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and

Sunflower Electric Power Corporation

Holcomb Expansion Project Coal Technology Selection Study Update

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Acronym List

ACI	Activated Carbon Injection
AEP	American Electric Power
AFBC	Atmospheric Fluidized Bed Combustion
AGR	Acid Gas Removal
ASU	Air Separation Unit
BACT	Best Available Control Technology
BFB	Bubbling Fluidized Bed
Ca/S	Calcium to Sulfur
CaO	Calcium Oxide
CaS	Calcium Sulfide
CaSO ₄	Calcium Sulfate
CC	Combined Cycle
CCPI	Clean Coal Power Initiative
CCRB	Clean Coal Review Board
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
COP	ConocoPhillips
COS	Carbonyl Sulfide
CTG	Combustion Turbine Generator
DA	Deaerator
DLN	Dry-low NO _x
DOE	Department of Energy
EIS	Environmental Impact Statement
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
FBC	Fluidized Bed Combustion
FEED	Front End Engineering Design
FGD	Flue Gas Desulfurization
FWH	Feed Water Heater
GE	General Electric
GEC	Gasification Engineering Corporation
H ₂ S	Hydrogen Sulfide
H ₂ SO ₄	Sulfuric Acid
HCl	Hydrogen Chloride
HCN	Hydrogen Cyanide

Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
HRSG	Heat Recovery Steam Generator
HTHR	High Temperature Heat Recovery
IGCC	Integrated Gasification Combined Cycle
ISO	International Standards Organization
KBR	Kellogg Brown and Root
LHV	Lower Heating Value
LP	Low-Pressure
LSB	Last-Stage Blade
MDEA	Methyl Diethanol Amine
MHI	Mitsubishi Heavy Industries
N ₂	Nitrogen
NEPA	National Environmental Policy Act
NGCC	Natural Gas-fired Combined Cycle
NH ₃	Ammonia
NO _x	Oxides of Nitrogen
NPHR	Net Plant Heat Rate
O ₂	Oxygen
O&M	Operations and Maintenance
OUC	Orlando Utilities Commission
PC	Pulverized Coal
petcoke	Petroleum Coke
PM	Particulate Matter
PPA	Power Purchase Agreement
PRB	Powder River Basin
PSDF	Power Systems Development Facility
PUCO	Public Utilities Commission of Ohio
RFP	Request for Proposal
SCR	Selective Catalytic Reduction
SO ₂	Sulfur Dioxide
SNCR	Selective Noncatalytic Reduction
SPG	Siemens Power Generation
STG	Steam Turbine Generator
SPG	Siemens Power Generation
SWEPCO	Southwestern Electric Power Company

syngas	Synthetic Gas
TC	Tandem Compound
TRIG™	Transport Reactor Integrated Gasification
US	United States
VWO	Valves Wide Open
WHB	Waste Heat Boiler
ZLD	Zero Liquid Discharge
4F	Four-Flow

Units of Measure

¢	cents
\$	dollar
%	percent
° F	degrees Fahrenheit
Btu	British thermal unit
ft	foot
ft ³	cubic feet
h	hour
in. HgA	inches mercury absolute
kW	kilowatt
lb	pound
ltpd	long tons per day (2,200 lb/day)
m ³	cubic meters
MBtu	million British thermal unit
mg	milligrams
MW	megawatt
MWh	megawatt-hour
ppb	parts per billion
ppm	parts per million
ppmvd	parts per million volumetric dry
psia	pounds per square inch absolute
psig	pounds per square inch gauge
scf	standard cubic feet
sec	second
stpd	short tons per day (2,000 lb/day)
tpd	tons per day
yr	year

1.0 Executive Summary

Black & Veatch was retained to perform a coal technology selection study for the Holcomb Expansion Project (Expansion Project). The study compared subcritical and supercritical pulverized coal (PC), circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC) technologies. Performance and cost estimates were based on the use of Dry Fork Mine Powder River Basin (PRB) coal at the existing Holcomb plant site. A busbar economic analysis was also performed.

1.1 Conventional Coal Fired Technologies

Coal is the most widely used fuel for the production of power in the United States (US), and most coal burning power plants use PC boilers. PC units have the advantage of utilizing a proven technology with a high reliability level. PC units are relatively easy to operate and maintain. PC boilers are operating with steaming capacities sufficient to support up to 1,000 MW or more of electrical generation. For these larger units, economies of scale result in reduced busbar costs compared to smaller units. Realization of the economies of scale for PC boilers has led to the construction of units predominantly larger than 250 MW. These units can be designed to operate with supercritical steam conditions which improve overall plant efficiency and reduce fuel costs and the total mass of flue gas emissions compared to smaller subcritical units.

During the 1980s, fluidized bed combustion (FBC) emerged as a viable alternative to PC-fueled units for the combustion of solid fuels. FBC was applied to the electric utility industry because of its perceived air emission advantages over competing combustion technologies. Sulfur dioxide (SO₂) emissions could be controlled from FBC units without the use of external scrubbers, and oxides of nitrogen (NO_x) emissions from FBC units were inherently low. Furthermore, FBC units were touted as being “fuel flexible,” with the capability of firing a wide range of solid fuels with varying heating value, ash content, and moisture content. CFB boilers are the most common type of FBC for coal fired projects.

Even though CFB boilers have been providing steam for electric power generation for more than 20 years, the steaming capacities have been limited to less than 150 MW in most cases. Over the past decade, the offered capacity by CFB boiler vendors has increased. Both Foster Wheeler and Babcock & Wilcox now offer CFB boilers with capacities over 600 MW. To date, the largest CFB boiler to be constructed is the 460 MW unit supplied by Foster Wheeler for PKE - Elektrownia Lagisza in Lagisza, Poland. This CFB boiler is a supercritical reheat boiler and is currently under commissioning and is planned to fire bituminous coal and coal slurry as a primary and

secondary fuel, respectively. Several other CFB boilers in the 300 MW class have been developed over the past decade. Black & Veatch is aware of two new plants currently under construction in the U.S. Some of the earliest 300 MW class CFB boilers were installed at the JEA Northside Generating station in Northside, Florida. This unit consists of two 300 MW subcritical reheat CFB boilers. It has been in operation since 2001 and fires petroleum coke and bituminous coal as its primary and secondary fuels, respectively.

1.2 IGCC Technologies

The following sub-sections provide summary level descriptions of gasification and IGCC.

1.2.1 Gasification Process Description

Gasification consists of partially oxidizing a carbon containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a synthetic gas (syngas) consisting primarily of carbon monoxide (CO) and hydrogen. A small portion of the carbon is completely oxidized to carbon dioxide (CO₂) to generate sufficient heat for the endothermic gasification reactions. The gasifier operates in a reducing environment that converts most of the sulfur in the feed to hydrogen sulfide (H₂S). A small amount of the sulfur is converted to carbonyl sulfide (COS).

An IGCC plant typically includes an air separation unit (ASU) that cryogenically separates oxygen from nitrogen. The oxygen is used as the oxidant in the gasifier to produce low heating value gas (200 to 300 Btu/scf higher heating value [HHV]). High-pressure (HP) nitrogen from the ASU is used to dilute the syngas heating value to approximately 125 to 150 Btu/scf lower heating value (LHV) for NO_x control. Significant cleanup of the syngas is required before it enters the combustion turbine generator (CTG) combustor.

1.2.2 Gasification Technologies

Gasifier technologies are typically classified by their characteristic mode of fuel residence and include the following:

- Entrained flow gasifiers
- Fluid bed gasifiers
- Fixed bed (or moving bed) gasifiers

Entrained flow gasifiers have a residence time on the order of seconds, fluid bed gasifiers have a residence time on the order of minutes, and fixed bed gasifiers have a

residence time on the order of hours. At the present time, entrained flow gasifiers are generally considered to be the best choice for high capacity gasification to produce a syngas suitable for CTG fuel for power generation.

1.2.3 Gasification Suppliers

Until recently, there were three suppliers of utility scale, entrained flow gasification technologies.

- ConocoPhillips (COP), which licenses “E-Gas” (which was developed by Dow). COP purchased this technology from Global Energy in August 2003.
- General Electric (GE), which purchased Texaco gasification technology from ChevronTexaco in June 2004.
- Shell, which developed its gasification technology in conjunction with Uhde (formerly Krupp).

Since 2006, additional vendors that have entered the utility scale, entrained flow gasifier market including the following:

- MHI, which developed an air (oxygen enriched) gasifier specifically for IGCC applications. MHI has been operating an IGCC demonstration plant in Japan since 2007.
- PRENFLO, which was originally developed by Uhde. The PRENFLO technology is very similar to the Shell gasifier; Uhde and Shell worked together marketing the Shell gasifier between 1999 and 2009. Uhde has been marketing the PRENFLO gasifier since their agreement with Shell expired in 2009.
- Siemens, which purchased the Future Energy (Noell) gasifier technology in 2006.

The COP and GE gasifiers are refractory lined coal-water slurry feed. Shell, PRENFLO, and MHI all have water wall gasifiers that produce high pressure steam. Siemens has a water screen that can produce low pressure steam. Shell, PRENFLO, MHI, and Siemens are all dry feed technologies.

Coal-based IGCC projects using these gasification technologies are in various stages of development in the United States. As these projects progress, and as additional projects are announced, the engineering, procurement, and construction (EPC) terms and conditions may be developed. It is unlikely at the current level of gasifier technology development that an EPC contractor would provide an overall project guarantee which would “wrap” the supplied technology and equipment. In the current marketplace,

Owner's would be expected to supply their own contingency and assume some level of risk associated with the overall guarantees of the plant. In projects going forward into construction much of this contingency and risk is mitigated through co-funding by the United States Department of Energy (US DOE).

1.2.4 Effect of Fuel Characteristics on Gasifier Selection

There are three general coal feedstocks typically considered for domestic IGCC projects: Pittsburgh No. 8, Illinois No. 6, and PRB. Petcoke is a fourth solid fuel feedstock that is frequently considered for IGCC applications. Petcoke, as an opportunity fuel, can be a lower cost fuel, but it is not as readily obtainable as coal unless in the proximity of an oil refinery. Coal-based operating experience has been focused predominantly on bituminous coals; but there is also experience with sub-bituminous, lignite, and petcoke. Although the majority of sub-bituminous experience has been limited to the E-Gas (then Dow) gasification technology at the Louisiana Gasification Technologies Incorporated (LGTI) plant in Plaquemine Louisiana, the nature of the US coal market and the abundance of PRB coal naturally results in an interest in using PRB coals for IGCC using other developing gasification technologies.

All of the major gasification technologies can operate on bituminous coals and petcoke; Shell, PRENFLO, MHI, and Siemens gasification technologies would have a strong economic advantage over COP and GE when 100 percent PRB coal is used, because they dry the coal during milling. Therefore, the high moisture content of PRB does not affect gasifier performance. The COP and GE gasification technologies slurry the coal with water during milling to enable the gasifier fuel feed system. The heat required to evaporate this additional water in the gasifier is provided by combusting carbon in the coal to CO₂, which greatly reduces the heat value of the syngas. Because of the inherently low heating value of PRB coal, gasification technologies which slurry the coal such as COP and GE, may not be best suited technologies for gasifying PRB coal, though, it is technically feasible. COP has successfully demonstrated the gasification of PRB coal with their technology.

This study reviews the commercially available entrained flow gasification technologies. Since PRB will be the fuel for the Holcomb project, the cost and performance data developed for the more detailed comparison is based upon the Shell technology, which is representative of the drymilled gasification technologies.

1.2.5 IGCC Industry Activity

There have been approximately 18 IGCC projects completed throughout the world. Of these, ten were originally designed for coal, two for petcoke, and six for liquid fuels. Two of the coal-based IGCC plants, Cool Water in California and the LGTI Plant in Louisiana, were small demonstration projects and have been decommissioned. Another small coal IGCC demonstration project was Sierra Pacific's Piñon Pine Project in Nevada. This project, based on a fluid bed technology, was not successful. The Schwarze Pumpe plant in Germany operated for many years but was shut down in 2007 because of the large cost of its waste to methanol operation. The plant is expected to restart operation on lignite fuel.

Of the six operating coal IGCC plants, one is a 350 MW lignite cogeneration plant that has 26 Lurgi fixed bed gasifiers, and five are utility scale, entrained flow gasification demonstration projects, ranging in capacity from 250 to 300 MW and located in Florida, Indiana, The Netherlands, Spain, and Japan. Each of the five entrained flow gasification demonstration projects was a government-subsidized IGCC demonstration. Each of these IGCC plants consists of a single train (one ASU, one gasifier, one gas treating train, and one combined cycle (CC) composed of one CTG, one heat recovery steam generator (HRSG), and one steam turbine generator [STG]). Each plant experienced numerous problems during its first years of operation.

The operation of these five commercial coal-fueled IGCC plants has provided benchmarks for expected capacity, efficiency, and environmental performance. Uncertainty remains regarding plant availability and capital and operations and maintenance (O&M) costs. The complexity and relative immaturity of the IGCC process increases opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. Duke Energy is midway through the construction of an IGCC plant in Edwardsport, Indiana. The expected capacity of the plant is 618 MW (net). The plant is scheduled to reach mechanical completion in September, 2012.¹

¹ As access June 3, 2010 at
<http://www.powergenworldwide.com/index/display/articledisplay/9015885896/articles/powergenworldwide/coal-generation/new-projects/2010/04/edwardsport-igcc.html>

1.3 Technology Screening Performance and Cost Estimates

Black & Veatch developed performance and cost estimates of four baseload generation technology options. The performance and cost data were utilized in a busbar screening tool discussed in Section 5.0. For purposes of this evaluation, the technologies were evaluated on a consistent basis relative to each other. The following four baseload technologies were considered:

- Supercritical PC.
- Subcritical PC.
- CFB.
- IGCC.

The needs of the project require a net plant output of 895 MW (net) at the plant boundary at the hot day ambient condition. The PC and CFB options were configured to provide a net plant output of 895 MW net. The IGCC unit was configured to best satisfy this requirement without substantially exceeding a net plant output of 895 MW.

The cost estimates have assumed that this project would be an add-on unit at the existing Holcomb Station. A summary of the performance and cost estimates are shown in Table 1-1.

Table 1-1. Summary of Performance and Cost Estimates

	Supercritical PC	Subcritical PC	CFB	IGCC
Performance				
Hot Day Net Plant Output, kW	895,000	895,000	895,000	747,300
Average Day Net Plant Output, kW	903,900	901,900	901,900	800,900
Hot Day Net Plant Heat Rate, Btu/kWh (HHV)	9,089	9,325	9,442	9,014
Average Day Net Plant Heat Rate, Btu/kWh (HHV)	9,000	9,253	9,370	8,962
Annual Capacity Factor, percent	90	90	90	85
Annual Average Generation, GWh	7,126	7,111	7,111	5,964
Capital Cost				
EPC Cost, \$Million	1,941	1,888	2,128	2,760
EPC Cost, \$/kW	2,147	2,093	2,359	3,446
Owner's Cost, percent	35	35	35	41
Total Project Cost, \$Million	2,620	2,548	2,873	3,892
Total Project Cost, \$/kW	2,899	2,825	3,185	4,859
O&M Costs				
Fixed Costs, \$/kW	15.79	15.67	16.92	32.03
Nonfuel Variable Costs, \$/MWh	4.17	4.07	4.99	5.80
Note: Unit costs based on average day net plant output.				

