performance

Table 1 summarizes the production statistics for the project. Over the four-year demonstration period starting in November 1995, the plant operated on coal for more than 15,000 hours and processed over 1.5 million tons of coal to produce more than 23 trillion Btu of syngas. For several of the months, syngas production exceeded one trillion Btu. By the end of the demonstration, the 262-MWe IGCC unit had captured and produced 33,388 tons of sulfur.

Table 1. WRCGRP Production Statistics

Time Period	On Coal (Hr)	Coal Processed (tons)	On Spec. Gas (10^6 Btu)	Steam Produced (10^3 lb)	Power Produced (MWh)	Sulfur Produced (tons)
Start-up 1995	505	41,000[a]	230,784	171,613	71,000[a]	559
1996	1,902	184,382	2,769,685	820,624	449,919	3,299
1997	3,885	392,822	6,232,545	1,720,229	1,086,877	8,521
1998	5,279	561,495	8,844,902	2,190,393	1,513,629	12,452
1999[b]	3,496	369,862	5,813,151	1,480,908	1,003,853	8,557
Overall	15,067	1,549,561	23,891,067	6,383,767	4,125,278	33,388

[a]Estimated

[b]The combustion turbine was unavailable from 3/14/99 through 6/22/99.

Figure 1. Project, Syngas Block, and Power Block Availability

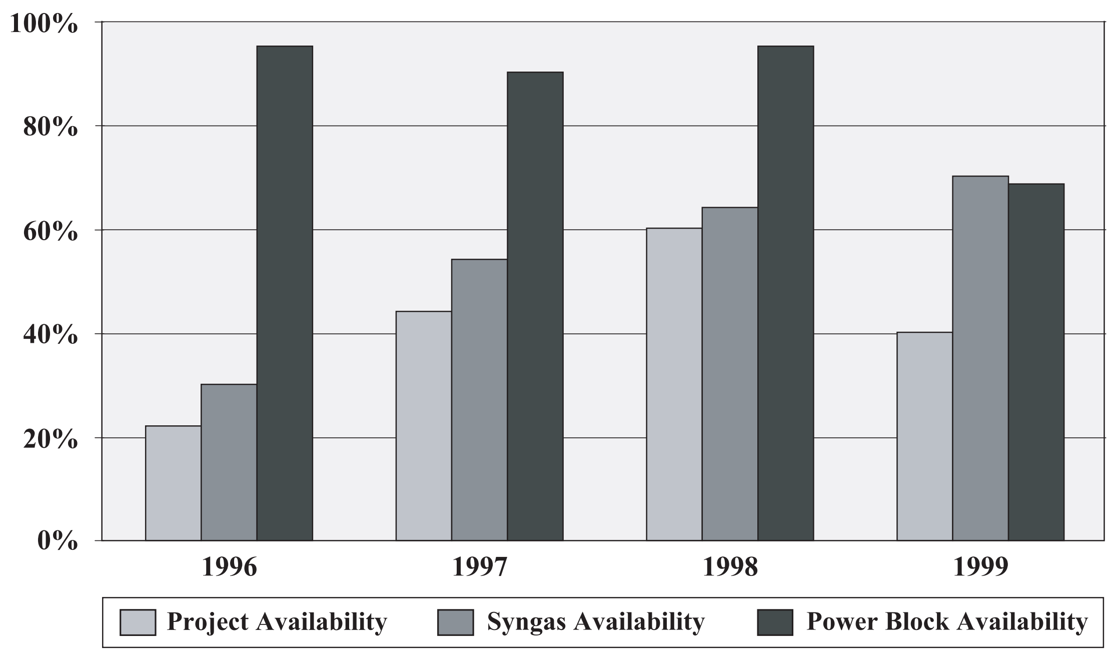


Figure 1 shows how the reliability of the technology advanced during the demonstration. The continuous improvement trend for the gasification block, where the majority of the novel technology resides, is encouraging and is expected to continue. During the third quarter of 1999, the gasification block produced a record 2.7 trillion Btu of syngas and operated continuously without any interruption for 54 days. Over the last year of the demonstration, the gasification block achieved 70% availability and achieved as high as 77% availability over one nine-month period in 1998–1999. The project and power block availability values for 1999 are skewed by the 100-day downtime experienced as a result of a combustion turbine compressor failure unrelated to operation on syngas. At the time of this report, the unit continues to operate as part of the utility power generation system, competing with Cinergy's alternatives for peak and off-peak power. Competitive market-based pricing allows the syngas facility to run at base-load in Cinergy's system.

