ConocoPhillips E-Gas™ IGCC Plant With Carbon Capture & Sequestration

Plant Overview

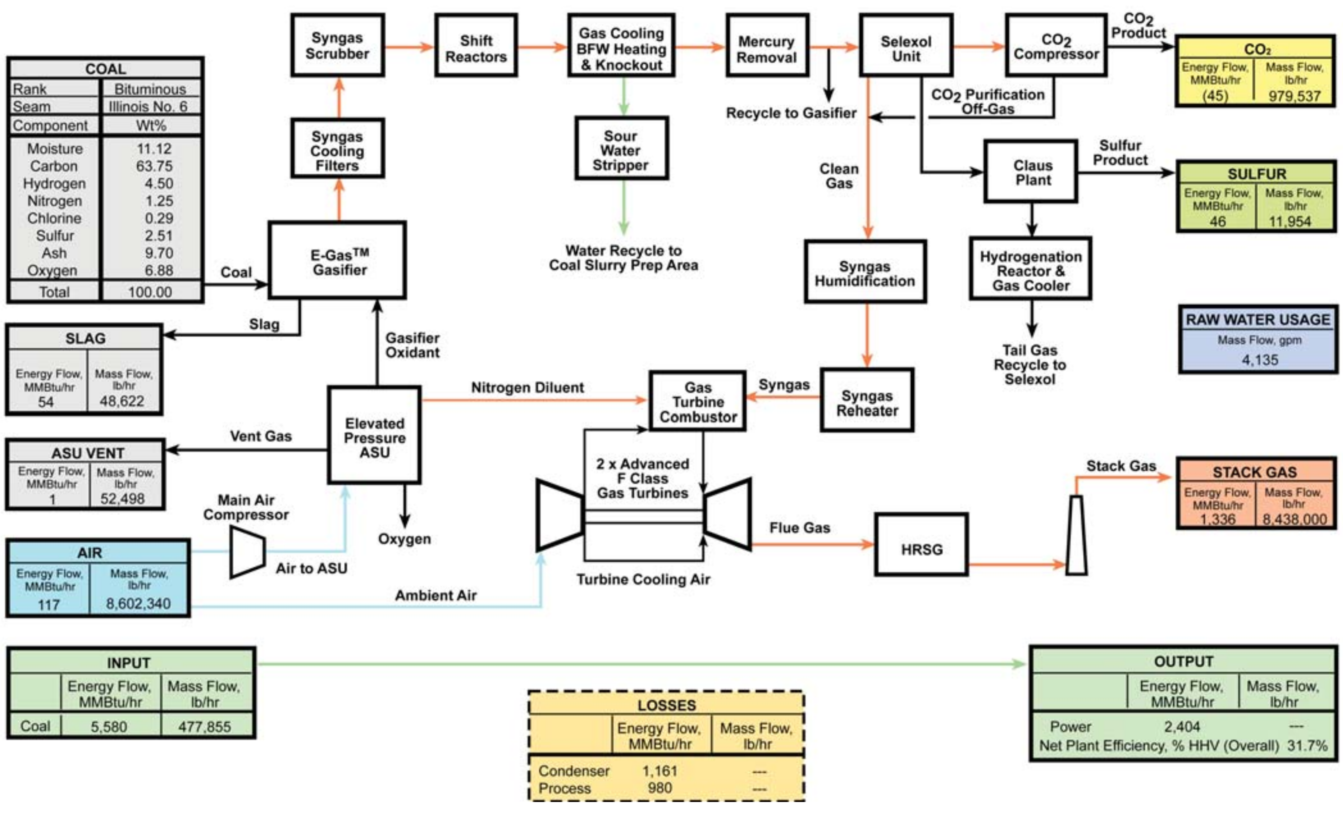
This analysis is based on a 518 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant, using ConocoPhillips E-Gas™ gasification technology, located at a greenfield site in the midwestern United States. The plant utilizes carbon capture and sequestration (CCS). Two pressurized entrained-flow, two-stage gasification trains feed two advanced F-Class combustion turbines. Water-gas-shift (WGS) reactors are used for sour gas shift. Two heat recovery steam generators (HRSGs) and one steam turbine provide additional power. Carbon dioxide (CO_2) is removed with the two-stage Selexol physical solvent process. The combination process and heat and mass balance diagram for the CoP IGCC plant with CCS 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 with CCS is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	CoP IGCC
Carbon capture	Yes
Net power output (kWe)	518,240
Net plant HHV efficiency (%)	31.7
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	105.7
Total plant cost ($ x 1,000)	$1,259,883
Cost of CO_2 avoided[1] ($/ton)	41

[1]The cost of CO_2 avoided is defined as the difference in the 20-year levelized cost-of-electricity between controlled and uncontrolled like cases divided by the difference in CO_2 emissions in kg/MWh.

