ConocoPhillips E-Gas™ IGCC Plant

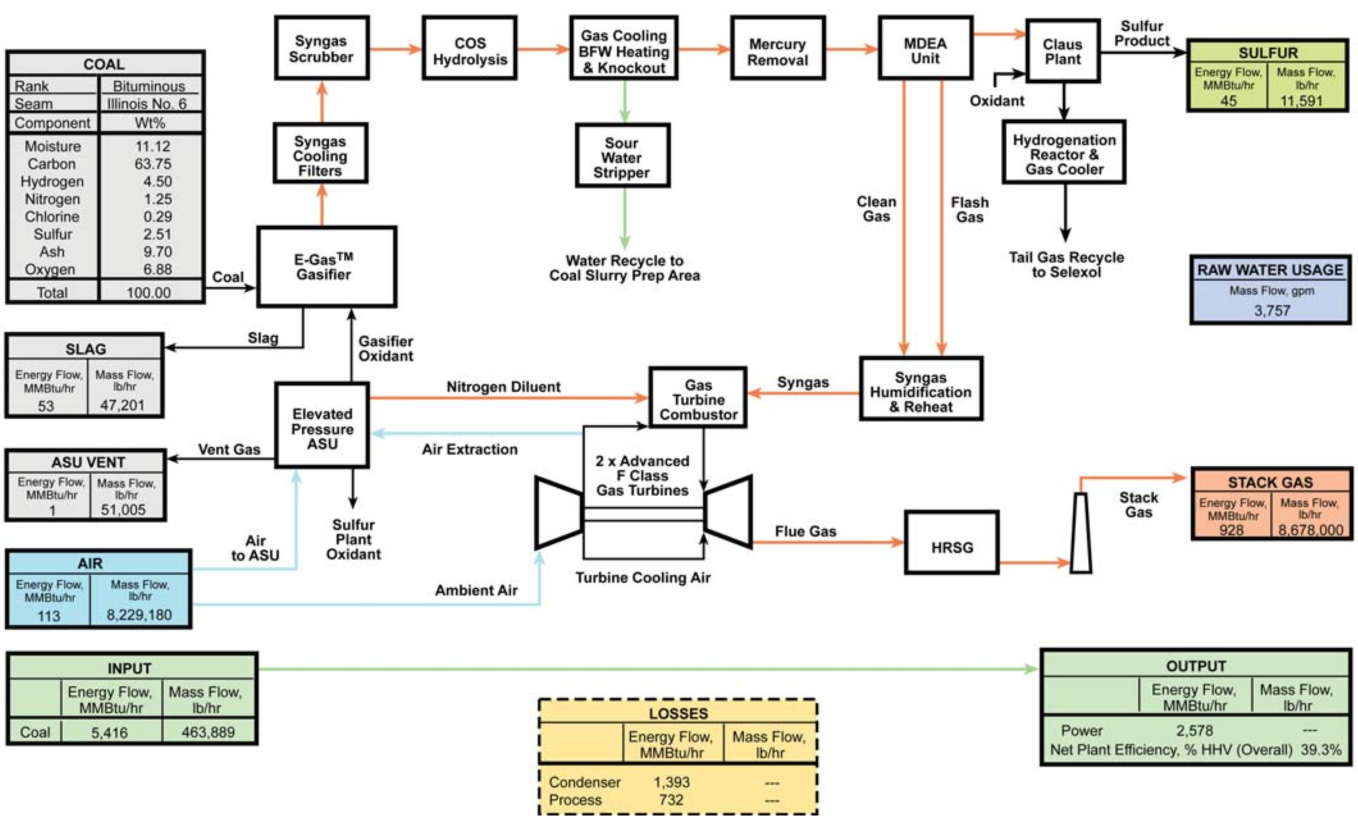
Plant Overview

This analysis is based on a 623 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant, using ConocoPhillip E-Gas™ gasification technology, located at a greenfield site in the midwestern United States. Two pressurized entrained-flow, two-stage gasification trains feed two advanced F-Class combustion turbines. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. The combination process and heat and mass balance diagram for the CoP IGCC plant is shown in Figure 1. The primary fuel is an Illinois No. 6 bituminous coal with a higher heating value (HHV) of 11,666 Btu/lb. The capacity factor (CF) for the plant is 80 percent without sparing of major train components. A summary of plant performance data for the CoP IGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	CoP IGCC
Carbon capture	No
Net power output (kWe)	623,370
Net plant HHV efficiency (%)	39.3
Primary fuel	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	75.3
Total plant cost ($ x 1,000)	$1,080,166

Figure 1. Process Flow Diagram
CoP IGCC



Note: Diagram is provided for general reference of major flows only. For complete flow information, please refer to the final report.

Technical Description

The plant uses an improved version of the CoP gasification technology, which is currently in operation at the PSI Energy Inc. 265 MWe Wabash River IGCC plant near West Terre Haute, IN. All technology selected in the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. A summary of performance for the advanced F-Class combustion turbine for the CoP IGCC plant is presented in Table 2.