1.4 Environmental Considerations

For the four technologies evaluated, expected emission rate performance is listed in Table 1-2. Final permit levels may vary on a case-by-case basis.

Table 1-2. Expected Emission Rate Performance			
	PC	CFB	IGCC
NO _x , lb/MBtu	0.05	0.07 – 0.09	0.01 – 0.02
SO ₂ , lb/MBtu	0.06	0.07 – 0.08	0.03 – 0.10
PM, lb/MBtu	0.012	0.010 – 0.015	0.007 – 0.011
Hg, lb/GWh	0.020	Note 5	Note 5
Notes: 1. PC values are consistent with recent Holcomb 2 proposed Air Emission Source Construction Permit. 2. CFB and IGCC indicative emissions limit ranges are representative of recent Best Available Control Technology and Maximum Achievable Control Technology. 3. MBtu on an HHV basis. 4. PM values are filterable. 5. As of June 2009, Mercury (Hg) limits have been removed from the EPA New Source Performance Standards (NSPS). This leaves the fate of Hg as a hazardous air pollutant (HAP) which is subject to a Maximum Available Control Technology review (MACT) at major sources of HAPs. Hg emissions limits are determined on a case by case basis during the permitting process. The proposed Supercritical PC for Holcomb 2 is not a major source of HAPs.			

1.5 Economic Analysis

A busbar analysis was developed to compare the four technologies. Key economic criteria utilized in the busbar evaluation are described below.

The total project cost includes both the EPC cost and the Owner’s costs. For this screening analysis, the Owner’s costs have been estimated as 35 percent of the EPC capital cost. For IGCC, an additional 6 percent Owner’s risk contingency was added to the Owner’s costs to account for issues in the first few years of operation, such as added personnel required for startup and commissioning, debottlenecking of processes, and streamlining operations.

Performance was based on the annual average day. The projected capacity factor for the PC and CFB unit is 90 percent. The projected long term capacity factor for the IGCC unit is 85 percent. Natural gas back-up was assumed during the first three year of operation of the IGCC unit to maintain an annual capacity factor of 85 percent.

Fuel forecasts for PRB coal for a western Kansas site were developed and are provided in Table 5-2. A present worth discount rate of 8.5 percent and a levelized fixed charge rate of 10.5 percent were used for the analysis. The results are presented in Table 1-3. The results are also presented graphically in Figure 1-1.

Table 1-3. Busbar Results			
Case	Description	30-Year Levelized Busbar Cost, ¢/kWh	30-Year Levelized Annual Cost, \$1,000,000
1	Supercritical PC	6.07	432.4
2	Subcritical PC	5.99	426.1
3	CFB	6.63	471.7
4	IGCC	9.73	580.5

Results are based on economic criteria from Table 5-1, fuel forecasts from Table 5-2, and the inputs from Table 5-3.

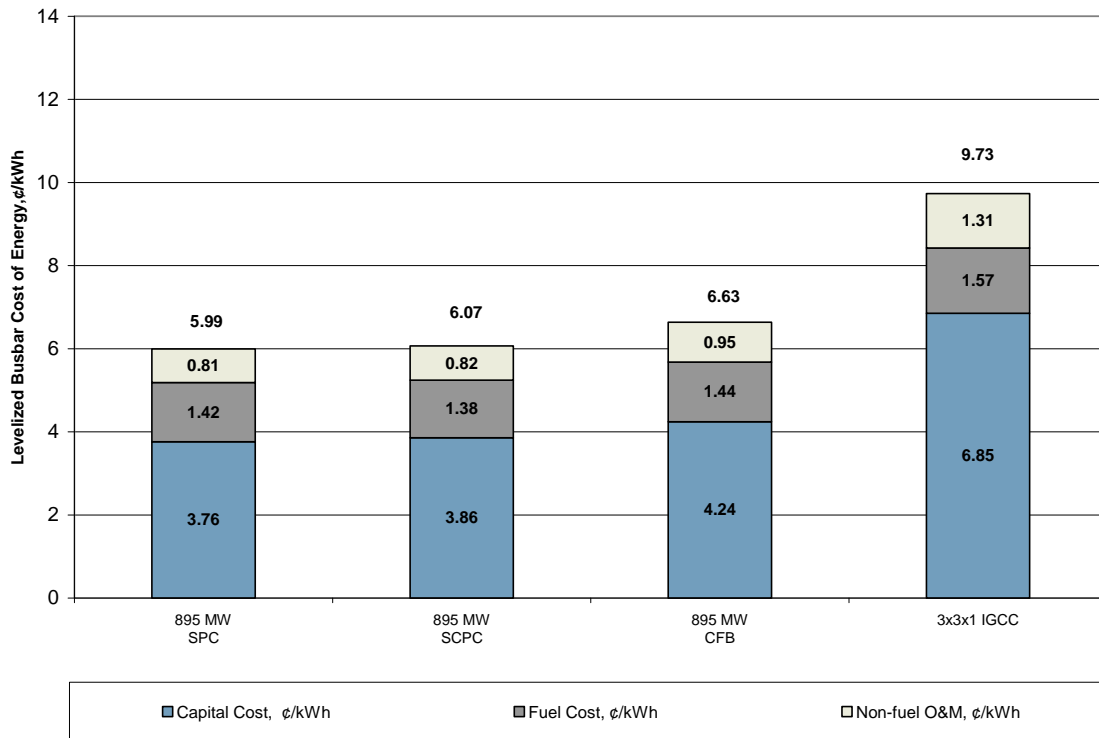


Figure 1-1. Levelized Busbar Cost Comparison

1.6 Conclusions

The economic analysis, as provided in Table 1-3, indicates the lowest cost technologies are the conventional PC and CFB units. The IGCC levelized busbar cost is roughly 50 percent higher than those of the PC and CFB. The costs of emission allowances were not included in the busbar cost analysis.

IGCC is not economically competitive with PC. The limited commercial and operational experience of IGCC would make it a substantial operational and commercial risk as a generating technology for the Expansion Project. IGCC, therefore, is not a practical alternative for the Expansion Project.

The other two technologies evaluated, PC (either super or subcritical) and CFB, are commercially available for consideration for a new 895 MW coal-fired generating facility at Holcomb. The emissions of regulated pollutants from these two technologies are very similar. The most fuel efficient technology is supercritical PC, whose heat rate is approximately three percent better than the subcritical and CFB technologies. CFB is expected to be slightly more expensive, as measured by the levelized busbar cost of power, than PC.

Within the accuracy of the evaluation, the subcritical and supercritical PCs are assumed to be equivalent. Supercritical PC is more efficient than the subcritical PC, which reduces the coal consumption by roughly 2.5 percent which directly reduces the total mass of the flue gas emissions by comparison.

2.0 Conventional Coal Fired Technologies (PC and CFB)

This section contains a summary-level comparison of CFB and PC technologies, along with a review of CFB experience in the United States, and a discussion of the issues related to scaling-up CFB unit sizes.

The function of a steam generator is to provide controlled release of heat from the fuel and efficient transfer of heat to the feedwater and steam. The transfer of heat produces main steam at the pressure and temperature required by the HP turbine. Conventional coal fired steam generator design has evolved into two basic combustion and heat transfer technologies. Suspension firing of coal in a PC unit and combustion of crushed coal in a CFB unit are the predominant coal fired technologies in operation today for larger utility scale applications.

2.1 Pulverized Coal

Coal is the most widely used fuel for the production of power in the US, and most coal-burning power plants use PC boilers. PC units have the advantage of utilizing a proven technology with a high reliability. These units can be very large, up to 1,000 MW or more, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain.

New generation PC boilers can be designed at supercritical steam pressures of 3,600 to 4,500 psig, compared to the steam pressure of 2,400 psig for conventional subcritical boilers. The increase in pressure from subcritical to supercritical pressure can decrease the net plant heat rate over 2 percent. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, expected unit capacity factor, environmental factors, and the cost of capital.

With PC technology, coal that is sized to roughly 20 mm top size is fed to the pulverizers, which finely grind the coal to a size of no less than 70 percent through a 200 mesh screen (70 microns). This pulverized coal is conveyed to the coal burners suspended in the primary air stream. At the burner, this mixture of primary air and coal is further mixed with secondary air and, with the presence of sufficient heat for ignition, the coal burns in suspension with the expectation that combustion will be complete before the burner flame contacts the back wall or side walls of the furnace. Current pulverized fuel combustion technology also includes features to minimize unintended products of combustion, such as NO_x and other air toxics such as CO.

Because of the high combustion temperature of PC at the burners, the furnace enclosure is constructed of membrane waterwalls to absorb the radiant heat of

combustion. This heat absorption in the furnace is used to evaporate the preheated boiler feedwater that is circulated through the membrane furnace walls. The steam from the evaporated feedwater is separated from the liquid feedwater and routed to additional heat transfer surfaces in the steam generator. Once the products of coal combustion (ash and flue gas) have been cooled sufficiently by the waterwall surfaces so that the ash is no longer molten but is in a solid and non-tacky form, heat transfer surfaces, predominantly of the convective type, absorb the remaining heat of combustion. These convective heat transfer surfaces are the superheaters, reheaters, and economizers located within the steam generator enclosure downstream of the furnace. The final section of boiler heat recovery is in the air preheater, where the flue gas leaving the economizer surface is further cooled by regenerative or recuperative heat transfer to the incoming combustion air.

Though the steam generating surfaces are designed to preclude the deposition of molten or sticky ash products, on-line cleaning systems are provided to enable the removal of ash deposits as they occur. These on-line cleaners are typically soot blowers that utilize either HP steam or air to dislodge ash deposits from heat transfer surfaces or, in cases with extreme ash deposition, utilize high pressure water to remove molten ash deposits from evaporative steam generator surfaces. The characteristics of the coal, such as ash content and the ash chemical composition, dictate the type, quantity, and frequency of use of these on-line ash cleaning systems. Ash characteristics also dictate steam generator design regarding the maximum flue gas temperatures that can be tolerated entering convective heat transfer surfaces. The design must ensure that ash in the flue gas stream has been sufficiently cooled so that it will not rapidly agglomerate or bond to convective heat transfer surfaces. For very hard and erosive ash components, the flue gas velocities must be sufficiently slow so that the ash will not rapidly erode heat transfer surfaces.

With PC combustion technology, the majority of the solid ash components in the coal will be carried in the flue gas stream all the way through the furnace and convective heat transfer components so that they may be collected by particulate removal equipment downstream of the air preheaters. Typically, no less than 80 percent of the total ash will be carried out of the steam generator for collection downstream. Approximately 15 percent of the total fuel ash is collected from the furnace hopper (bottom ash), and 5 percent is collected in hoppers located below the steam generator economizer and regenerative air heaters.

2.2 Fluidized Bed

During the 1980s, FBC emerged as a viable alternative to PC-fueled units for the combustion of solid fuels. Initially used in the chemical and process industries, FBC was applied to the electric utility industry because of its perceived air emissions advantages over competing combustion technologies. Also, FBC units tend to be “fuel flexible,” with the capability of firing a wider range of solid fuels with varying heating value, ash content, and moisture content compared to PC boilers. Slagging and fouling tendencies were minimized in the FBC units because of low combustion temperatures.

The most common type of FBC boiler is the atmospheric FBC which is generally divided into two categories: bubbling fluidized bed (BFB) and circulating fluidized bed (CFB).

A CFB operates at higher bed fluidizing velocities than a BFB and has better environmental characteristics and higher efficiency than BFB. A CFB boiler is generally the FBC technology of choice for fossil fuel applications greater than 50 MW and is the primary coal fired boiler alternative to a PC boiler

In a CFB unit, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water-cooled membrane walls with specially designed air nozzles that distribute the air uniformly. The fuel and limestone are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. Staged combustion and low combustion temperature limit the formation of thermal NO_x.

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed and, thus, fluidizing air carries the particles through the combustion chamber to the particulate separators at the furnace exit. The captured solids, including any unburned carbon and unused calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal solids circulation provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

Commercial CFB units offer greater fuel diversity than PC units, operate at competitive efficiencies, and, when coupled with a polishing SO₂ scrubber, operate with emissions at or below the current levels mandated by federal standards.

By the late 1980s, the transition had been made from small industrial sized boilers to several electrical utility reheat boilers in operation in a size range from 75 to 165 MW. Several reheat boilers up to 300 MW are currently in service, and boiler suppliers are

offering boiler designs to provide steam generation sufficient to support up to 600 MW, with commercial guarantees.² Fuels for these applications range from petcoke and bituminous coal to high ash refuse from bituminous coal preparation and cleaning plants, and high moisture fuels such as lignite. Some units were installed to utilize the tailings and washing residue from early anthracite mining operations.

A feature of CFB is that a portion of the SO₂ can be removed in the combustion process by adding limestone to the fluidized bed. The CaO formed from the calcination of limestone reacts with SO₂ to form calcium sulfate (CaSO₄), which is removed from the flue gas with a conventional particulate removal device. CFB combustion temperature is controlled at approximately 1,600° F, compared to approximately 2,500 to 3,000° F for conventional PC boilers. Combustion at the lower temperature has several benefits. First, the lower temperature minimizes the sorbent (typically limestone) requirement, because the required calcium to sulfur (Ca/S) molar ratio for a given SO₂ removal efficiency is minimized in this temperature range. Second, 1,550 to 1,600° F is well below the ash fusion temperatures of most fuels, so the fuel ash never reaches its softening or melting points. The slagging and fouling problems that are characteristic of PC units are significantly reduced, if not eliminated. Finally, the lower temperature reduces NO_x emissions by nearly eliminating thermal NO_x. Figure 2-1 illustrates the benefits of a lower combustion temperature for CFBs.

Because combustion temperatures are below ash fusion temperatures, the design of a CFB boiler is not as dependent on ash properties as is a conventional PC boiler. With proper design considerations, a CFB boiler can fire a wider range of fuels with less operating difficulty.

The fuel size for a CFB boiler is much coarser than the pulverized fuel needed for suspension firing in a PC boiler. Compared to the typical 70 micron particle size for a PC unit, the typical fuel size for a CFB is approximately 5,000 microns. For high ash fuels, the use of larger fuel sizing reduces auxiliary power and pulverizer maintenance requirements and eliminates the high cost of pulverizer installation.

² For the purpose of this study, a 3x300 MW boiler configuration has been assumed.