WRCGRP's efforts resulted in all goals and objectives of the project being met and in unanticipated successes as well. While fuel changes were not planned, the system operated effectively, without modification or incident, on petroleum coke (petcoke) and on blends and combinations of bituminous coals that sometimes changed daily. This performance proved the fuel flexibility of the system, which had previously processed lignite and subbituminous coals during its development. While processing over 18,000 tons of high-sulfur petcoke during demonstration in 1997, the unit produced 350 billion Btu of syngas, demonstrated enhanced thermal efficiency, and encountered negligible tar production and no problem in handling the increased dry char particulate production. Table 2 summarizes the coal and petcoke characteristics and plant performance on these fuels.

Table 2. Fuel/Product Characteristics and Plant Performance

Fuel Analysis

Component	Typical Coal	Petroleum Coke
Moisture, %	15.2	7.0
Ash, %	12.0	0.3
Volatile Matter, %	32.9	12.4
Fixed Carbon, %	39.9	80.3
Sulfur, %	1.9	5.2
HHV, Btu/lb	10,536	14,282

Product Syngas Analysis

Component	Typical Coal	Petroleum Coke
Nitrogen, Vol %	1.9	1.9
Argon, Vol %	0.6	0.6
CO_2, Vol %	15.8	15.4
CO, Vol %	45.3	48.6
H_2, Vol %	34.4	33.2
CH_4, Vol %	1.9	0.5
Total Sulfur, ppmv	68	69
HHV, Btu/SCF	277	268

Plant Performance

	Design Coal	Actual Coal	Actual Petcoke
Throughput, tons/day	2,550	2,450	2,000
Syngas Output, 10^6 Btu/hr	1,780	1,690	1,690
Gas Turbine, MWe	192	192	192
Steam Turbine, MWe	105	96*	96*
Parasitic Load, MWe	35	36	36
Net Power, MWe	262	252	252
Plant Efficiency (HHV), %	37.8*	39.7*	40.2*
Sulfur Removal, %	>98	>99	>99

*Lower steam turbine output resulted from feedwater heater failure. Thermal efficiency numbers are corrected for this failure.

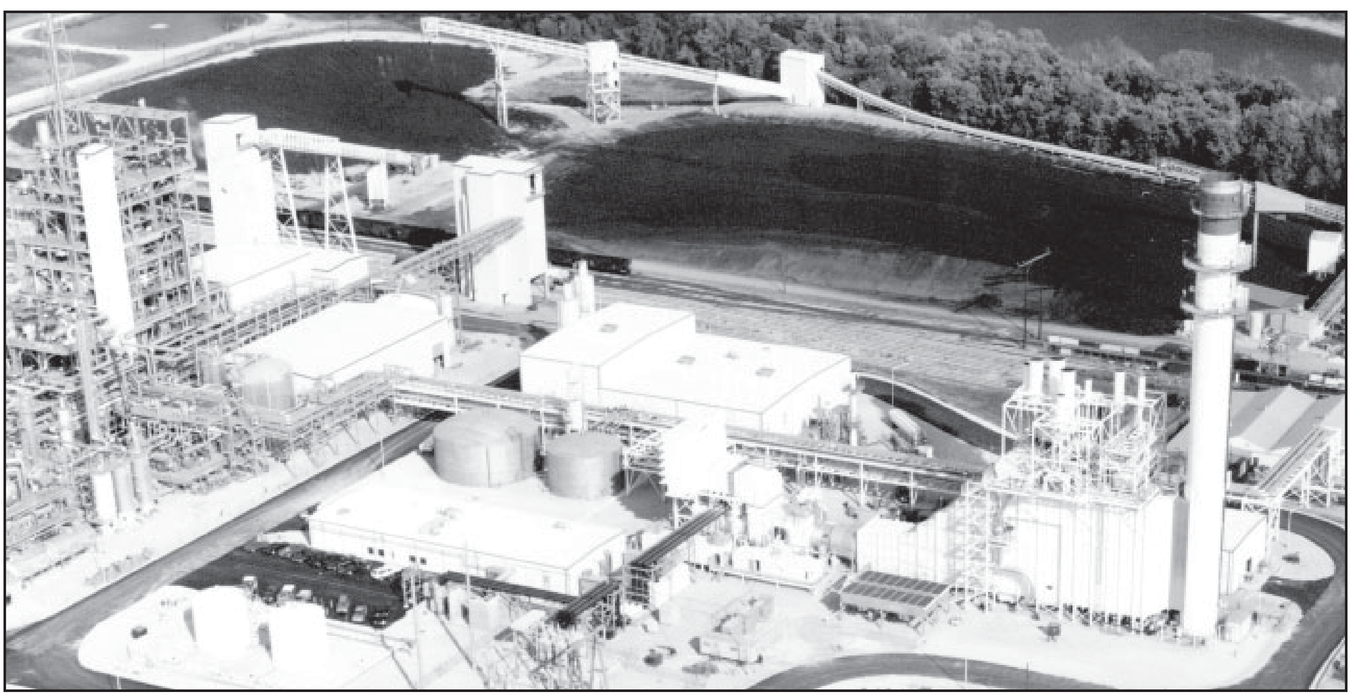
In carrying out the successful four year campaign to engineer the demonstration unit into a viable commercial unit, the WRCGRP encountered a broad range of problems, including the usual quality control and nuisance problems. Summarized here are some of the major challenges overcome and important lessons learned. They are presented topically in the order in which the system or component appears in the process.