Table 2. Advanced Gas Turbine Performance[1]

	Advanced F-Class
Net output, MWe	185
Pressure ratio	18.5
Airflow, kg/s (lb/s)	431 (950)
Firing temperature, °C (°F)	>1,371 (>2,500)

[1]At International Standards Organization conditions firing natural gas. Performance information for syngas firing is not available.

Two gasification trains process a total of 5,567 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the gasifier with a 78/22 split to the primary and secondary stages. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal slurry and oxygen react in the gasifier at about 4.2 MPa (615 psia) at a high temperature (averaging 1,371°C [>2,500°F]), while the portion of slurry injected into the second stage quenches the reaction by means of endothermic gasification reactions.

Gas leaving the gasifier is cooled in a fire-tube syngas cooler producing high-pressure steam. The cooled gas is cleaned of particulate matter (PM) via a cyclone collector followed by a ceramic candle filter. The raw syngas is then further cooled before being cleaned in a spray scrubber to remove remaining particulates and trace components. The syngas goes through a mercury (Hg) removal bed in which 95 percent of the Hg is removed from the syngas with activated carbon. Hydrogen sulfide (H_2S) is removed from the cool, particulate-free gas stream with a refrigerated promoted amine (methyldiethanolamine) solvent. Elemental sulfur is recovered in a Claus bypass-type sulfur recovery unit utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting about one-third of the H_2S in the feed to sulfur dioxide (SO_2), then reacting the H_2S and SO_2 to produce sulfur and water.

A Brayton cycle, fueled by syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined-cycle power generation. Compressed nitrogen from the air separation unit is used in syngas dilution, which aids in minimizing the formation of nitrogen oxides (NOx) during combustion in the gas turbine burner section. Two HRSGs and a steam turbine, operating at 12.4 MPa/566°C/566°C (1,800 psig/1,050°F/1,050°F), form the combined-cycle generation component of the plant. The two cycles are integrated by generation of steam in the HRSG, by feedwater heating in the HRSG, and by heat recovery from the IGCC process (syngas cooler). The plant produces a net output of 623 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 39.3 percent HHV, or a net plant HHV heat rate of 8,681 Btu/kWh.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
HRSG steam turbine, MWe	278.5
Gross power output, MWe	742.5
Auxiliary power requirement, MWe	(119.1)
Net power output, MWe	623.4

Environmental Performance

The environmental specifications for a greenfield IGCC plant are based on the Electric Power Research Institute *CoalFleet User Design Basis for Coal-Based IGCC Plants* specification. Low SO_2 emissions (less than 4 ppmv in the flue gas) are achieved by capture of the sulfur in the Coastal SS Amine acid gas removal (AGR) process, which removes over 99 percent of the sulfur in the fuel gas to less than 30 ppmv. The resulting hydrogen sulfide-rich regeneration gas from the acid gas removal system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides emissions are limited by nitrogen dilution (primarily) and humidification (secondarily) to 15 ppmvd (as nitrogen dioxide at 15 percent O_2). Filterable PM discharge to the atmosphere is limited by a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. Ninety-five percent of the Hg is captured from the syngas by an activated carbon bed.

A summary of the resulting air emissions for the CoP IGCC plant is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	CoP IGCC Without CCS
CO_2	
• tons/year	3,777
• lb/MMBtu	199
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	237
• lb/MMBtu	0.0125
NOx	
• tons/year	1,126
• lb/MMBtu	0.059
PM (filterable)	
• tons/year	135
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

Cost Estimation

Plant size, primary/secondary fuel type, construction time, total plant cost (TPC) basis year, plant CF, plant heat rate, fuel cost, plant book life, and plant in-service date were used to develop capital cost, production cost, and levelized cost-of-electricity (LCOE) estimates. Costs for the plant were based on adjusted vendor-furnished and actual cost data from recent design/build projects. Values for financial assumptions and a cost summary are shown in Table 5.

Project contingencies were added to each case to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Project contingency was 13.3 percent of the CoP IGCC case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 2.5 percent of the CoP IGCC case TPC and have been applied to the estimates as follows:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator – 5 percent on all IGCC cases without CCS.
- Instrumentation and Controls – 5 percent on all IGCC cases.

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, CF is assumed to equal availability and is 80 percent for IGCC cases.

The 623 MWe (net) CoP IGCC plant was projected to have a TPC of $1,733/kWe, resulting in a 20-year LCOE of 75.3 mills/kWh.

Table 5. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions					
Case:	**1x623 MWe net CoP IGCC**				
Plant Size:	623.4	(MWe, net)	Heat Rate:	8,681	(Btu/kWh)
Primary/Secondary Fuel (type):	Illinois #6 Coal		Fuel Cost:	1.80	($/MMBtu)
Construction Duration:	3	(years)	Plant Life:	30	(years)
Total Plant Cost[2] Year:	2007	(January)	Plant in Service:	2010	(January)
Capacity Factor:	80	(%)	Capital Charge Factor:	17.5	(%)
Resulting Capital Investment (Levelized 2007 dollars)					**Mills/kWh**
Total Plant Cost					43.3
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					5.8
Variable Operating Cost					7.3
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					18.8
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					75.3

[1]Costs shown can vary ± 30%.

[2]Total plant cost includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

[3]No credit taken for by-product sales.

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Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.

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