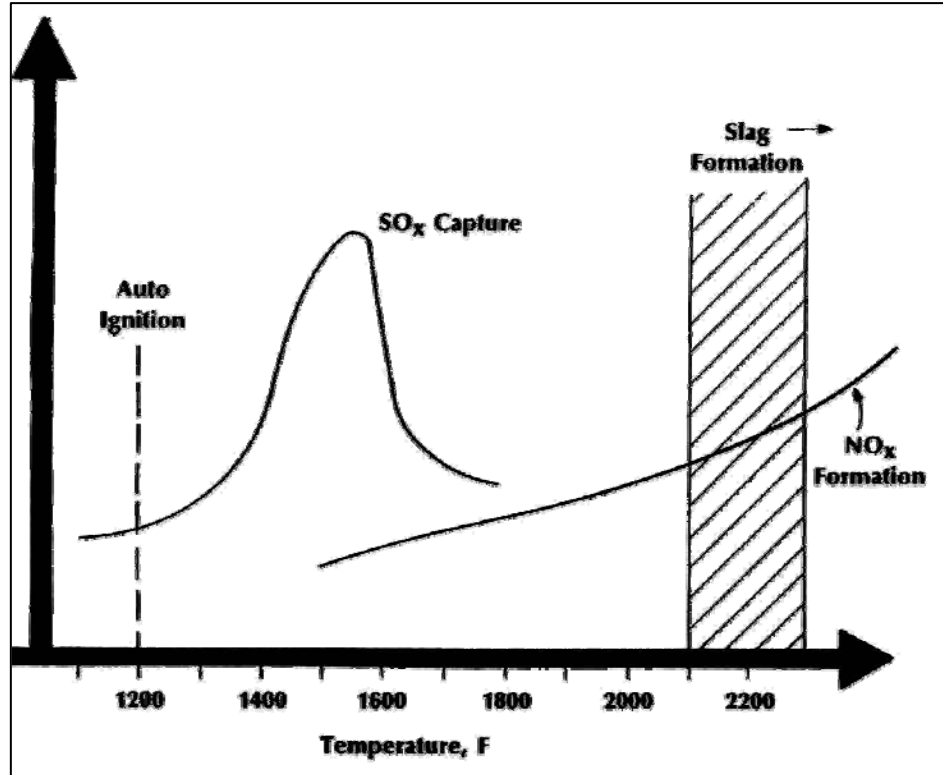


Figure 2-1. Environmental Benefits of CFB Technology

Even though CFB boilers have been providing steam for reheat turbine electric power generation for more than 20 years, the steaming capacities have been limited to less than 150 MW in most cases due to difficulties in obtaining even distribution of the fuel and limestone in the bed of the CFB. However, over the past decade, the offered capacity by CFB boiler vendors has dramatically increased. Both Foster Wheeler and Babcock & Wilcox now offer CFB boilers with capacities over 600 MW. To date, the largest CFB boiler to be constructed is the supercritical, reheat 460 MW unit supplied by Foster Wheeler for PKE - Elektrownia Lagisza in Lagisza Poland. This project is currently under start-up and is planned to fire Polish bituminous coal and coal slurry as primary and secondary fuels, respectively.³ Several other CFB boilers in the 300 MW class have been developed over the past decade and several more are currently under construction and start-up. Some of the earliest 300 MW class CFB boilers were installed at the JEA Northside Generating station in Northside, Florida. This unit consists of two 300 MW subcritical reheat CFB boilers. It has been in operation since 2001 and fires petroleum coke and bituminous coal as its primary and secondary fuels, respectively.

³ Foster Wheeler, available at: <http://www.fwc.com/>

3.0 IGCC Technologies and Industry Activity

IGCC is an alternative to PC and CFB for coal-based electricity generation, although there is comparatively little commercial experience to date.

In the near term, reliability is expected to be lower for an IGCC plant than for a PC or CFB plant with respect to producing electricity from coal. IGCC plants are expected to achieve long-term annual availabilities in the 80 to 85 percent range on coal, unless equipped with a spare gasifier or natural gas back-up. By comparison, a well-operated PC or CFB plant can achieve availabilities of approximately 90 percent. IGCC availability on coal during initial startup and the first several years of operation is expected to be significantly lower.

Cost, schedule, and plant availability issues cause IGCC projects to have higher financial risk than conventional PC or CFB power generation projects. Details regarding the guarantee levels for cost, schedule, and performance; the associated liquidated damages clauses and risk premium; and availability assurances are not well defined and IGCC projects could be challenging to finance in the near term.

3.1 Gasifier Technologies

Gasification is a technology with a history that dates back to the 1800s. The first patent was granted to Lurgi GmbH in Germany in 1887. By 1930, coal gasification had become widespread, and, in the 1940s, commercial coal gasification was used to provide “town” gas for streetlights in both Europe and the United States. Gasifier technologies are typically classified by their characteristic mode of fuel residence and include the following:

- Entrained flow
- Fluid bed
- Fixed bed

Entrained flow gasifiers have a residence time on the order of seconds, fluid bed gasifiers have a residence time on the order of minutes, and fixed bed gasifiers have a residence time on the order of hours. Table 3-1 summarizes key characteristic differences for the three main types of gasifier technologies compared to entrained flow gasifiers.

Entrained flow gasifiers have been operating on solid fuels since the mid-1980s to produce chemicals and, since the mid-1990s, to produce electricity. At this time, based upon their characteristics and level of development, entrained flow gasifiers are the best choice for high capacity gasification for power generation. The following sections

provide more in-depth descriptions for entrained flow gasifiers and entrained flow gasifier technology suppliers.

Table 3-1. Gasifier Technologies

	Entrained Flow	Fixed Bed	Fluid Bed
Maturity	Since the 1920s on liquid fuels and since the 1980s on solid feedstock	Since the 1940s on solid feedstock	Since the 1920s on solid feedstock
Operational Pressure	High	Lower	Lower
Operation Temperature	High	Lower	Lower
Oxidant, typical	Purified oxygen	Purified oxygen	Air
Fuel Residence Time	Very low	Much longer	Much longer
Capacity	High	Lower	Lower
Sulfur Control	Post gasification removal	Post gasification removal.	Gasifier injected limestone sorbent
Sulfur Control Byproduct	Marketable elemental sulfur	Marketable elemental sulfur.	Disposable (landfill) CaSO ₄
Ash / Slag	Operates above the ash fusion temperature and produces a non-leachable slag that can be sold	Dry bottom fixed bed--Ash is leachable and typically landfilled. Slagging fixed bed-- Operates above the ash fusion temperature and produces a non-leachable slag that can be sold.	Leachable and typically landfilled

3.2 Entrained Flow Gasifiers

The following list includes the most notable entrained flow gasifier technology suppliers:

- COP (E-Gas, formerly Global Energy, originally Dow-Destec).
- GE (formerly ChevronTexaco, originally Texaco).
- Mitsubishi Heavy Industries (MHI)
- Shell.
- Siemens.
- Uhde (PRENFLO).

A schematic for an IGCC unit utilizing an entrained flow gasifier is shown in Figure 3-1.

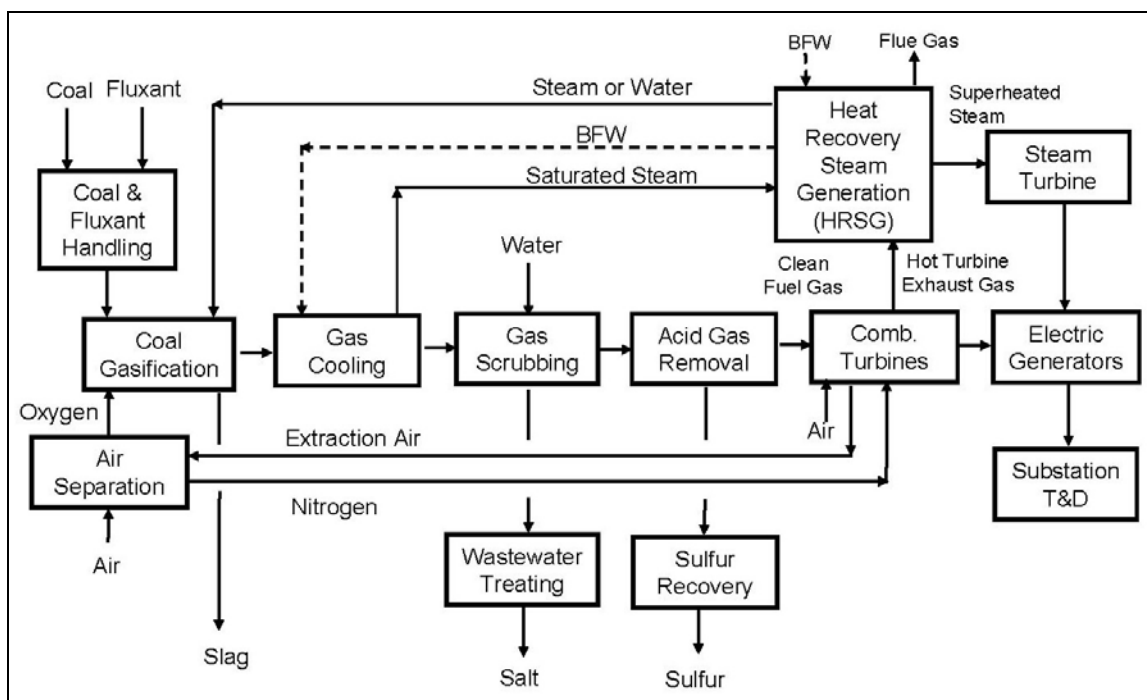


Figure 3-1. IGCC Process Flow Diagram

Gasification consists of partially oxidizing a carbon-containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to CO₂ to generate sufficient heat for the endothermic gasification reactions. The CO₂ proportion in the syngas from the gasifier ranges from one percent for the dry feed gasifiers (MHI, Shell,

Siemens and Uhde) to more than 15 percent for the slurry feed COP and GE gasifiers. The gasifier operates in a reducing environment that converts most of the sulfur in the feed to hydrogen sulfide (H₂S). A small amount of sulfur is converted to carbonyl sulfide (COS). Other minor syngas constituents include ammonia (NH₃), hydrogen cyanide (HCN), hydrogen chloride (HCl), and entrained ash, which contains unconverted carbon. In IGCC applications, the gasifier pressure is typically 450 to 550 psig. This pressure is determined by the CTG syngas supply pressure requirements. GE gasifiers operate at higher pressures, up to 1,000 psig, and the excess syngas pressure is let down in an expander to produce additional power.

A fluxant is fed with the coal to control the slag viscosity so that it will flow out of the gasifier. Fluxant addition is less than 2 percent of the coal feed. The fluxant is typically limestone, but PC boiler ash can also be used. The required fluxant composition and proportion will vary with the coal feed composition. The gasification process operators must know the feed coal composition and make fluxant adjustments when the coal composition changes. Too little fluxant can allow excessive slag to accumulate in the gasifier, which could damage the refractory and eventually choke the gasifier. Too much fluxant can produce long cylindrical slag particles instead of small slag granules when the slag is quenched in the lockhopper. These long thin slag particles will plug up the slag lockhopper.

Solid fuel feeds to the gasifier can be dry or slurried. Solid fuels slurried in water do not require the addition of steam for temperature moderation. While slurries typically use water, oil can also be used. Steam is added to the oxygen as a temperature moderator for dry solid feed gasifiers, solid feeds slurried in oil, and oil feed gasifiers.

Entrained flow gasifiers use oxygen to produce syngas heating values in the range of 250 to 300 Btu/scf on an HHV basis. An oxygen concentration of 95 percent by volume is the economic optimum for IGCC plants using entrained flow gasifiers that only produce power. (Higher oxygen concentrations are optimum when most of the syngas is used to produce hydrogen.) Oxygen is produced cryogenically by compressing air, cooling and drying the air, removing CO₂ from the air, chilling the feed air with product oxygen and nitrogen, reducing the air pressure to provide autorefrigeration and liquefy the air at -300° F, and separating the liquid oxygen and liquid nitrogen by distillation. Air compression consumes a significant amount of power, between 13 and 17 percent of the IGCC gross power output.

The raw hot syngas is cooled by boiler feedwater to a temperature suitable for cleaning. The syngas cooling process generates saturated steam that can be superheated in the HRSG and integrated into the steam cycle. The steam quantities and pressures vary with the gasification process design.

Before raw syngas enters the CTG combustor, the H₂S, COS, NH₃, HCN, and particulates must be removed. Cooled syngas is scrubbed to remove NH₃, water soluble salts, and particulates. Syngas may also be filtered to remove additional particulates. COS in the syngas is hydrolyzed by a catalyst to H₂S, which is removed from the syngas by absorption in a solvent. This absorption process is called acid gas removal (AGR).

Syngas is filtered in ceramic candle filters at the Buggenum and Puertollano IGCC plants. At the Wabash IGCC plant, syngas was initially filtered in ceramic candle filters; later, the filter elements (candles) were changed to sintered metal. The syngas filters at Buggenum, Puertollano, and Wabash are located upstream of the AGR. At the Polk County IGCC plant, particulate is removed from the syngas in a syngas scrubber by intimate contact with water.

The H₂S that is removed from the syngas by absorption in a solvent is desorbed as a concentrated acid gas when the solvent is regenerated by lowering its pressure and increasing its temperature. Descriptions of commercial AGR systems are provided in Section 3.9. The acid gas stream can be converted to either elemental sulfur in the Claus sulfur recovery process or sulfuric acid in a wet sulfuric acid process.

The primary chemical reaction in the Claus process is the reaction of H₂S and SO₂ to produce elemental sulfur and water. This reaction requires a catalyst and is performed in two stages. The SO₂ is produced by oxidizing (burning) one third of the H₂S in the feed gas. External fuel is only needed to initially heat up the Claus thermal reactor and initiate combustion of the acid gas. Under normal operation, the oxidation of H₂S provides sufficient heat to maintain the reaction. The sulfur is formed as a vapor. The S₂ form of sulfur reacts with itself to produce S₆ and S₈, which are subsequently condensed. This condensed liquid sulfur is separated from the residual gas and stored in a pit at 275 to 300° F. As required, the liquid sulfur is pumped from the pit to railcars for shipment. Solid sulfur can be produced in blocks or pellets by cooling the liquid sulfur to ambient temperature. The residual (tail gas) is primarily CO₂ and nitrogen, which are compressed and reinjected into the syngas upstream of the AGR.

In the wet sulfuric acid process a portion of the sour acid gas from the AGR is combusted to form SO₂ and the hot combustion products are cooled in a Waste Heat Boiler. One advantage of doing this is that the exothermal heat from combustion and the sulfuric acid reactions can be recovered as superheated steam and used internally in the steam cycle resulting in an overall more efficient plant. The cooled combustion products are passed to an SO₂ Oxidation Reactor, where the SO₂ is catalytically converted to SO₃. The oxidation reaction is exothermic and the reaction heat can be recovered in heat exchangers to produce superheated high pressure steam. The cooled gas leaves the heat

exchanger and is introduced in the bottom part of the condenser where ambient air is used to condense the sulfuric acid.

Hydrogen in syngas prevents the use of dry low NO_x (DLN) combustors in the CTGs. Dilution of the syngas to reduce flame temperature is required for NO_x control. Syngas can be diluted by adding water vapor and/or nitrogen. Water vapor can be added to the syngas by evaporating water using low level heat. Nitrogen can be added by compressing excess nitrogen from the ASU and adding it to the syngas, either upstream of the CTG or by injection into the CTG. Syngas dilution for NO_x control increases the mass flow through the CTG, which also increases power output.

3.3 Entrained Flow Gasifier Technology Suppliers

Although there have been relatively few major players in the recent past for the large scale, solid fuel, gasifier market, the number of established vendors has increased. The level and type of experience (e.g. IGCC, chemicals) varies among technology suppliers. The following major technology suppliers have expressed their interest in the ongoing development of IGCC projects:

- COP, which licenses E-Gas technology that was developed by Dow. COP purchased this technology from Global Energy in August 2003.
- GE, which purchased Texaco gasification technology from ChevronTexaco in June 2004. GE offers both Quench and Radiant (high temperature heat recovery [HTHR]) cooler gasifiers.
- MHI, which is an air blown (oxygen enriched), dry feed gasifier that is being developed specifically for IGCC applications.
- Shell, which developed its gasification technology in conjunction with PRENFLO.
- Uhde, which recently re-entered the gasifier vendor market after their agreement with Shell was not renewed toward the end of 2008.
- Siemens, which purchased the Future Energy (Noell) gasifier technology in 2006. The Siemens gasifier uses a full spray quench configuration, but is developing a partial water quench for IGCC applications.