Air Separation Unit (ASU). The 2,060 ton per day Liquid Air Engineering Corp. (LAEC) ASU failed to display the high availability characteristic of industrial ASUs, fell short of targeted nitrogen production levels, and exceeded power consumption targets. Poor weatherproofing of key components, quality control problems, and a poorly designed instrumentation system contributed to downtime. The largest ASU downtime item was the inlet guide vane actuator system, which ultimately had to be replaced with a new design. Failure to meet targeted nitrogen production and power consumption initially resulted in higher than expected operating and maintenance costs for power and imported nitrogen. However, nitrogen conservation measures adopted during startup reduced consumption. A lesson learned is that ASUs using batch type air purification, such as the LAEC unit, must reduce capacity during the transition of adsorber beds from adsorption to regeneration. This temporary reduced capacity should be taken into account when sizing equipment.

Coal Handling. The coal delivery system for the gasifier performed well, although several upgrades were made. These upgrades included hardening or metallurgically altering components to better resist erosion and corrosion, and modifying the slurry tank agitator to reduce localized buildups. Moreover, the rod mill rod charge was adjusted to provide optimum particle size distribution for flow and for carbon conversion in the gasifier.

Gasification. Efficient operation of the gasifier requires that first stage temperatures are hot enough to ensure molten slag flows from the taphole, but not so hot that refractory damage results. Striking this balance continues to be a challenge because direct temperature measurements proved to be unreliable. Operators had to rely heavily upon indirect observations to control temperature. After five taphole plugging events following feedstock changes, investigators developed feed-specific guidelines to prevent further problems.

Ash deposition problems plagued early operations. Ash deposits formed on the walls of the second stage gasifier and downstream piping. As deposits built up, they forced the plant off line by either inducing unacceptable pressure differentials or breaking free and plugging downstream lines or HTHRU tubes. Drawing upon computational fluid dynamic modeling, the problem was corrected by: (1) using a refractory in the second stage resistant to tenacious ash bonds and having reduced thickness to lower gas flow velocity; (2) replacing the



Wabash River Generating Station IGCC plant — gasifier and gas cleanup to left and gas turbine and HRSG to right

refractory lined pipe spool between the gasifier and HTHRU with a smooth, continuous transition spool to eliminate high velocity impact zones; and (3) installing a screen at the HTHRU inlet to catch any remaining deposits.

The slurry mixers that serve to mix and inject the coal/water/oxygen into the first stage gasifier proved to be a reliability challenge given the abrasive characteristics of the coal coupled with the hostile environment of high temperatures and slag. After early struggles to maintain reasonable performance, a breakthrough was made by redesigning the mixer throat and face. The redesign doubled mixer life and, along with earlier rod mill adjustments, reduced carbon in the slag from 10% to 5%.

