GE Energy IGCC Plant

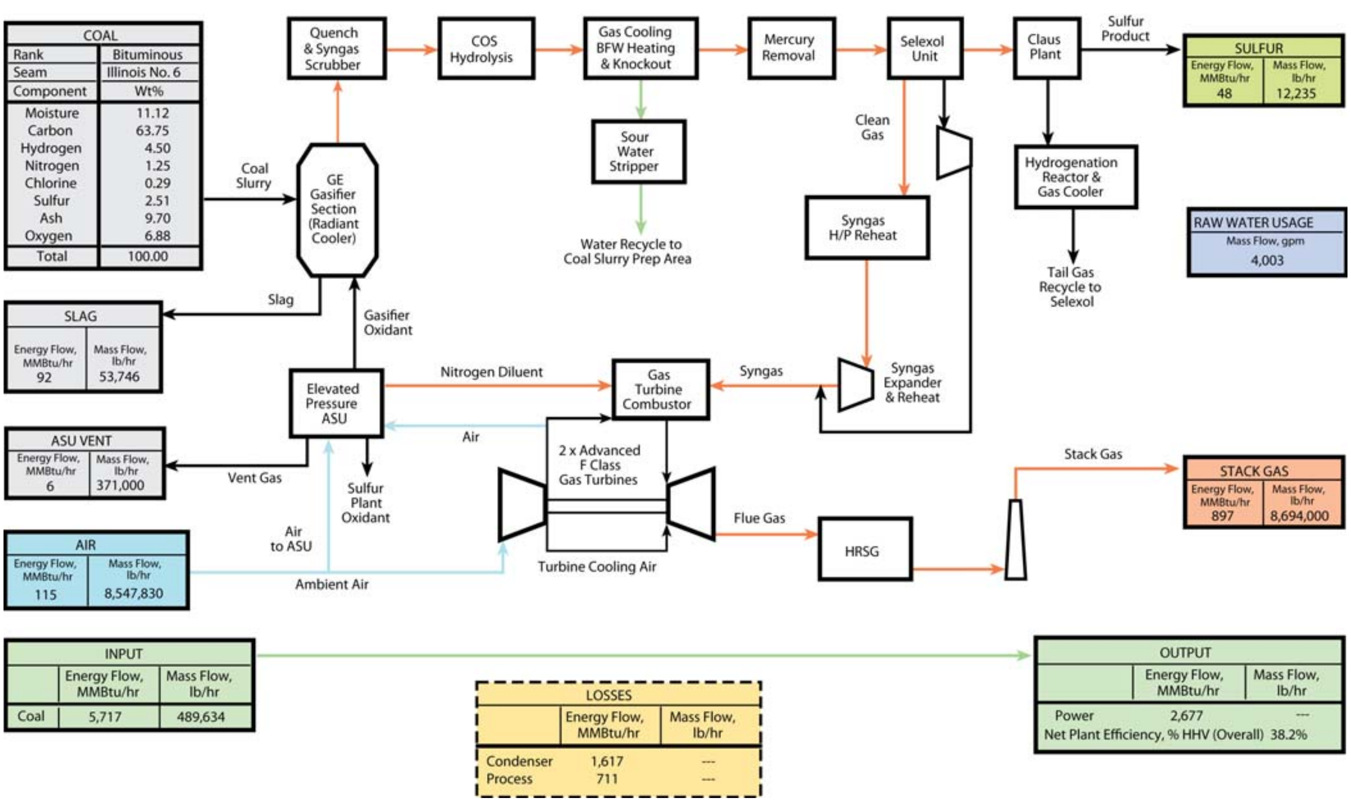
Plant Overview

This analysis is based on a 640 MWe (net power output) Integrated Gasification Combined-Cycle (IGCC) plant using GE Energy (GEE) radiant-only gasification technology, located at a greenfield site in the midwestern United States. The radiant-only configuration consists of a radiant synthesis gas cooler followed by a water quench. Two pressurized, slurry-fed, 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 GEE 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 GEE IGCC plant is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	GEE IGCC
Carbon capture	No
Net power output (kWe)	640,250
Net plant HHV efficiency (%)	38.2
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 80% capacity factor	78.0