Although there are other gasifier vendors, Black & Veatch believes the six indicated above are those likely to be selected for most IGCC applications.

The COP and GE gasifiers are refractory lined with coal-water slurry feed. The GE quench gasifier is used extensively in chemical plants around the world. GE has been expanding their commercial offering to larger scales to meet demand for larger chemical

plants and large scale IGCC plants. COP has significantly less experience than GE, but is one of the only gasifiers with a demonstration scale IGCC plant operating on solid fuel.

Shell and Krupp-Koppers (now Uhde) jointly developed a waterwall type gasifier with dry, PC feed specifically for IGCC power generation in the late 1970s for a 150 long tons per day (ltpd) demonstration plant near Hamburg, West Germany. During the 1990s, Shell and Krupp-Koppers licensed their gasification technology separately. The Puertollano, Spain IGCC plant, which was built in the mid-1990s, uses Krupp-Kopper's PRENFLO gasification technology. In the late 1990s, Krupp-Koppers merged with Uhde; Uhde reached an agreement with Shell to license Shell gasification technology. In 2008 Uhde did not renew their agreement with Shell and now commercially offers the PRENFLO gasifier.

Siemens and MHI are relatively new to the utility scale solid fuel gasification market. Siemens purchased their gasification technology from Future Energy in 2006. The technology was developed at the Deutche Brennerstoff Institute (DBI) and was owned and developed by several companies before Future Energy. Siemens has been aggressively marketing their technology for chemicals and substitute natural gas applications, but is also interested in the IGCC market. In contrast, MHI is focused almost entirely on the IGCC market and has developed their technology with that in mind. MHI is not an oxygen blown gasifier, but does use an ASU to supply nitrogen for its dry feed process to the gasifier. The oxygen produced in the ASU is used to enrich the air used in the gasification process. MHI developed a 250 MW IGCC plant (Nakoso) in Iwaki City, Japan that began construction in 2004 and was completed in 2007. The plant has completed several thousand hours of operation to date.⁴

With the exception of the MHI gasifier, each of the commercial entrained flow coal gasification technologies generates similar syngas products. The gasifiers react the coal with oxygen and water at high pressure and high temperature to produce syngas consisting primarily of hydrogen and CO. The raw syngas from the gasifier also contains CO₂, water, H₂S, COS, NH₃, HCN, and other trace impurities (the MHI gasifier also has significant quantities of N₂). The syngas exits the gasifier reactor at approximately 2,500 to 2,900° F.

⁴ Yoshitaka Ishibashi, "Second Year Operation Results of CCP's Nakoso 250MW Air-blown IGCC Demonstration Plant." Gasification Technologies Conference 2009, October 6, 2009

Each of the gasification processes cools the hot syngas from the gasifier reactor differently. In the COP process, the hot syngas is partially quenched with coal slurry, resulting in a second stage of coal gasification. The chemically quenched syngas is further cooled to produce steam in a fired tube heat exchanger. (Syngas flow is through the tubes. Boiler water and steam flow is through the shell side.) Unconverted coal is filtered from the cooled syngas and recycled to the gasifier first stage. GE has two methods for cooling the hot syngas from the gasifier: radiant cooling to produce HP steam via HTHR and water quench followed by low-pressure (LP) steam generation. The MHI gasifier uses a chemical quench cooling similar to COP, but with a dry feed, followed by a water tube convective syngas cooler that produces HP steam for the steam turbine. In the Shell process, hot syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled in a convective cooler to produce high temperature steam. The Siemens gasifier uses a water spray to quench the syngas to saturation conditions. Although they are developing a partial water quench with subsequent heat recovery, the lack of steam generation explains in part Siemens' focus on chemical plants rather than power generation.

The cooled, raw syngas is cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion, and scrubbing with solvents. The clean syngas that is used as CTG fuel contains hydrogen, CO, CO₂, water, and parts per million (ppm) concentrations of H₂S and COS.

3.4 Gasifier Technology Comparison

Table 3-2 provides process design characteristic data for the COP, GE, Shell, Siemens, MHI, and PRENFLO gasification technologies for systems that would be applicable for a utility scale IGCC. Overall, energy conversion efficiencies for IGCC plants vary with the gasification technology type, system design, level of integration, and coal composition. The gasifier efficiency of converting the coal fuel value to the syngas fuel value, after sulfur removal, is known as the cold gas efficiency, which is generally expressed in HHV. The values for cold gas efficiency in Table 3-2 are indicative of the range of achievable performance for coal and petcoke. The Shell, Siemens, and PRENFLO gasification technologies have the highest cold gas efficiencies, because the gasifier feed coal is injected into the gasifier dry. The COP and GE gasifiers use a coal and water slurry for the fuel feed. The Shell and PRENFLO dry feed coal gasification processes have higher capital costs. The MHI gasifier has a lower cold gas efficiency than the other dry feed gasifiers because of the nitrogen in the air used for gasification.

Cooling the hot syngas to produce HP steam contributes to higher IGCC efficiency, but with a higher capital cost. Shell, PRENFLO, MHI, and COP generate HP

steam from syngas cooling. GE offers both HP steam generation using a radiant syngas cooler and LP steam generation using its quench process, which has a significantly lower capital cost. Siemens is developing a partial water quench; when complete it should also be able to produce high pressure steam from the syngas cooling process.⁵

The COP and GE gasifiers are refractory lined, while the Shell, PRENFLO, and MHI gasifiers have an inner water tube wall (membrane). Siemens uses a water screen that produces small quantities of low to medium pressure steam. The refractory lined gasifiers have a lower capital cost, but the refractory requires frequent repair and replacement. The COP and GE gasifier burners typically require more frequent replacement than the Shell gasifier burners.

It is notable that gasifier sizing issues exist with respect to the different gasifier technologies. Shell has stated that its maximum gasifier capacity is 5,000 short tons per day (stpd) of dried coal, which is large enough to supply syngas to two GE 7F-Syngas (SG) or Siemens SGT6-5000F CTGs. Black & Veatch expects that the Uhde will offer similar PRENFLO sizes. GE offers gasifiers in three standard sizes: 750, 900, and 1,800 ft³. GE added the 1,800 ft³ gasifier in quench mode to their commercial offering in 2008. The 1,800 ft³ gasifier in radiant mode has been available since about 1996. The 1,800 ft³ radiant GE gasifier will supply sufficient syngas for a GE 7F-SG or Siemens SGT6-5000F CTG. COP currently offers a gasifier that will supply sufficient syngas for a GE 7F-SG or Siemens SGT6-5000F CTG. Siemens offers their gasifier in sizes of 500 and 1,200 MW_{th} thermal. The 1,200 MW_{th} gasifier is large enough to supply syngas to one advanced F class turbine. Black & Veatch is not aware of MHI's commercial offering plans.

⁵ Harry Morehead, "Siemens – US DOE Advanced H2 Turbine Program Technology Development is Key to Meeting Program Goals." Gasification Technology Conference 2008, October 7, 2008.

Table 3-2. Comparison of Key Gasifier Design Parameters

	COP	GE Quench	GE Radiant	Shell	Siemens	MHI	PRENFLO
Gasifier Feed Type	Slurry	Slurry	Slurry	Dry N ₂ Carrier	Dry N ₂ Carrier	Dry N ₂ Carrier	Dry N ₂ Carrier
Gasifier Burners	Two-Stage: First Stage--Two horizontal burners Second Stage--One horizontal feed injector without O ₂	Single-Stage--One vertical burner	Single-Stage--One vertical burner	Single-Stage--Four to eight horizontal burners	Single-Stage--One or more vertical burners	Two Stage: First Stage--Two horizontal burners Second Stage--One horizontal injector	Single-Stage--Four horizontal burners
Gasifier Vessel	Refractory lined	Refractory lined	Refractory lined	Waterwall membrane	Water screen	Water Wall membrane	Water Wall membrane
Syngas Quench	Coal slurry and recycle gas	Water Bath	None	Recycle gas	Water Spray	Chemical	Recycle gas
Syngas Heat Recovery	Firetube HP waste heat boiler (WHB)	Quench LP WHB	Radiant HP WHB	Watertube HP WHB	Quench LP WHB	Watertube HP WHB	Watertube HP WHB
Coal Cold Gas Efficiency, HHV	71 to 80 percent	69 to 77 percent	69 to 77 percent	78 to 83 percent	78 to 83 percent	70 to 75 percent	78 to 83 percent
Coal Flexibility	Middle	Low	Low	High	High	High	High
Capacity, stpd	3,000 to 3,500	1,500 to 2,000	2,500 to 3,000	4,000 to 5,000	1,500 to 4,000	1,700 ⁽¹⁾	2,500 to 4,000

Note:

1. Demonstrated capacity (Nakoso), Black & Veatch is not aware of MHI's commercial offering plans.

3.5 Commercial IGCC Experience

There have been approximately 18 IGCC projects completed throughout the world, as listed in Table 3-3. Of these, 16 are based on entrained flow gasification technology. Ten of the projects were originally designed for coal, two for petcoke, and the other six for liquid fuels. Two of the coal-based IGCC plants, Cool Water in California and LGTI in Louisiana, were small demonstration projects and have been decommissioned. Another small coal IGCC demonstration project was Sierra Pacific's Piñon Pine Project in Nevada. This project, based on KRW fluid bed technology, was not successful. The Schwarze Pumpe plant in Germany operated for many years but was shut down in 2007 because of the large cost of its waste to methanol operation. The plant is expected to restart on lignite fuel. To Black & Veatch's knowledge, there are currently thirteen operating IGCC plants.

Table 3-3. IGCC Projects--All Fuels

Owner--Location	Year ⁽¹⁾	MW	Application	Design Fuel ⁽²⁾	Gasifier
SCE Cool Water ⁽³⁾ --US (CA)	1984	120	Electric Power Generation	Bituminous Coal	Texaco (GE)
Dow LGTI Plaquemine ⁽³⁾ --US (LA)	1987	160	Cogen	Sub-bituminous Coal	Destec (COP)
Nuon Power--Netherlands	1994	250	Electric Power Generation	Australian Bituminous Coal	Shell
PSI/Global Wabash--US (IN)	1995	260	Repower	Bituminous Coal/ Petcoke	E-Gas (COP)
TECO Polk County--US (FL)	1996	250	Electric Power Generation	Bituminous Coal	Texaco (GE)
Texaco El Dorado ⁽⁴⁾ --US (KS)	1996	40	Cogen	Petcoke	Texaco (GE)
SUV--Czech Republic	1996	350	Cogen	Lignite Coal	Lurgi ⁽⁵⁾
Schwarze Pumpe--Germany	1996	40	Power/Methanol	Lignite Coal	Noell
Shell Pernis Refinery--Netherlands	1997	120	Cogen/Hydrogen	Oil	Shell
Elcogas--Spain	1998	300	Electric Power Generation	Sub-bituminous Coal/ Petcoke	PRENFLO
Sierra Pacific ⁽⁶⁾ --US (NV)	1998	100	Electric Power Generation	Sub-bituminous Coal	KBR ⁽⁷⁾
ISAB Energy--Italy	1999	500	Power/Hydrogen	Oil	Texaco (GE)
API--Italy	2000	250	Power/Hydrogen	Oil	Texaco (GE)
Delaware City Refinery--US (DE)	2000	180	Repower	Petcoke	Texaco (GE)
Sarlux/Sara Refinery--Italy	2000	550	Cogen/Hydrogen	Oil	Texaco (GE)
ExxonMobil--Singapore	2000	180	Cogen/Hydrogen	Oil	Texaco (GE)
NPRC Negishi Refinery--Japan	2003	342	Electric Power Generation	Oil	Texaco (GE)
Clean Coal Power Nakoso--Japan	2007	250	Electric Power Generation	Chinese Sub-bituminous Coal	MHI

Notes:

1. First year of operation on syngas.
2. Identifies the design fuel for the project though other fuels may have been tested and demonstrated.
3. Retired.
4. The El Dorado Refinery is now owned by Frontier Refining.
5. Fixed bed.
6. Not successful.
7. Air blown fluid bed.

Of the six operating coal-based IGCC plants, one is a 350 MW lignite cogeneration plant that has 26 Lurgi fixed bed gasifiers, and five are, entrained flow gasification demonstration projects, ranging in capacity from 250 to 300 MW, which are located in Florida, Indiana, Japan, The Netherlands, and Spain. The Wabash Indiana IGCC plant did not operate for an extended period in 2004 and 2005 because of contractual problems, but it is currently operating. Design data for these five demonstration plants are indicated in Table 3-4.

Table 3-4. Coal-Based IGCC Demonstration Plants

Project	Nuon Power⁽¹⁾	Wabash^(1, 2)	TECO Polk County^(1, 3)	Elcogas⁽¹⁾	Nakoso
Location	Buggenum, Netherlands	Indiana	Florida	Puertollano, Spain	Iwaki City, Japan
Technology	Shell	E-Gas (COP)	Texaco (GE)	PRENFLO (Krupp)	MHI
Startup Year	1994	1995	1996	1998	2007
Net Output, design, MW	252	262	250	300	250
LHV Efficiency, net design, %	43.1	39.2	41.2	42.2	42.5
Height, ft	246	180	295	262	Unknown
Fuel, design ⁽⁴⁾	Australian Bituminous Coal	Bituminous Coal	Bituminous Coal	Sub-bituminous Coal/Petcoke, 50/50	Chinese Sub-bituminous Coal
Fuel Consumption, tpd	2,000	2,200	2,200	2,600	1,900
Fuel Feed	Dry N ₂ lock hopper	Wet slurry	Wet slurry	Dry N ₂ lock hopper	Dry N ₂ lock hopper
Syngas HHV, Btu/scf	300	276	266	281	132
CTG Model	Siemens V94.2	GE 7FA	GE 7FA	Siemens V94.3	MHI 701DA
Firing temperature, °F	2,012	2,300	2,300	2,300	2,200
Combustors	Twin vertical silos	Multiple cans	Multiple cans	Twin horizontal silos	Multiple Cans
CTG Output, design, MW	155	192	192	200	124.2
STG Output, design, MW	128	105	121	135	125.8
Auxiliary Power, design, MW	31	35.4	63	35	--
Net Output, design, MW	252	262	250	300	250 ⁽⁵⁾
Net Output, achieved, MW	252	252	250	300	250 ⁽⁵⁾
NPHR, design, Btu/kWh HHV	8,240	9,030	8,600	8,230	8,027
NPHR, achieved, Btu/kWh (HHV) ⁽⁶⁾	8,240	8,600	9,100	8,230	8,350