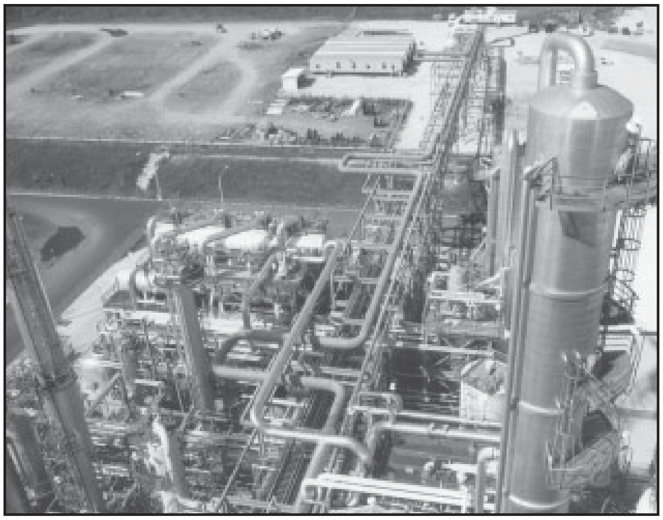
HTHRU (Syngas Cooler). Despite improvements in design and operating conditions to reduce fouling, routine removal of deposits from the HTHRU boiler tubes is required at scheduled outages. Cleaning is needed to prevent reduction of heat transfer effectiveness and thus ensure the integrity of downstream temperature sensitive components, such as filter elements. The deposits are particularly hard and tenacious, which prompted maintenance personnel to develop a special tool. Standard mechanical cleaning methods proved to be ineffective and chemical methods expensive and time consuming. The solution was an adaptation of a core drill to bore out the tubes.

Particulate Removal. The particulate removal system accounted for nearly 40% of the total downtime in the first year of operation. A concerted effort on the part of a team dedicated to resolving the underlying problems has resulted in bringing the system up to acceptable performance levels and making the prospects for future performance bright.

In early operation, many ceramic tie-rod type candle filter elements sustained sufficient damage, both during installation and in service, to cause breakthrough of particulate matter, which overwhelmed the secondary safeguard system. Failures strongly suggested that the long slender, relatively brittle ceramic candles could not readily adjust to either dimensional discontinuities introduced through the mounting hardware or thermal gradients induced in service. The frequent start-ups and shutdowns experienced in the early operating period likely exacerbated the problem.

A change to metallic candle elements in late 1996 immediately improved system reliability. The switch to metallic candles, however, introduced the challenge of overcoming corrosion. Filter blinding, a problem with ceramic filters,

Coal receiving and handling area



Gas cleanup system

remained a problem with metallic filters. Metallurgical advancements made significant inroads into solving the corrosion problem. The advancements were aided by installation of a slipstream test apparatus to evaluate effectiveness of new filter elements, as well as mounting hardware. Blinding problems were significantly reduced by: (1) modifying the gas distribution in the filter vessel to even out flow and eliminate localized high-velocity channeling; and (2) improving operation and control of the back-pulse cleaning system.

Operational experience pointed out the importance of having safeguard devices (SGD) integrated with each filter element to prevent catastrophic breakthrough of particulate matter. SGDs are essentially packings that are designed to offer little flow resistance during normal operation and plug when subjected to high dust loadings. The team working on the particulate removal system developed such devices and, due to their success, the SGDs displaced the secondary filter system.

Low Temperature Heat Recovery/COS Hydrolysis. In the early stages of operation, extensive tube failures occurred in the low temperature heat recovery system, and the COS hydrolysis catalysts incurred poisoning. Investigation revealed the root cause to be chloride induced stress corrosion cracking of the exchanger tubes and chloride and trace metal poisoning of the COS catalyst. Integration of a chloride scrubber, which was accomplished in the first year of operation, eliminated the chloride problem. As a result of the catalyst poisoning incident, investigators sought a more durable catalyst and, through slipstream testing, identified and adopted a new catalyst material, which appears to have the desired 5-year life.