Figure 1. Process Flow Diagram
GEE 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 GEE gasification technology (formerly licensed by Chevron Corp. and predecessor company Texaco Inc.), which is currently in operation at the 250 MWe Tampa Electric IGCC plant in Polk County, FL. All technology selected in the plant design is assumed to be available to facilitate a 2010 startup date for anewly constructed plant. A summary of performance for an advanced F-Class combustion turbine for the GEE 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 5,876 tons of coal per day. A slurry (63 percent by weight coal) is transferred from the slurry storage tank to the gasifier with a high-pressure pump. Oxygen (O_2) is produced in a cryogenic air separation unit. The coal slurry and O_2 react in the gasifier at about 5.6 MPa (815 psia) at a high temperature (in excess of 1,316°C [2,400°F]) to produce syngas. Hot syngas and molten solids from the reactor flow downward into a radiant heat exchanger, where the syngas is cooled to 593°C (1,100°F) and the ash solidifies. Raw syngas continues downward into a quench system where most of the particulate matter (PM) is removed and then into the syngas scrubber where most of the remaining entrained solids are removed along with ammonia. Slag captured by the quench system is recovered in a slag recovery unit. The gas goes through a series of additional gas coolers and cleanup processes, including a carbonyl sulfide hydrolysis reactor, a carbon bed for mercury (Hg) removal, and a Selexol-based acid gas removal (AGR) plant.

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 for syngas dilution, which aids in minimizing the formation of nitrogen oxides (NOx) during combustion in the gas turbine burner section. The limiting factor that determines the use of a subcritical steam cycle is the maximum design pressure of 12.4 MPa (1,800 psig), which can be tolerated in the GEE radiant cooler. 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 (radiant syngas cooler). The HRSG/steam turbine cycle is 12.4 MPa/566°C/566°C (1,800 psig/1,050°F/1,050°F). The plant produces a net output of 640 MWe. The summary of plant electrical generation performance is presented in Table 3. This configuration results in a net plant efficiency of 38.2 percent (HHV basis), or a net HHV heat rate of 8,922 Btu/kWh.

Table 3. Plant Electrical Generation

	Electrical Summary
Advanced gas turbine x 2, MWe	464.3
Steam turbine, MWe	298.9
Sweet gas expander, MWe	7.1
Gross power output, MWe	770.3
Auxiliary power requirement, MWe	(130.1)
Net power output, MWe	640.2

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 sulfur dioxide (SO_2) emissions (less than 4 ppmv in the flue gas) are achieved by capture of the sulfur in the Selexol 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 nitrogen dilution in the gas turbine combustor to 15 ppmvd (as nitrogen oxide at 15 percent O_2). Filterable PM discharge to the atmosphere is limited by the use of the syngas quench 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 GEE IGCC plant is presented in Table 4.

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 GEE 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 GEE IGCC case TPC and have been applied to the estimates as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases.
- 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.

Table 4. Air Emissions Summary @ 80% Capacity Factor

Pollutant	GEE IGCC Without CSS
CO_2	
• tons/year	3,937,728
• lb/MMBtu	197
• cost of CO_2 avoided	N/A
SO_2	
• tons/year	254
• lb/MMBtu	0.0127
NOx	
• tons/year	1,096
• lb/MMBtu	0.055
PM (filterable)	
• tons/year	142
• lb/MMBtu	0.0071
Hg	
• tons/year	0.011
• lb/TBtu	0.571

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 640 MWe (net) GEE IGCC plant was projected to have a TPC of $1,813/kWe, resulting in a 20-year LCOE of 78 mills/kWh.

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

Major Assumptions						
Case:	**1x640 MWe net GEE IGCC**					
Plant Size:	640.3	(MWe, net)	Heat Rate:	8,922	(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						45.3
Resulting Operating Costs (Levelized 2007 dollars)[3]						**Mills/kWh**
Fixed Operating Cost						5.8
Variable Operating Cost						7.5
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu						**Mills/kWh**
						19.4
Total Levelized Busbar Cost of Power (2007 dollars)						**Mills/kWh**
						78.0

[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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