Table 3-4 (Continued). Coal-Based IGCC Demonstration Plants

Project	Nuon Power	Wabash	TECO Polk County	Elcogas	Nakoso
Location	Buggenum, Netherlands	Indiana	Florida	Puertollano, Spain	Iwaki City, Japan
Technology	Shell	E-Gas (COP)	Texaco (GE)	PRENFLO (Krupp)	MHI
NPHR Note	--	Adjusted for HRSG feedwater heaters	Adjusted for gas/gas heat exchanger	--	--
ASU Pressure, psi	145	72.5	145	145	--
Nitrogen Usage	Syngas saturator	Vented	CTG NO _x control	Syngas saturator	Coal pressurization, NO _x control
NO _x Control	Saturation and N ₂ dilution	Saturation + steam injection	N ₂ dilution to combustors	Saturation and N ₂ dilution	Saturation
NO _x , 6% O ₂ , mg/Nm ³	25	100-125	100-125	150	20
Slag Removal	Lock-hopper	Continuous	Lock-hopper	Lock-hopper	Lock-hopper
Recycle Gas Quench	50% of gas, to 1,650° F	Some in second stage	None	67% of gas, to 1,475° F	None
Integration					
Water/steam	Yes	Yes	Yes	Yes	Yes
N ₂ Side ASU/CTG	Yes	No	Yes	Yes	No
Air Side ASU/CTG	Yes	No	No	Yes	Yes
Add Air Compressor	Yes	Yes	Yes	No	Yes
Gas Cleanup					
Particulate Removal	Cyclone/ceramic candle filter	Sintered metal candle filter	Water wash	Ceramic candle filter	Ceramic candle filter
Chloride Removal	Water scrubbing	Water scrubbing	Water scrubbing	Water scrubbing	Unknown

Table 3-4 (Continued). Coal-Based IGCC Demonstration Plants

Project	Project	Project	Project	Project	Project
Location	Location	Location	Location	Location	Location
Technology	Technology	Technology	Technology	Technology	Technology
COS Hydrolysis	Yes	Yes	Retrofit in 1999	Yes	Unknown
AGR Process	Sulfinol	MDEA	MDEA	MDEA	MDEA
Sulfur Recovery	Claus + SCOT TGR	Claus + Tail Gas Recycle	H ₂ SO ₄ Plant	Claus + Tail Gas Recycle	Gypsum
SO ₂ , 6% O ₂ , mg/Nm ³	35	40	40	25	8

Notes:

- Information taken from “Operating experience and improvement opportunities for coal-based IGCC plants,” Holt, Neville from *Science Reviews – Materials at High Temperatures*, Spring 2003.
- Wabash NPO and NPHR reported as 261 MW and 8,600 Btu/kWh in “The Wabash River Coal Gasification Repowering Project, an Update”, US DOE, September 2000.
- TECO NPO and NPHR reported as 250 MW and 9,650 Btu/kWh in “Tampa Electric Integrated Gasification Combined Cycle Project”, US DOE, June 2004.
- Identifies the design fuel for the project though other fuels may have been tested and demonstrated.
- Gross plant output.
- Achieved NPHR are instantaneous values from performance testing. Long term annual average heat rates vary with degradation and dispatch profile.

Each of the five projects was a government-subsidized IGCC demonstration, two in the United States, two in Europe, and one in Japan. Each of these IGCC plants consists of a single train (one ASU, one gasifier, one gas treating train, and one CC consisting of one CTG, one HRSG, and one STG). The Wabash IGCC unit has one spare gasifier in place; however, the spare gasifier is not connected to the process. Each plant experienced numerous problems during its first years of operation. Table 3-4 also summarizes the integration in each plant. Basically, there are three major areas for potential integration:

- Water and steam between the power generation area and the gasification island. High- and low-level heat rejection from the gasification process is utilized to produce CC power.
- The nitrogen side of the ASU and CTG. Waste nitrogen is mixed with the syngas to reduce NO_x formation and to increase power output.
- The air side of the ASU and the CTG. Air is extracted from the CTG compressor to reduce the auxiliary power and increase efficiency.

Figure 3-2 depicts potential areas of integration. The European plants have been highly integrated, partly in response to higher fuel prices, while the US plants have been less integrated. Both the Nuon Power Buggenum, Netherlands plant and the Elcogas Puertollano, Spain plant experienced operating difficulties as a result of the highly integrated design; most of these design and operating issues have been resolved.

Though the demonstration of these five commercial coal-fueled IGCC plants has provided benchmarks for expected capacity and environmental performance, uncertainty still remains regarding availability, reliability, and cost. The complexity and relative immaturity of the IGCC process increases opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. The high risks of capital cost overruns and low availability in the first few years of operation have presented obstacles to the development of non-subsidized coal-fueled IGCC projects. In addition, the long term operational efficiency of the demonstration plants is a better indicator of efficiency than the initial heat rate testing that has been reported.

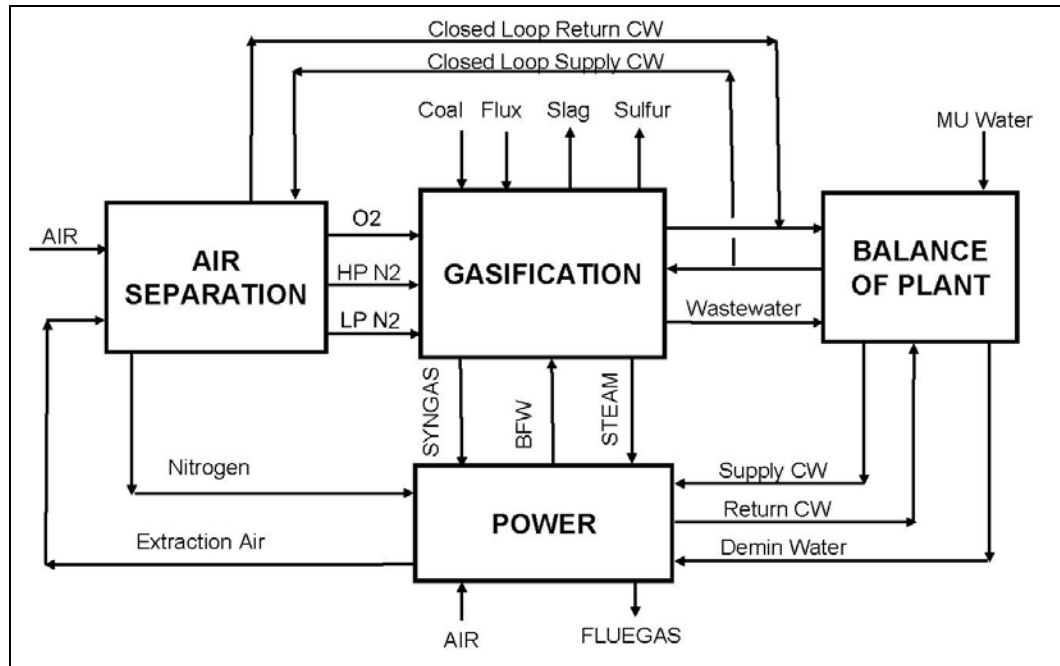


Figure 3-2. Potential Areas for Integration

3.6 Effect of Fuel Characteristics on Gasifier Selection

There are three general coal feedstocks typically considered for IGCC projects: Pittsburgh No. 8, Illinois No. 6, and PRB. Petcoke is a fourth solid fuel feedstock that is frequently considered for IGCC applications. Petcoke may be a lower cost fuel, but it is not as readily obtainable as coal. Historically, anthracite and lignite coals have not been seriously evaluated for IGCC projects, nor have waste coals such as gob (coal mine waste) and culm (waste produced when anthracite is mined and prepared for market, primarily rock and some coal).

Although the majority of sub-bituminous experience has been with the E-Gas (then Dow) gasification technology at the Louisiana Gasification Technologies Incorporated (LGTI) plant in Plaquemine Louisiana, the nature of the US coal market and the abundance of PRB have produced a strong interest in using PRB coals for IGCC using other gasification technologies. It has been determined that PRB will be the coal fuel for the Holcomb project.

Typical design values for the primary coals are listed in Table 3-5.

Characteristics	Coal Type		
	Pittsburgh No. 8	Illinois No. 6	PRB
Heat Content, Btu/lb (HHV)	12,300	10,200	8,400
Moisture, percent	8.0	14.1	29.4
Ash, percent	12.0	15.7	6.0
Sulfur, percent	4.0	4.3	0.34

The high moisture content in PRB coal is reduced to 2 to 5 percent (by weight) during milling/drying in the dry feed gasification processes to minimize impact on gasifier performance. The mill is swept with hot nitrogen or flue gas from combusted syngas. The dried, pulverized coal is separated from the wet gas and conveyed with dry nitrogen to an elevated silo; then it is sent to a lockhopper, where it is pressurized above the gasifier operating pressure and sent to a feed bin; and, finally, it is sent to the gasifier. After drying, the coal is kept under a nitrogen atmosphere to prevent fires.

In the COP and GE gasification processes, the inherent moisture in the coal reduces the amount of water needed to slurry the coal. However, the total moisture of the coal pumped to the gasifier is typically about 35 percent. Vaporizing all of this water requires the combustion of more than 10 percent of the carbon in the coal to CO₂, which reduces gasifier efficiency. In the COP gasification process, a portion of the coal slurry is injected into the hot raw gas from the first stage, where the coal is partially oxidized. This second-stage quench partially gasifies the injected coal. The unreacted, dry coal is filtered out of the gas and recycled to the first stage. This dry recycle step improves gasifier efficiency for PRB coal relative to the GE gasification process, but the COP gasification process is much less efficient and more expensive than the Shell gasification process for PRB coal.

In the GE gasification process, all of the inherent water in the coal and the liquid water in the slurry must be evaporated in the gasifier by combusting more CO to CO₂, which results in a lower cold gas efficiency than the COP and Shell gasification processes. Therefore, the GE gasification process has not been considered economical for PRB coal.

The dry-feed gasifiers can operate on any of the three general coal feedstocks. One design option is to size the syngas production components, the ASU, and the power generation equipment according to the maximum-case fuel properties. This will result in additional capital cost, but will allow the plant to achieve the same net plant output on syngas when operating on any of the fuels. A second option is to minimize the capital

expense; some examples of this include designing for a Pittsburgh No. 8 fuel and either derating if other fuels are used or co-firing natural gas with the syngas.

3.7 IGCC Performance and Emissions Considerations

IGCC net power output decreases with increasing ambient temperature, but this reduction is less than that of a natural gas combined cycle (NGCC) plant. The reduction in CTG air compressor capacity resulting from increased ambient temperature can be compensated for by increased nitrogen injection, which results in constant CTG power output, but increased auxiliary power consumption. Plant auxiliary power consumption also increases slightly with the ambient temperature for ASU air compression and cooling tower fans.

The CO and NO_x emissions estimates are based on CTGs firing syngas with nitrogen dilution and with SCR and CO oxidation catalyst in the HRSG. Some recent IGCC projects have assumed SCR and CO oxidation catalysts. The need for SCR and CO oxidation catalysts will be dependent on the permitting process and based on a BACT review. The CO and NO_x emissions estimates before SCR and CO catalyst are listed below:

- 25 ppmvd CO in the CTG exhaust gas.
- 15 ppmvd NO_x (at 15 percent by volume O₂) in the CTG exhaust gas.

The SO₂ emissions estimate was based on a 25 ppm molar concentration of sulfur as H₂S and COS in the syngas. Sulfur removal efficiencies of greater than 99 percent are achievable for an IGCC plant processing high sulfur coal or petcoke. During normal operation, a coal-fueled IGCC plant will have air emissions approaching those of an NGCC plant. Flaring during startups, shutdowns, and upsets can result in significant SO₂ emissions; however, the entrained flow gasification technologies under consideration can be started up and shut down without sour gas flaring under normal conditions. Sour gas flaring during upsets cannot be eliminated, but can be minimized by appropriate process design and operating procedures.

Syngas will flow through sulfur impregnated carbon, which is estimated to lower the syngas mercury concentration below 5 ppb by weight. Up to 40 percent of the mercury in the coal may be removed upstream of the sulfur impregnated carbon by scrubbing, which would reduce the mercury concentration to the inlet of the sulfur impregnated carbon to 30 to 42 ppb by weight. Eastman Chemical Company's coal gasification plant has used sulfur impregnated carbon beds for mercury removal since its startup in 1993. Eastman reports 90 to 95 percent mercury removal with a bed life of 18 to 24 months. Estimated emission limits are provided in Section 4.3.

3.8 Gasification Wastewater Treatment

There are two general categories of plant wastewater:

- Streams that contain metals from the as-received coal, referred to as gasification wastewater streams.
- Streams that do not contain these metals, referred to as balance-of-plant wastewater streams.

The gasification wastewater streams will be combined and treated separately from the balance-of-plant wastewater streams. Accurate specification of the process wastewater composition has been a problem on other operating gasification plants because of the wide variation in coal composition. The wastewater treatment design should accommodate variation in wastewater composition. There are three basic options for treating gasification wastewater streams:

- The open discharge concept, which consists of metals precipitation, followed by biological treatment to produce an effluent suitable for discharge.
- The zero liquid discharge (ZLD) concept, which consists of lime softening, followed by evaporation and/or crystallization to produce a solid salt for landfill disposal.
- Discharge to a municipal sewage treatment facility or other receiving stream. This option is generally considered impractical because the coal gasification wastewater exceeds typical pretreatment limitations.

Biological treatment of the gasification wastewater can be problematic because the diverse contaminants are believed to be sufficiently variable so that the operation would be unreliable, which could result in violations of expected permit requirements. The open discharge system would cost approximately the same as the ZLD option and is not a proven technology in this application. The operating costs are equivalent between the ZLD and open discharge systems. However, ZLD requires additional LP steam that could otherwise be used to generate an additional 2 to 5 MW of electricity.

3.9 Acid Gas Removal Technology

Sulfur in coal is converted to H₂S and COS during gasification. The molar ratio of H₂S to COS in the raw syngas from the gasifier varies according to the gasifier type, from approximately 13 to 1 for the Shell gasifier to approximately 26 to 1 for the COP and GE gasifiers. The resulting syngas is treated to meet CTG fuel and air emissions permit requirements. The requirement is for total sulfur in the clean syngas to be less than 25 ppm by weight, which is equivalent to 15 ppm by mole of COS and H₂S.

The three primary solvents considered for IGCC AGR are Rectisol, Selexol, and methyl diethanol amine (MDEA). Rectisol uses methanol as a solvent and is very efficient at removing sulfur compounds, ammonia, VOCs, mercury, HCN, and carbonyls. The technology can also be designed for efficient CO₂ removal. Compared to Selexol and MDEA the Rectisol technology is expensive.

Selexol solvent is a mixture of dimethyl ethers of polyethylene glycol, CH₃(CH₂CH₂O)_nCH₃, where n is between 3 and 9. UOP licenses Selexol technology for treating syngas from gasification. Selexol is a physical solvent. Its capacity to absorb sulfur compounds (including H₂S) and to absorb CO₂ increases with increasing pressure and decreasing temperature.

MDEA (HOC₂H₄)₂NCH₃ is a chemical solvent, specifically a selective amine used to remove H₂S, while leaving most of the CO₂ in the syngas. MDEA forms a chemical bond with H₂S and CO₂. MDEA's performance is nearly independent of operating pressure. Typical absorber operating temperatures with amines are between 80 and 120° F. Lower absorber operating temperatures increase both H₂S solubility and selectivity over CO₂.

Selection of an acid gas removal technology is an economic decision based on tradeoffs between capital costs, operating and maintenance costs, and required reduction in sulfur emissions.