Acid Gas Removal. Acid gas removal improvement efforts focused on the MDEA reclaim unit, the most costly piece of equipment in the system and one having direct impact on sulfur removal. Early actions included (1) structural modification of the canisters containing the ion exchange resin to prevent dissolution, and (2) changes to the solution designed to remove unwanted heat stable salts from the ion exchange resin. Heat stable salt buildup persisted, however, requiring frequent and costly on-site vacuum distillation or solution replacement. In the last year of operation, the problem was resolved by increasing system capacity with a supplemental amine storage tank. WRCGRP suggests future MDEA reclaim designs be simplified to reduce capital and maintenance costs. They found the continuous-feed, rotating canister design unnecessarily complex and difficult to maintain. A suggested system is a three cell unit swapping flow from online, regeneration, and stand-by resin beds using automated block valves.

Combustion Turbine. With few exceptions, the combustion turbine and its related components operated as expected over the course of the project. In 1999, however, a catastrophic failure of the air compressor rotor and stator occurred. Apparently other gas turbines operating on natural gas experienced similar events. General Electric concluded that this failure was not related to operation on syngas. An upgraded compressor unit was installed. Other minor occurrences prompted improvements in other areas. These include: (1) redesign and replacement of expansion bellows between the syngas module and the turbine to eliminate flow sleeve cracking; (2) redesign and replacement of solenoid valves in the syngas purge lines; and (3) replacement of fuel nozzles to remedy combustor liner cracking.

HRSG. The HRSG experienced an abnormal number of tube leaks attributed primarily to piping circuits being supported from the bottom rather than hung from the ceiling. Supporting at the bottom limited movement of the piping and induced stress at tube bends during expansion and contraction. Moreover, superheater and reheat section header expansion joints failed due to interference with penthouse roof panels upon heat up.

Environmental Performance

The COS hydrolysis and MDEA acid gas removal systems combined to achieve an average SO_2 emission rate of 0.1 lb/10^6 Btu, with interim emission rates reaching as low as 0.03 lb/10^6 Btu. This represents a 99% reduction of the potential SO_2 emissions based on the sulfur content of the design coal. The CAAA year 2000 standards for SO_2 control serve to underscore the dramatic sulfur reduction achieved. These standards limit SO_2 emissions to 1.2 lb/10^6 Btu of heat input and a sliding scale requiring 70–90% reduction from the uncontrolled emissions rate, which generally works out to about 0.6 lb/10^6 Btu for high sulfur bituminous coals.

Moreover, the sulfur captured is transformed into 99.99+% pure sulfur — a salable product. Over the four year demonstration period, 33,388 tons of pure sulfur were produced, contributing to the economy rather than environmental concerns.

There are two regulatory drivers for low NO_x emissions applicable to projects such as the WRCGRP: (1) recently revised NSPS for NO_x of 1.6 lb/MWh based on power output rather than heat input, and (2) NO_x emission limits of 0.15 lb/10^6 Btu to be met in 2003 by existing power sources in 22 eastern states and the District of Columbia. WRCGRP readily complies with both standards. Moisturizing the syngas in combination with steam injection in the gas turbine easily sustained NO_x emission rates of 0.15 lb/10^6 Btu and 1.09 lb/MWh.

Existing standards for particulate matter at the time of the project limited total particulate emissions to 0.03 lb/10^6 Btu. Monitoring was required for particulate matter in the range of 10 microns or less (PM_{10}) to address National Ambient Air Quality Standards (NAAQS). The NAAQS underwent a subsequent revision towards the end of the project to address fines in the respirable range of 2.5 microns or less ($PM_{2.5}$). As this report is released, a national $PM_{2.5}$ monitoring program is underway to establish non-attainment areas and to attribute $PM_{2.5}$ levels to sources. Sulfates and nitrates derived from SO_2 and NO_x emissions become a concern, as well as flyash, for particulate matter in this size range. These factors combine to make E-Gas™ technology an important power generation option for the future — particulate emissions are below the detectable limit and SO_2 and NO_x precursors to $PM_{2.5}$ are extremely low.

Carbon monoxide emissions averaged 0.05 lb/10^6 Btu, essentially the same as the displaced plant and well within industry standards.

The ash component of the coal is transformed into a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as a grit for abrasives and roofing materials. Slag fines are recycled to the gasifier to enhance carbon recovery. Also, trace metal constituents in petroleum coke are effectively captured in the slag produced.