Figure 1. Process Flow Diagram
CoP IGCC With CCS



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

Technical Description

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.

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 for the plant design is assumed to be available to facilitate a 2010 startup date for a newly constructed plant. However, because certain processes like the combustion turbine operating on a high-hydrogen content syngas and the two-stage Selexol process for CO_2 capture either have no commercial or limited commercial operating experience, a process contingency was included in those cost items. A summary of performance for the advanced F-Class combustion turbines for the CoP IGCC plant with CCS is presented in Table 2.

Two gasification trains process a total of 5,735 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the two-stage 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 O_2 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 Selexol acid gas removal (AGR) system. 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.

To capture CO_2, a WGS reactor containing a series of three shifts with intercooled stages, converts a nominal 98 percent of the carbon monoxide to CO_2. Carbon dioxide is removed from the cool, particulate-free gas stream with Selexol solvent. The double-absorber Selexol process preferentially removes H_2S as a product stream, leaving CO_2 as a separate product stream. The CO_2 is dried and compressed to 15.3 MPa (2,215 psia) for subsequent pipeline transport. The compressed CO_2 is transported via pipeline to a geologic sequestration field for injection into a saline aquifer, which is located within 50 miles of the plant.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
Steam turbine, MWe	229.8
Gross power output, MWe	693.8
Auxiliary power requirement, MWe	(175.6)
Net power output, MWe	518.2

A Brayton cycle, fueled by the syngas, is used in conjunction with a conventional subcritical steam Rankine cycle for combined-cycle power generation. Two HRSGs and a steam turbine, operating at 12.4 MPa/538°C/538°C (1,800 psig/1,000°F/1,000°F) form the combined-cycle generation component of the plant. The two cycles are integrated by generation of steam in the HRSGs, by feedwater heating in the HRSGs, and by heat recovery from the IGCC process (syngas cooler). The plant produces a net output of 518 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 31.7 percent HHV, or a net plant HHV heat rate of 10,757 Btu/kWh.

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 3 ppmv in the flue gas) are achieved by capture of the sulfur in the Selexol AGR process, which removes 99 percent of the sulfur in the fuel gas to less than 22 ppmv. The resulting H_2S-rich regeneration gas from the acid gas removal system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides (NOx) emissions are limited by nitrogen dilution (primarily) and syngas 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. About eighty-eight percent of the CO_2 from the syngas is captured in the AGR system and compressed for shipment and sequestration.

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

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	CoP IGCC With CCS (90%)
CO_2	
• tons/year	460,175
• lb/MMBtu	23.6
• cost of CO_2 avoided ($/ton)	41
SO_2	
• tons/year	167
• lb/MMBtu	0.0085
NOx	
• tons/year	972
• lb/MMBtu	0.050
PM (filterable)	
• tons/year	139
• 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 13.7 percent of the CoP IGCC with CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 4.3 percent of the CoP IGCC with CCS case TPC and have been applied to the estimates as follows:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases.
- Two Stage Selexol – 20 percent on all IGCC CCS cases.
- Mercury Removal – 5 percent on all IGCC cases.
- Combustion Turbine Generator –10 percent on all IGCC cases with 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 calculated cost of transport, storage, and monitoring for CO_2 is $4.40/short ton, which adds 4.1 mills/kWh to the LCOE.

The 518 MWe (net) CoP IGCC plant with CCS was projected to have a TPC of $2,431/kWe, resulting in a 20-year LCOE of 105.7 mills/kWh.

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

Major Assumptions					
Case:	**1x518 MWe net CoP IGCC with CCS**				
Plant Size:	518.2	(MWe, net)	Heat Rate:	10,757	(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					60.7
Resulting Operating Costs (Levelized 2007 dollars)[3]					**Mills/kWh**
Fixed Operating Cost					7.6
Variable Operating Cost					9.9
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu					**Mills/kWh**
					23.3
Resulting Levelized CO_2 Cost (2007 dollars)					**Mills/kWh**
					4.1
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					105.7

[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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