3.10 Equivalent Availability

In the near term, an IGCC plant is not expected to be as reliable as a PC or CFB plant with respect to producing electricity from coal. Long-term equivalent availability for an IGCC plant is estimated to be in the range of 80 to 85 percent. Well-operated PC and CFB plants have established availabilities of 90 percent and greater. Based on past experience, IGCC availability during initial startup and the first several years of operation is expected to be significantly lower than the long-term targets. This can be mitigated by firing the CTGs with backup fuel (such as natural gas or low sulfur fuel oil). The equivalent availability of the combined cycle portion of an IGCC plant is expected to be above 90 percent. The equivalent availability of an IGCC plant could also be increased by providing a spare gasifier. Spare gasifier economics depend on the gasifier technology, cost of backup fuel, and plant dispatch economics. As seen in the past with other developing technologies, future generations of coal-fueled IGCC plants may take advantage of the lessons learned from existing operating plants, but significant startup problems should be expected.

3.10.1 First Generation IGCC Plants

Solids-related problems (erosion, pluggage, unstable flows, and syngas cooler tube leaks) caused significant gasification downtime for the four oldest coal-based IGCC demonstration plants. Gasifier burner and refractory maintenance also resulted in significant downtime for the COP and GE gasifiers. For the Buggenum and Puertollano plants, CTG problems related to syngas combustion and startup air extraction were significant. Since the problems were identified, plant modifications and O&M improvements have greatly improved performance; these plants now produce electricity at design rates and close to design efficiencies. There is not currently enough information on the Nakoso demonstration IGCC to determine where the early problems have arisen. However, it is clear that some of their operating targets have been pushed back. It is expected that these setbacks will be overcome with additional design considerations and gained operational experience.

Estimated annual equivalent availabilities for producing electricity from coal (syngas operation) are listed in Table 3-6 for the four oldest of the coal-based IGCC plants discussed in Section 3.5. These equivalent availabilities are for electricity production from coal or petcoke; power generation from firing the CTG on backup fuel is excluded. Gasification process availability for each of these plants was poor during the first several years of operation and continues to be a problem. The complexity and relative technological immaturity of large-scale commercial gasification processes increase opportunities for deficiencies in design, vendor-supplied equipment, construction, and O&M. During the first several years of plant operation, most of these deficiencies were corrected, and the plant staff has optimized the plant O&M as they have “moved up the gasification learning curve.” Design improvements are expected to be introduced on future IGCC plants, which should improve equivalent availability. There is not enough information on the Nakoso plant to form an opinion on the plant equivalent availability.

Table 3-6. Coal/Coke Fueled IGCC Plant Equivalent Availabilities

IGCC Plant Location	Nuon Buggenum, Netherlands	Global Energy Wabash, Indiana	TECO Polk County, Florida	Elcogas Puertollano, Spain
Gasifier	Shell	COP E-Gas	GE HTHR	PRENFLO
Net Output	252 MW	262 MW	250 MW	300 MW
Startup Year	1994	1995	1996	1998
Year after Startup	IGCC Equivalent Availability (percent)			
1	23	20	35	16
2	29	43	67	38
3	50	60	60	59
4	60	40	75	62
5	61	70	69	66
6	60	69	74	58
7	57	75	68	NA
8	67	78	81	
9	73	--	82	
10	78	--		
11	NA			

Note:

1. Data is based upon available information. Data reporting methodology varies somewhat between the plants.
2. Wabash Years 5-8 IGCC equivalent availability is estimated as 95 percent of reported syngas availability.
3. Wabash availability excludes periods when the plant was shut down because of no product demand (24 percent in Year 7 [2002] and 16 percent in Year 8 [2003], shutdown in Year 9 [2004], and Year 10 [2005]).

3.10.2 Second Generation IGCC Plants

The next, or second, generation of entrained flow gasification IGCC plants is expected to have improved availability compared to the first generation plants. Long-term equivalent availability for an IGCC plant is estimated to be in the range of 80 to 85 percent. Table 3-7 contains a projection of IGCC equivalent availabilities utilizing the Shell coal gasification process. These estimates are based on existing operating coal IGCC plants.

Table 3-7. Estimated Equivalent Availabilities for Shell IGCC			
	IGCC Equivalent Availability (percent)		
Year after Startup	Low		High
1	40	to	70
2	50	to	75
3	60	to	80
4	70	to	83
<i>5 and following</i>	<i>80</i>	<i>to</i>	<i>85</i>

Long term IGCC availability may be improved by installing a spare gasifier. Long-term IGCC unit forced outage rates are estimated to range from 10 to 15 percent without a spare gasifier and from 5 to 10 percent with a hot spare gasifier. The CTG(s) can operate on backup fuel when syngas is not available. The CC availability is expected to exceed 90 percent. It appears that the prevailing sentiment in the gasification community is that the economics of a spare gasifier will be difficult to justify in most power generation applications. For many utilities, there is reduced power demand in the spring and/or fall which would allow for annual planned outages. However, the Tri-State and Sunflower systems do not have significant demand reduction during these time periods. Therefore, there would be less opportunity to perform the required annual outages. Because there are three gasifier/CTG trains, these would not typically be full plant outages, but would reduce the available output from the plant by one third for an extended time. Full plant planned outages would be required approximately every six years for turbine maintenance. The annual planned outages are a contributing factor to the lower expected equivalent availability of an IGCC plant compared to a PC or CFB plant.

3.11 Other Commercial Entrained Bed Gasification Experience

GE water quench type gasifiers have been in commercial operation on coal or petcoke since 1983, producing syngas for chemical production. Two plants of note are the Eastman Chemical Plant in Kingsport, Tennessee, and the Ube Ammonia Plant in Japan. The syngas from these two plants is used to produce acetyl chemicals and ammonia, respectively. Kingsport has two gasifiers; one is normally operated and the other is a spare. Ube has four gasifiers; three are normally operated and one is a spare. Ube originally gasified crude oil, then switched to refinery residuals, then to coal, and has been gasifying a total of 1,650 tpd of petcoke since 1996. At Kingsport and Ube, an average syngas availability of 98 percent is achieved by rapid switchover to the spare

gasifier, which is on hot standby, and the high level of resources (e.g., O&M) applied to the gasification process.

The Eastman Kingsport plant has occasionally been referred to as an IGCC plant. This is incorrect because it produces no power; the Eastman plant produces syngas for chemical production, with no power generation. The economics of chemical production at the Eastman facility are different from the economics of the power market. As such, a fully redundant gasifier is warranted at the Eastman facility. Eastman has made gasification one of its focus areas, as evidenced by its formation of the Eastman Gasification Services Company.

3.12 Current Announced Electric Generation Industry Activity

Major industry participants, such as AEP and Duke, are considering implementing IGCC projects. In addition, numerous smaller companies are pursuing gasification projects using state and federal grants. One coal-fueled IGCC project is currently under construction in the US. The Duke Energy Edwardsport plant is over 50 percent completed. Duke expects the plant to begin commercial operations in late 2012 or early 2013. Although the Global Energy plant in Lima, Ohio, is technically under construction, the company stopped construction October 2006 and has not been able to generate enough financing to restart.

The four projects described below were selected because of their perceived stage of development and their applicability to IGCC projects. The data contained in the descriptions comes from publicly available sources. There is generally not enough data to describe the scope of work associated with the cost estimates provided, or to compare them with costs presented in this study.

3.12.1 Duke Energy

On October 26, 2004, PSI Energy, Cinergy's (now Duke) Indiana subsidiary, signed a letter of intent with GE and Bechtel Corporation to study the feasibility of an IGCC plant. This letter of intent was the first step toward reaching a contract to design and construct the plant. This plant was the first one announced under the GE/Bechtel alliance.

On September 21, 2005, Vectren Corp. and Cinergy/PSI announced that they would work together on plans for a clean coal power plant that would generate about 600 MW of electrical capacity. On March 10, 2006, Cinergy and Duke Energy merged under and retained the Duke Energy name. On March 22, 2006, an agreement was signed with GE and Bechtel to begin a FEED, which took about 12 months to complete.

Construction on the Edwardsport plant began in 2008 and has progressed steadily. The plant is scheduled to reach mechanical completion in 2012.

3.12.2 Excelsior Energy, Inc.

On June 10, 2004, COP and Excelsior Energy, Inc., signed a development and technology licensing agreement for an IGCC plant utilizing COP E-Gas technology. Excelsior's Mesaba Energy Project will be located in northeastern Minnesota in an area known as the Iron Range.

Excelsior has been engaged in the development of this project since 2001. The Mesaba Energy Project has received broad-based support from state government, labor, business, and political leaders within Minnesota and in Washington, DC. Supportive legislation passed in Minnesota provides the project with an exemption from the certificate of need process for initial and future generation and transmission.

On October 26, 2004, the US DOE announced that the Excelsior Energy team had been selected to receive a \$36 million award as part of the 2002 CCPI. At that time, the estimated total cost for the coal-based demonstration project was reported to be \$1.18 billion (the basis for this number is unclear). This project was one of two selected to demonstrate advanced power generation systems using IGCC technology. Excelsior Energy has also been awarded \$10 million in funding from a Minnesota renewable energy account.

On August 29, 2005, Excelsior Energy announced that it had selected a preferred and an alternate site. The preferred site is in Itasca County, Minnesota. Approval of site selection must be obtained from the Minnesota Public Utilities Commission. Excelsior Energy has secured an option for more than 1,000 acres. The project cost for a single 600 MW 2-on-1 IGCC facility was reported as \$1.5 billion.

On October 5, 2005, the US DOE announced its intent to prepare an Environmental Impact Statement (EIS). In an October 2005 presentation, the total project cost was identified as \$1.97 billion (the basis for this number is unclear, but likely includes O&M and fuel for the demonstration period), with the project expected to be operational in 2012 and producing up to 600 MW (net) of electricity. A 2012 operational date appears unlikely since construction has not yet started. The project is expected to be able to utilize bituminous and sub-bituminous coals as well as petcoke blends. The design heat rate, utilizing bituminous coal, would be 8,600 Btu/kWh.

The March 27, 2006, issue of GHG Transactions & Technologies reported that the project will capture between 20 and 30 percent of the CO₂ emissions when it begins operation. On May 22, 2006, funding was received from the US DOE.

Since 2006, Excelsior has been making minor headway in project development including an agreement with COP for a process design package, acquisition of rights to a site, execution of transmission agreements, and completion of the environmental impact study. The project was also selected by the US DOE for its federal loan guarantee program.

3.12.3 Sweeny IGCC/SNG Project

COP is developing the Sweeny IGCC and SNG project to produce power and energy for the Sweeny oil refining complex. Project development began in 2008 when COP completed conceptual engineering of the plant. The project will use the common technologies for IGCC and SNG production to produce a syngas stream that can be used for either power generation or for SNG production. The gasifier feed will be petcoke produced at the adjacent Sweeny refinery. The plant will replace or supplement a 440 MW gas fired cogeneration plant that currently supplies power and steam to the refinery. The IGCC plant is also expected to capture and sequester about 85 percent of its CO₂ emissions.

In 2009 the Sweeny gasification project was selected by the US DOE for a \$3 million cooperative agreement cost sharing for project development. COP is hopeful that the project will also be selected to receive \$1.4 billion of ARRA funds. The plant is expected to begin operations in 2014 or 2015.

3.12.4 The ERORA Group, LLC

In 2004, the ERORA Group began developing the Taylorville Energy Center, a 677 MW minemouth IGCC project in Illinois based on GE technology. The reported project cost at that time was \$1.1 billion (the basis for this number is unclear), with a projected construction start in 2007 and a commercial operation date in 2010. Permits for the mine have been acquired, and the air permit application has been filed. The Illinois Clean Coal Review Board (CCRB) and the Illinois Department of Economic Opportunity awarded ERORA a \$5.75 million grant for feasibility studies, as well as engineering and design studies.

On April 5, 2005, Eastman Chemical Company and ERORA entered into an agreement to study the feasibility of chemicals co-production at the proposed IGCC facility. Initially envisioned as a PC facility in 2003, ERORA received a grant from the Illinois CCRB to study the potential for coal gasification. The co-production of chemicals from syngas has the potential to significantly improve the economics of power generation. The project is expected to be based on a 2-on-1 7FB CC with three gasifiers (two, plus one full spare).

On January 23, 2006, ERORA signed a license agreement with GE Energy, authorizing the use of GE's gasification technology for the project. GE also has been selected to provide the process design for the gasification portion of the facility and the power island.

Between 2006 and 2010 the plant design changed from a pure IGCC design without CO₂ capture to a co-production design for producing SNG and power. The power plant is expected to be a state-of-the-art SNG fired combined cycle. The plant could be run in SNG mode or power mode depending on the prices of electricity and SNG. SNG production has CO₂ capture inherent in its design. The state of Illinois passed a clean coal bill early in 2009 that provided funds for a FEED study of the Taylorville Energy Center. In March 2010 ERORA estimated that the total cost of the plant would be about \$3.5 billion. The basis of this cost estimate is unknown.

ERORA is also developing a similar project in Henderson County, Kentucky, known as Cash Creek.

3.12.5 Mississippi Power

Mississippi Power, a wholly owned subsidiary of Southern Company, announced on May 27, 2010 the continued development of the Kemper County IGCC power plant, reversing their announcement on April 30, 2010 to cancel the project. The announcement to further pursue the project followed the Mississippi Public Service Commission's issuance of a new order which conditionally approves the construction of the plant. The new order raises the cost cap of the plant to \$2.88 billion and allows Mississippi Power to raise financing capital for the plant from its customers prior to the commercial operation of the plant beginning in 2012. The original order issued by the Public Service Commission did not allow Mississippi Power to raise financing capital for the plant from its customers prior to commercial operation. The original order also stipulated that the plant had to be constructed at a cost less than \$2.4 billion. This original order by the Mississippi Public Service Commission was in response to Mississippi Power's January 16, 2009 filing for a certificate of public convenience and necessity to construct the proposed IGCC plant.

The IGCC plant will utilize transport integrated gasification (TRIG) technology, has a planned net capacity of 582 MW, and an expected commercial operation date of 2014. The project will make use of regionally available lignite coal. Southern Company, along with the US DOE, has been engaged in the development and research of coal gasification technologies at the Power Systems Development Facility (PSDF) near Wilsonville, Alabama. The Kemper County IGCC facility is planned to be a scale-up of the plant already in operation at the PSDF facility. The scaled-up design was developed

collaboratively by Southern Company, Kellogg Brown Root (KBR), and the US DOE. The TRIG design is intended to be capable of gasifying low rank coals such as PRB and lignite.

3.12.6 Summary of Proposed Projects

The development activities of the four projects discussed in the previous subsections represent advances in the development of new IGCC plants within the US. Entrained flow gasification technology has been selected for four of the five projects.

The Duke and ERORA projects are based on bituminous coal. Excelsior Energy anticipates a blend of fuels that would include PRB coal, Illinois coal, and/or petcoke. The Sweeny project is based on petcoke. The Mississippi Power project plans to gasify lignite.

Since 2006 there has been an increased interest in producing SNG via gasification and then using the SNG to produce power. This has been evident in the focus of some IGCC plants to co-produce SNG and power. Other projects have focused only on SNG production and only produce power as a bottoming cycle to the SNG process. Black & Veatch expects that the continued interest in SNG production will be tied to natural gas prices.