Air toxics monitoring proved that airborne hazardous air pollutants (HAPS) are not a problem with the IGCC plant. This was not surprising given that particulate emissions were below detectable limits and that HAPS largely associate with particulate matter. Even mercury, which adopts a vapor phase and often escapes capture, presented no problem, with emissions ranging from 0.0002–0.0009 pounds per hour. Some volatile trace elements fully or partially partitioned into the gas phase and ended up in the condensed vapor stream, leaving the process via the waste water stream. Arsenic, selenium, and cyanide built up in the waste water, which required post project action to correct. WRCGRP identified two options showing promise — evaporation and reverse osmosis — with evaporation finally selected to ensure removal of certain speciation of trace metals.

Steam lines from HRSG

Economic Performance

The overall cost of the IGCC demonstration plant was \$417 million, which equates to about \$1,590/kW in 1994 dollars. Costs include engineering, environmental permitting, equipment procurement, project and construction management, construction and start-up, and hiring and training personnel. Costs exclude fuel supply, interest during construction, financing fees, and license fees.

Capital cost estimates for a new 262-MWe greenfield IGCC plant incorporating lessons learned, technology improvements, and a heat rate of 8,250 Btu/kWh are \$1,250–1,300/kW (year 2000 dollars) for a coal-fueled unit and \$1,100–1,200/kW (year 2000 dollars) for a petroleum coke-fueled unit. In designing for petroleum coke, some equipment can be reduced in size and some can be eliminated.

Annual fuel costs for the Wabash project ranged from \$15.3–19.2 million, with an annual availability of 75% and using high-sulfur bituminous coal ranging from \$1.00–1.25/10^6 Btu (\$22–27/ton). Non-fuel operations and maintenance (O&M) costs for the syngas facility (excluding the power block) was 6.8% of installed capital based on 75% availability. O&M costs include operating labor and benefits, technical and administrative support on- and off-site, maintenance, chemicals, waste disposal, operating services and supplies, and 5% of the total O&M cost for betterments. Projected O&M costs for a mature IGCC facility (including the power block) are 5.2% of installed capital costs.

Economic analyses showed that a coal-fueled Wabash River style IGCC required power pricing of \$34–42/MWh for a 12% internal rate of return (IRR), depending on a reasonable range of capital and O&M costs and availability. For a similar petroleum coke-fueled plant and 12% IRR, the estimated power pricing requirements are \$24–30/MWh, again depending on a reasonable range of capital and O&M costs and availability.

Commercial Applications

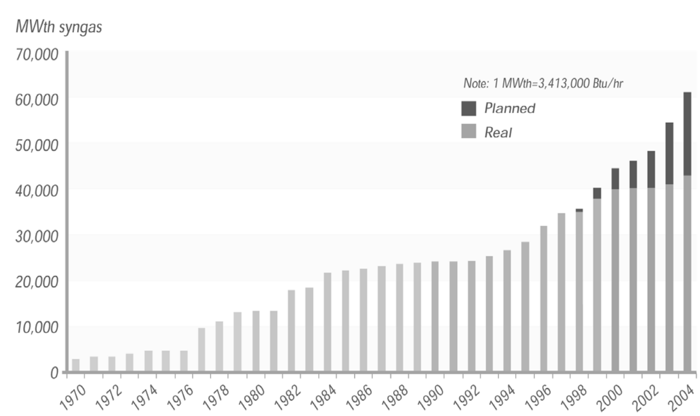
At the end of the demonstration in December 1999, Global Energy, Inc. purchased the gasification assets and technology from Dynegy. Global Energy is marketing the technology under the name E-Gas™. The project is continuing to operate in commercial service as Wabash River Energy, Ltd., a subsidiary of Global Energy.

The immediate future for E-Gas™ technology appears to lie with both foreign and domestic application where low-cost feedstocks such as petroleum coke can be used and co-production options are afforded — bundled production of steam, fuels, chemicals, and electricity. Integration or association with refinery operations are examples.

In the longer term, the technology has application for repowering the aging fleet of existing domestic coal-fired boilers, and new foreign and domestic coal-fueled capacity additions. Factors favoring increased use of IGCC over time are continued improvement in IGCC cost and performance, projected increases in price differentials between coal and gas, and continued importance placed on displacement of petroleum in chemicals and fuels production.

The potential sales of this technology are reflected in Figure 2, which is based on data developed by SFA Pacific, Inc. that shows the cumulative worldwide gasification capacity and growth.

Figure 2. Cumulative Worldwide Gasification Capacity And Growth



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