Shell IGCC Plant

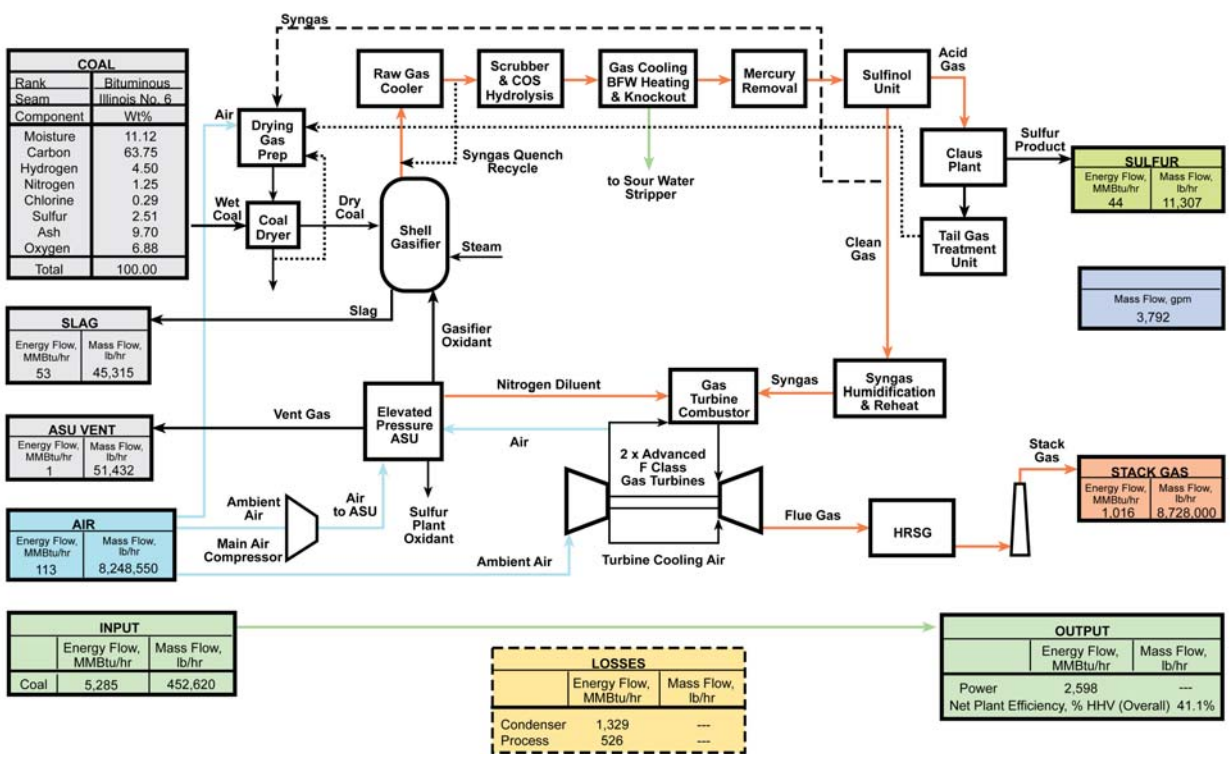
Plant Overview

This analysis is based on a 636 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant using Shell Global Solutions gasification technology located at a greenfield site in the midwestern United States. Two pressurized dry-feed entrained flow 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 Shell 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 Shell IGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	Shell IGCC
Carbon capture	No
Net power output (kWe)	635,850
Net plant HHV efficiency (%)	41.1
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	80.5
Total plant cost ($ x 1,000)	$1,256,810

Figure 1. Process Flow Diagram
Shell 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 the Shell gasification technology. All technology selected in this 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 Shell 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 5,431 tons of coal per day. Dry coal is introduced to the gasifier via lockhoppers. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal reacts with O_2 at about 1,427°C (2,600°F) to produce medium heating value syngas. The syngas is then quenched to around 891°C (1,635°F) by cooled recycled syngas. The syngas passes through a convective cooler and leaves at a temperature near 316°C (600°F). High-pressure saturated steam is generated in the syngas cooler and is joined with the main steam supply. The syngas passes through a cyclone and a raw gas candle filter where a majority of the fine particles are removed. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form.

The raw syngas then enters a scrubber for removal of chlorides and remaining particulate matter (PM). Following the scrubber, the raw syngas is reheated to 177°C (350°F) and fed to a Carbonyl Sulfide (COS) hydrolysis reactor where COS is catalytically converted to Hydrogen Sulfide (H_2S). The syngas is then cooled to about 35°C (95°F) before passing through a carbon bed to remove ninety five percent of the Hg. The Sulfinol process then removes essentially all of the CO_2 along with the H_2S and COS. Elemental sulfur is recovered in a Claus bypass-type sulfur recovery unit utilizing O_2 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 with syngas is used in conjunction with a conventional subcritical steam Rankine cycle. Nitrogen dilution (primarily), syngas humidification (secondarily) and steam injection to a lesser extent aid in minimizing 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 (convective syngas cooler). The plant produces a net output of 636 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 41.1 percent (HHV basis) or a net plant HHV heat rate of 8,304 Btu/kWh.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.0
HRSG steam turbine, MWe	284.0
Gross power output, MWe	748.0
Auxiliary power requirement, MWe	(112.2)
Net power output, MWe	635.9

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 Sulfinol-M AGR process, which removes over 99 percent of the sulfur in the fuel gas. The resulting hydrogen sulfide-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. Nitrogen oxides emissions are limited by syngas humidification and nitrogen dilution in the gas turbine combustor to 15 ppmvd (as nitrogen oxides at 15 percent O_2). Filterable

PM discharge to the atmosphere is limited by the use of 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 Shell IGCC plant is presented in Table 4.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	Shell IGCC Without CCS
CO_2	
• tons/year	3,693,990
• lb/MMBtu	200
• cost of CO_2 avoided ($/ton)	N/A
SO_2	
• tons/year	230
• lb/MMBtu	0.0124
NOx	
• tons/year	1,082
• lb/MMBtu	0.058
PM (filterable)	
• tons/year	131
• 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 as inputs 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 Shell IGCC case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 2.6 percent of the Shell 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 636 MWe (net) Shell IGCC plant was projected to have a total capital requirement of $1,977/kWe, resulting in a 20-year LCOE of 80.5 mills/kWh.

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

Major Assumptions					
Case:	**1x636 MWe net Shell IGCC**				
Plant Size:	635.9	(MWe, net)	Heat Rate:	8,304	(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					49.4
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**
					18.0
Total Levelized Busbar Cost of Power (2007 dollars)					**Mills/kWh**
					80.5

[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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