4.0 Technology Screening Performance and Cost Estimates

Black & Veatch developed performance and cost estimates of four baseload generation technology options. The performance and cost data were utilized in a busbar screening tool discussed in Section 5.0. For purposes of this evaluation, it was critical that the technologies be evaluated on a consistent basis relative to each other. The following four baseload technologies were considered:

- Supercritical PC.
- Subcritical PC.
- CFB.
- IGCC.

The needs of the project require a net plant output of 895 MW. Therefore, the units were designed to produce at least 895 MW (net) at the plant boundary at any ambient temperature less than the hot day. The PC and CFB units were sized at 895 MW net. The IGCC unit was configured to best satisfy this requirement without substantially exceeding a net plant output of 895 MW. Duct firing capabilities were not included with the IGCC unit.

The cost estimates have assumed that this project would be an add-on unit at the existing Holcomb Station.

4.1 Assumptions

Black & Veatch developed a list of assumptions for each technology. These assumptions are provided in the following subsections.

4.1.1 Overall Assumptions

The plant location would be in western Kansas. For the basis of the estimates, an elevation of 2,915 feet (the elevation of Holcomb, Kansas) was selected. Project conditions include the following:

- Ambient pressure--13.21 psia.
- Hot day--94° F dry bulb, 73° F wet bulb.
- Average day--52° F dry bulb, 43° F wet bulb.
- Powder River Basin (PRB) coal from the Dry Fork mine is assumed as the fuel source. Dry Fork mine ultimate and proximate analysis is provided in Table 4-1.

Table 4-1. Dry Fork Mine PRB Coal Properties			
	Target	Range	
HHV as received, Btu/lbm	8,045	7,800	8,300
Fuel Proximate Analysis, as received			
Total Moisture, weight percent	32.06	30.50	33.80
Volatile Matter, weight percent	30.12	28.05	32.01
Fixed Carbon, weight percent	33.05	31.64	34.14
Ash, weight percent	4.77	4.20	6.50
Fuel Ultimate Analysis			
Total Moisture, weight percent	32.06	30.50	33.80
Ash, weight percent	4.77	4.20	6.50
Carbon, weight percent	47.22	46.55	48.14
Hydrogen, weight percent	3.23	2.98	3.37
Nitrogen, weight percent	0.72	0.65	0.69
Sulfur, weight percent	0.33	0.25	0.47
Oxygen, weight percent	11.67	10.68	13.68
Trace Elements			
Mercury, weight percent	8×10^{-6}	2×10^{-6}	10×10^{-6}
SO ₂ lbm/MBtu (HHV) ⁽¹⁾	0.82	--	--
Note:			
1. Assumes 100 percent conversion of available sulfur in fuel to SO ₂			

4.1.2 Thermal Unit Cycle Arrangement Assumptions

Cycle arrangement assumptions specific to each PC and CFB case used in the development of the estimates are summarized in Table 4-2. Cycle arrangement assumptions were developed based on Black & Veatch experience.

AQCS were selected as a design basis to develop performance and cost estimates and were selected to meet anticipated air quality requirements. Actual AQCS would be selected to control criteria pollutants under a Prevention of Significant Deterioration (PSD) permit and would be subject to a Best Available Control Technology Review (BACT). AQCS are based on input from Tri-State/Sunflower and their recent permitting activities with the Holcomb new unit addition. The assumed AQCS for the PC and CFB technologies are provided as follows:

- PC
 - NO_x Control
 - Combustion controls -- Low NO_x burners (LNB) and over-fire air (OFA) (air staging).
 - Post combustion controls -- Selective catalytic reduction (SCR)
 - SO₂ Control -- Semi-dry lime spray dryer absorber (SDA) flue gas desulfurization (FGD).
 - CO Control -- Combustion design and boiler tuning.
 - PM₁₀ Control -- Pulse jet fabric filter (PJFF).
 - Hg Control -- Brominated activated carbon injection (ACI).
- CFB
 - NO_x Control
 - Combustion controls -- Combustion design (low combustion temperatures), OFA.
 - Post combustion controls -- Selective non-catalytic reduction (SNCR).
 - SO₂ Control – In-bed sorbent injection and polishing semi-dry lime spray dryer absorber (SDA) FGD.
 - CO Control -- Combustion design and boiler tuning.
 - PM₁₀ Control -- PJFF.
 - Hg Control -- Brominated ACI.

Table 4-2. PC and CFB Cycle Arrangement Assumptions			
Design Net Plant Output at Hot Day, MW	895	895	895
Steam Generator	Supercritical PC	Subcritical PC	CFB
Number of Steam Generators	1	1	3
Number of Steam Turbine Generator	1	1	1
Reheat Cycle	Yes	Yes	Yes
Average Day Throttle Pressure, psi	3,500	2,400	2,400
Main Steam Temperature, ° F	1,080	1,050	1,050
Reheat Steam Temperature, ° F	1,080	1,050	1,050
Steam Turbine Arrangement	TC4F-40.0	TC4F-40.0	TC4F-40.0
Rankine Cycle Heat Rejection	Wet MDCT	Wet MDCT	Wet MDCT
Boiler Feed Pump Drive	Steam Turbine	Steam Turbine	Steam Turbine
Total Feedwater Heaters	8	8	8
Fuel	PRB	PRB	PRB
Fuel Source	Dry Fork Mine	Dry Fork Mine	Dry Fork Mine
Start-up fuel	Natural Gas	Natural Gas	Natural Gas
NO _x , Post Combustion Control	SCR	SCR	SNCR
SO ₂ Control, Post Combustion	SDA FGD	SDA FGD	Polishing SDA FGD
PM ₁₀ Control	PJFF	PJFF	PJFF
Hg Control	ACI	ACI	ACI
Note: MDCT-- mechanical draft cooling tower.			

4.1.3 IGCC Cycle Arrangement Assumptions

Unlike conventional PC and CFB units, an IGCC unit cannot be sized to match a selected net plant output. The constraints are similar to that of a conventional natural gas fired simple or combined cycle units. The CTGs come in discrete sizes and are much more sensitive to changes in elevation and ambient temperature than thermal plants.

Currently, the available IGCC design configurations are based on state-of-the-art conventional “F” class CTGs modified to fire syngas. The GE 7F-SG and the SPG SGT6-5000F CTGs are the most likely models to be incorporated into an IGCC. At ISO conditions (sea level, 59° F, 60 percent relative humidity), these CTGs are rated at 232 MW when firing syngas. A single 7F-SG or SGT6-5000F in an IGCC configuration produces a nominal 300 MW (net) at ISO conditions. Hence, a 3-on-1 IGCC configuration will produce a nominal 900 MW (net) at ISO conditions. The net output will vary somewhat depending on the gasification technology employed, as well as with the degree of integration.

The IGCC unit was configured to best satisfy the 895 MW (net) project capacity without substantially exceeding a net plant output of 895 MW. IGCC units utilize CTGs and large air compressors in the ASU. Because CTGs and air compressors are mass flow devices, their performance is affected with changes in ambient conditions. Generally speaking, as temperatures rise, and ambient pressure drops, CTG efficiency and output decreases while air compressor loads increase, due to the lower density of the air. A decrease in CTG gross output and an increase in ASU auxiliary load have a negative effect on plant performance. The coal gasification process itself is minimally affected by changes in ambient conditions. Adjusting for site-specific elevation and temperature, the resultant net plant capacity at the average annual temperature is 800,900 kW. On a peak summer day, this output is further degraded to 747,300 kW. The net output on a hot day can be partially restored using evaporative inlet cooling on the CTGs.

Cycle arrangement assumptions used in the development of the estimates are summarized in Table 4-3. Cycle arrangement assumptions were developed based on Black & Veatch experience.

AQCS were selected as a design basis to develop performance and cost estimates and were selected to meet anticipated air quality requirements. Actual AQCS would be selected to control criteria pollutants under a PSD permit and would be subject to a BACT. The assumed AQCS for the IGCC technology is provided as follows:

- NO_x Control
 - SCR catalyst.
 - Nitrogen dilution.
 - Syngas saturation.
- SO₂ Control
 - COS hydrolysis.
 - Selexol acid gas removal.
 - Claus SRU with tailgas recycle.
- PM₁₀ Control
 - Candle filter.
- Hg Control -- sulfided carbon bed.

Table 4-3. IGCC Cycle Arrangement Assumptions	
Gasifier Technology	Shell
Number of Gasifiers, count	3
CTG Technology	GE 7F-SG
Number of CTGs, count	3
Number of HRSGs, count	3
Duct Firing	No
Steam Turbine	Subcritical TC2F-33.5
Throttle Conditions, psia / °F / °F	1,565 / 1,000 / 1,000
Cycle Heat Rejection	Wet MDCT
NO _x Control	SCR, nitrogen diluent, and syngas saturation
SO ₂ Control	Pre-combustion acid gas removal
CO Control	None ⁽²⁾
Particulate Control	Candle Filter
Hg Control	Sulfided carbon bed
Boiler Feed Pump Drive	Motor
Note: Space would be allocated for CO oxidation catalysts in the future.	

4.2 Performance Cases

Multiple performance cases were run for each of the four technologies.

4.2.1 PC and CFB Cases

Three performance cases were run for each thermal cycle at full-load conditions. These cases, presented in Table 4-4, Table 4-5, and Table 4-6, are as follows:

- Hot day case (capacity design case)--VWO.
- Rated average ambient case--95 percent VWO.
- Average ambient case--VWO.

4.2.2 IGCC Cases

Two cases were run for the IGCC burning syngas and one case was run for the IGCC burning a mix of syngas and natural gas. These cases, presented in Table 4-7, are as follows:

- Syngas hot day case--Evaporative cooling, no duct firing.
- Syngas average ambient case--No evaporative cooling, no duct firing.
- Mix of syngas and natural gas average ambient case--No evaporative cooling, no duct firing. This case assumes that one gasifier is unavailable and that one of the CTGs is operating on natural gas. The performance is a composite of the two CTGs burning syngas and one CTG burning natural gas.

Table 4-4. Supercritical PC Performance Estimates			
Case	Hot Day	Avg Day	Avg Day
Steam Turbine Load, percent	100	95	100
Throttle Pressure, psig	3,675	3,500	3,675
Backpressure, in. HgA	2.60	1.57	1.64
Heat to Steam, MBtu/h	6,930	6,632	6,930
Boiler Efficiency (HHV), percent	85.19	85.19	85.19
Fuel Input, MBtu/h	8,135	7,784	8,134
Net Turbine Output, kW	952,100	919,400	961,500
Total Auxiliary Load, kW	57,100	55,200	57,700
Net Plant Output, kW	895,000	864,200	903,900
Net Turbine Heat Rate (HHV), Btu/kWh	7,279	7,213	7,207
Net Plant Heat Rate (HHV), Btu/kWh	9,089	9,007	9,000
Net Plant Efficiency (HHV), percent	37.54	37.88	37.91

Table 4-5. Subcritical PC Performance Estimates			
Case	Hot Day	Avg Day	Avg Day
Steam Turbine Load, percent	100	95	100
Throttle Pressure, psig	2,520	2,400	2,520
Backpressure, in. HgA	2.60	1.57	1.65
Heat to Steam, MBtu/h	7,110	6,803	7,110
Boiler Efficiency (HHV), percent	85.19	85.19	85.19
Fuel Input, MBtu/h	8,346	7,986	8,346
Net Turbine Output, kW	952,100	916,700	959,500
Total Auxiliary Load, kW	57,100	55,000	57,600
Net Plant Output, kW	895,000	861,700	901,900
Net Turbine Heat Rate (HHV), Btu/kWh	7,468	7,422	7,410
Net Plant Heat Rate (HHV), Btu/kWh	9,325	9,268	9,253
Net Plant Efficiency (HHV), percent	36.59	36.82	36.87

Table 4-6. CFB Performance Estimates			
Case	Hot Day	Avg Day	Avg Day
Steam Turbine Load, percent	100	95	100
Throttle Pressure, psig	2,520	2,400	2,520
Backpressure, in. HgA	2.60	1.58	1.65
Heat to Steam, MBtu/h	7,187	6,876	7,187
Boiler Efficiency (HHV), percent	85.04	85.04	85.04
Fuel Input, MBtu/h	8,451	8,086	8,451
Net Turbine Output, kW	962,400	925,400	969,800
Total Auxiliary Load, kW	67,400	64,800	67,900
Net Plant Output, kW	895,000	860,600	901,900
Net Turbine Heat Rate (HHV), Btu/kWh	7,468	7,431	7,410
Net Plant Heat Rate (HHV), Btu/kWh	9,442	9,396	9,370
Net Plant Efficiency (HHV), percent	36.14	36.32	36.42

Table 4-7. 3-on-1 GE 7F-SG IGCC Performance Estimates

Case	Hot Day	Average	Average
Fuel	Syngas	Syngas	Syngas/ Natural Gas
Evaporative Cooler	On	Off	Off
Throttle Pressure, psig	1,445	1,485	800
Inlet Temperature, °F	73	52	52
Backpressure, in. HgA	2.3	1.7	0.9
CTG Output (each), kW	199,000	216,000	216,000/165,600
CTG Heat Rate, Btu/kWh (LHV)	8,442	8,287	8,287/9,259
CTG Fuel Input, MBtu/h (LHV)	1,680	1,790	1,790/1,533
Fuel Input, MBtu/h (LHV)	5,040	5,370	5,113
Coal Input, MBtu/h (HHV)	6,736	7,177	4,785
Gross Plant Output, kW	932,700	1,001,500	897,000
Total Auxiliary Load, kW	185,400	200,600	139,900
Net Plant Output, kW	747,300	800,900	757,100
Net Plant Heat Rate (HHV), Btu/kWh	9,014	8,962	8,517
Net Plant Efficiency (HHV), percent	37.9	38.1	40.1

4.3 Emissions

For purposes of this screening evaluation, expected emission rate performance is listed in Table 4-8 have been utilized. Final permit levels may vary on a case-by-case basis.

Table 4-8. Expected Emission Rate Performance			
	PC	CFB	IGCC
NO _x , lb/MBtu	0.05	0.07 – 0.09	0.01 – 0.02
SO ₂ , lb/MBtu	0.06	0.07 – 0.08	0.03 – 0.10
PM, lb/MBtu	0.012	0.010 – 0.015	0.007 – 0.011
Hg, lb/GWh	0.020	Note 5	Note 5
Notes:			
1. PC values are consistent with recent Holcomb Station Unit 2 proposed Air Emission Source Construction Permit. 2. CFB and IGCC indicative emissions limit ranges are representative of recent Best Available Control Technology and Maximum Achievable Control Technology. 3. MBtu on an HHV basis. 4. PM values are filterable. 5. As of June 2009, Mercury (Hg) limits have been removed from the EPA New Source Performance Standards (NSPS). This leaves the fate of Hg as a hazardous air pollutant (HAP) which is subject to a Maximum Available Control Technology review (MACT) at major sources of HAPs. Hg emissions limits are determined on a case by case basis during the permitting process. The proposed Supercritical PC for Holcomb Unit 2 is not a major source of HAPs.			

4.4 Capital Costs

The cost estimates in this report include estimated costs for equipment and materials, construction labor, engineering services, construction management, indirects and other costs. The estimates were based on Black & Veatch proprietary estimating templates and experience. These estimates are overnight screening-level estimates prepared for the purpose of project screening, resource planning, comparison of alternative technologies, etc. The capital costs are based on an engineering, procurement, and contracting (EPC) methodology which is exclusive of Owner’s cost. EPC cost estimates are presented in Table 4-9.

The information is consistent with recent experience and market conditions, but as demonstrated over the last few years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes.

The sum of the capital cost and the Owner’s cost equals the total project cost or the total capital requirement for the project. Typically, the scope of work for EPC costs is the

base plant, which is defined as being within the fence boundary with distinct terminal points. Typical Owner’s costs that may apply are listed in Table 4-10. For this screening analysis, the Owner’s costs have been estimated as 35 percent of the EPC capital cost. An allowance for interconnections, such as transmission, water, natural gas, and rail, has not been included. Interconnection costs can be major cost contributors to a project and should be evaluated in greater detail in later stages of project development.

For the IGCC project, the Owner’s risk contingency has been estimated as 6 percent of the EPC cost. This contingency includes unforeseeable repairs and modifications needed during the initial years of operation. To attain high availability, it was assumed that the Owner would have to aggressively correct deficiencies and implement enhancements as they are identified. Some of the costs for correcting deficiencies may be recovered from the EPC contractor, but the Owner should expect to have significant initial operating costs that will not be reimbursed by the EPC contractor. Depending on the contracting arrangement and guarantees obtained, some of this responsibility/liability might be accepted by the EPC contractor, but it was assumed that the EPC contractor would pass on these costs to the Owner.

Table 4-9. Overnight Capital Cost Estimates (2010\$)

	Supercritical PC	Subcritical PC	CFB	IGCC
Average Day Net Plant Output, MW	903,900	901,900	901,900	800,900
EPC Cost, \$Million	1,941	1,888	2,128	2,760
EPC Cost, \$/kW	2,147	2,093	2,359	3,446
Owner’s Cost, percent	35	35	35	35
Owner’s Risk Contingency, percent	0	0	0	6
Total Owner’s Cost, \$Million	679	661	745	1,132
Total Project Cost, \$Million	2,620	2,548	2,873	3,892
Total Project Cost, \$/kW	2,899	2,825	3,185	4,859

Note: Unit costs based on average day net plant output.

Table 4-10. Potential Owner's Costs

<p>Project Development:</p> <ul style="list-style-type: none"> • Site selection study • Land purchase/options/rezoning • Transmission/gas pipeline rights of way • Road modifications/upgrades • Demolition (if applicable) • Environmental permitting/offsets • Public relations/community development • Legal assistance <p>Utility Interconnections:</p> <ul style="list-style-type: none"> • Natural gas service (if applicable) • Gas system upgrades (if applicable) • Electrical transmission • Supply water • Wastewater/sewer (if applicable) <p>Spare Parts and Plant Equipment:</p> <ul style="list-style-type: none"> • Air quality control systems materials, supplies, and parts • Acid gas treating materials, supplies and parts • Combustion and steam turbine materials, supplies, and parts • HRSG, gasifier and/or boiler materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies <p>Owner's Project Management:</p> <ul style="list-style-type: none"> • Preparation of bid documents and selection of contractor/s and suppliers • Provision of project management • Performance of engineering due diligence • Provision of personnel for site construction management 	<p>Plant Startup/Construction Support:</p> <ul style="list-style-type: none"> • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals/reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchase • Construction all-risk insurance • Acceptance testing • Supply of trained operators to support equipment testing and commissioning <p>Taxes/Advisory Fees/Legal:</p> <ul style="list-style-type: none"> • Taxes • Market and environmental consultants • Owner's legal expenses: <ul style="list-style-type: none"> • Power Purchase Agreement • Interconnect agreements • Contracts--procurement and construction • Property transfer <p>Owner's Contingency:</p> <ul style="list-style-type: none"> • Owner's uncertainty and costs pending final negotiation: <ul style="list-style-type: none"> • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreement (e.g., interconnection contract costs) <p>Financing:</p> <ul style="list-style-type: none"> • Financial advisor, lender's legal, market analyst, and engineer • Development of financing sufficient to meet project obligations or obtain alternate sources of lending • Interest during construction • Loan administration and commitment fees • Debt service reserve fund
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4.5 Nonfuel O&M Costs

The O&M estimates have been derived from other detailed estimates developed by Black & Veatch and are based on vendor estimates and recommendations, actual performance information gathered from units in service, and representative costs for staffing, materials, and supplies. Plant staffing was assumed to provide operating and routine maintenance.

Table 4-11 lists the assumed costs of major consumables. The assumed O&M consumables costs were selected to be representative of a western Kansas plant site location. Summary estimates of fixed and variable nonfuel O&M costs are provided in Table 4-12.

Table 4-11. O&M Consumables Cost Assumptions (2010\$)	
Limestone, \$/ton	25
Lime, \$/ton	130
Aqueous Ammonia Cost, \$/ton ⁽¹⁾	290
Powder Activated Carbon, \$/lbm ⁽²⁾	1.00
SCR Catalyst, \$/m ³	6,000
Raw Water Cost, \$/1,000gal	0.50
Notes:	
1. Ammonia is aqueous with a concentration of 19 percent ammonia.	
2. Brominated powder activated carbon.	

Table 4-12. Estimated O&M Costs at Average Ambient Conditions (2010\$)				
	Supercritical PC	Subcritical PC	CFB	IGCC
Staff Count	90	90	94	145
Average Day Net Plant Output, kW	903,900	901,900	901,900	800,900
Fixed Costs, \$1,000	14,270	14,130	15,260	25,650
Fixed Costs, \$/kW	15.79	15.67	16.92	32.03
Variable Costs, \$1,000	29,720	28,940	35,480	34,590
Capacity Factor, percent	90	90	90	85
Annual Generation, GWh	7,126	7,111	7,111	5,964
Nonfuel Variable Costs, \$/MWh	4.17	4.07	4.99	5.80
Note: Unit costs based on average day net plant output.				

5.0 Economic Analysis

A busbar analysis was developed to compare the four technologies. The economic criteria, summary of inputs, and results are presented in this section.

5.1 Economic Criteria

The economic criteria utilized for the busbar analysis are summarized in Table 5-1. The spreadsheets were created to allow changes in assumptions to automatically update the analysis. A forecast for the delivered price of a typical PRB coal to the western Kansas site is shown in Table 5-2.

Table 5-1. Economic Criteria	
Owner's Cost Adder, Percent of EPC Cost, percent	35
Owner's IGCC Risk Contingency, Percent of EPC Cost, percent	6.0
PC and CFB Capacity Factor, percent	90
IGCC Capacity Factor, percent	85
General Inflation, percent	3.0
Present Worth Discount Rate, percent	8.5
Levelized Fixed Charge Rate, percent	10.5
Evaluation Years	30

5.2 Busbar Analysis

The economic criteria from Table 5-1 and the fuel forecasts from Table 5-2, along with the key performance and cost data listed in Table 5-3, were utilized in a 30 year levelized busbar analysis.

Performance was based on the annual average day. The projected capacity factors for the PC and CFB units are 90 percent. The projected long term capacity factor for the IGCC unit is 85 percent. . In order to achieve an 85 percent capacity factor in the first three years, natural gas would be required as a back-up fuel. The IGCC analysis assumes a syngas-fueled equivalent availability of 50 percent in the first year of operation, 60 percent in the second year, and 75 percent in the third year. The remaining hours of generation are assumed to be provided by burning natural gas. A first year natural gas cost of 6.00 \$/MBtu was assumed.

The results are presented in Table 5-4. The results are also presented graphically in Figure 5-1.

Table 5-2. Fuel Forecast, PRB Coal				
Year	Coal Cost, \$/MBtu ⁽¹⁾	Coal Delivery Cost, \$/ton ⁽²⁾	Coal Delivery Cost, \$/MBtu	Delivered Coal Cost, \$/MBtu
2011	0.64	10.94	0.68	1.31
2012	0.68	9.77	0.61	1.29
2013	0.70	10.06	0.63	1.32
2014	0.72	10.29	0.64	1.36
2015	0.74	10.55	0.66	1.39
2016	0.76	10.83	0.67	1.43
2017	0.78	11.11	0.69	1.47
2018	0.81	11.39	0.71	1.51
2019	0.83	11.65	0.72	1.55
2020	0.86	11.91	0.74	1.60
2021	0.88	10.49	0.65	1.53
2022	0.91	10.72	0.67	1.57
2023	0.94	10.92	0.68	1.61
2024	0.96	11.16	0.69	1.66
2025	0.99	11.37	0.71	1.70
2026	1.02	11.62	0.72	1.74
2027	1.05	11.88	0.74	1.79
2028	1.08	12.14	0.75	1.84
2029	1.12	12.41	0.77	1.89
2030	1.15	10.98	0.68	1.83
2031	1.18	11.22	0.70	1.88
2032	1.22	11.47	0.71	1.93
2033	1.26	11.72	0.73	1.98
2034	1.29	11.98	0.74	2.04
2035	1.33	12.28	0.76	2.10
2036	1.37	12.55	0.78	2.15
2037	1.41	12.87	0.80	2.21
2038	1.46	13.16	0.82	2.27
2039	1.50	13.49	0.84	2.34
2040	1.55	13.83	0.86	2.40

Notes:
 1. Estimate of PRB coal cost freight on board at the mine site.
 2. Estimate of the cost to deliver fuel to Holcomb Generating Station.
 3. Assumed fuel for the project is Dry Fork Mine PRB coal.

Table 5-3. Summary of Performance and Cost Estimates

	Supercritical PC	Subcritical PC	CFB	IGCC
Performance				
Hot Day Net Plant Output, kW	895,000	895,000	895,000	747,300
Average Day Net Plant Output, kW	903,900	901,900	901,900	800,900
Hot Day Net Plant Heat Rate, Btu/kWh (HHV)	9,089	9,325	9,442	9,014
Average Day Net Plant Heat Rate, Btu/kWh (HHV)	9,000	9,253	9,370	8,962
Annual Average Generation, GWh	7,126	7,111	7,111	5,964
Capital Cost				
EPC Cost, \$Million	1,941	1,888	2,128	2,760
Specific EPC Cost, \$/kW	2,147	2,093	2,359	3,446
Owner's Cost, percent	35	35	35	41
Total Project Cost, \$Million	2,620	2,548	2,873	3,892
Specific Total Project Cost, \$/kW	2,899	2,825	3,185	4,859
O&M Costs				
Fixed Costs, \$/kW	15.79	15.67	16.92	32.03
Nonfuel Variable Costs, \$/MWh	4.17	4.07	4.99	5.80

Without modifying the IGCC case, it is not possible to produce an equivalent case to compare against the PC and CFB cases. The effects of altitude and temperature reduce the output to an extent that the annual average generation is substantially below that expected from Holcomb 2. Whether the shortfall were made up through duct firing or adding another train of gasification and power generation to the IGCC case as defined in this study, the cost of IGCC would be increased to produce an equivalent case.

Table 5-4. Busbar Results			
Case	Description	30 Year Levelized Busbar Cost, ¢/kWh	30 Year Levelized Annual Cost, \$1,000,000
1	Supercritical PC	6.07	432.4
2	Subcritical PC	5.99	426.1
3	CFB	6.63	471.7
4	IGCC	9.73	580.5

Results are based on economic criteria from Table 5-1, fuel forecasts from Table 5-2, and the inputs from Table 5-3.

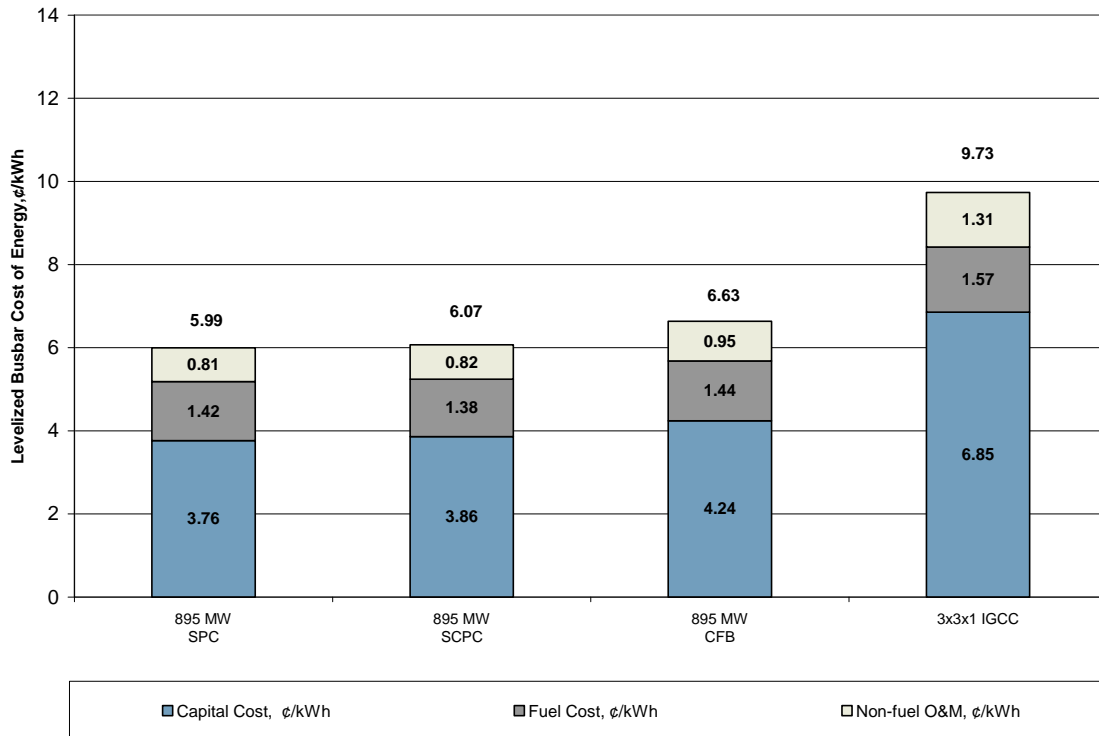


Figure 5-1. Levelized Busbar Cost Comparison

6.0 Conclusions

The economic analysis, as provided in Table 1-3, indicates the lowest cost technologies are the conventional PC and CFB units. The IGCC levelized busbar cost is roughly 50 percent higher than those of the PC and CFB. The costs of emission allowances were not included in the busbar cost analysis.

IGCC is not economically competitive with PC. The limited commercial and operational experience of IGCC would make it a substantial operational and commercial risk as a generating technology for the Expansion Project. IGCC, therefore, is not a practical alternative for the Expansion Project.

The other two technologies evaluated, PC (either super or subcritical) and CFB, are commercially available for consideration for a new 895 MW coal-fired generating facility at Holcomb. The emissions of regulated pollutants from these two technologies are very similar. The most fuel efficient technology is supercritical PC, whose heat rate is approximately three percent better than the subcritical and CFB technologies. CFB is expected to be slightly more expensive, as measured by the levelized busbar cost of power, than PC.

Within the accuracy of the evaluation, the subcritical and supercritical PCs are assumed to be equivalent. Supercritical PC is more efficient than the subcritical PC, which reduces the coal consumption by roughly 2.5 percent which directly reduces the total mass of the flue gas emissions by comparison.