Subcritical Pulverized Bituminous Coal Plant With Carbon Capture & Sequestration

Plant Overview

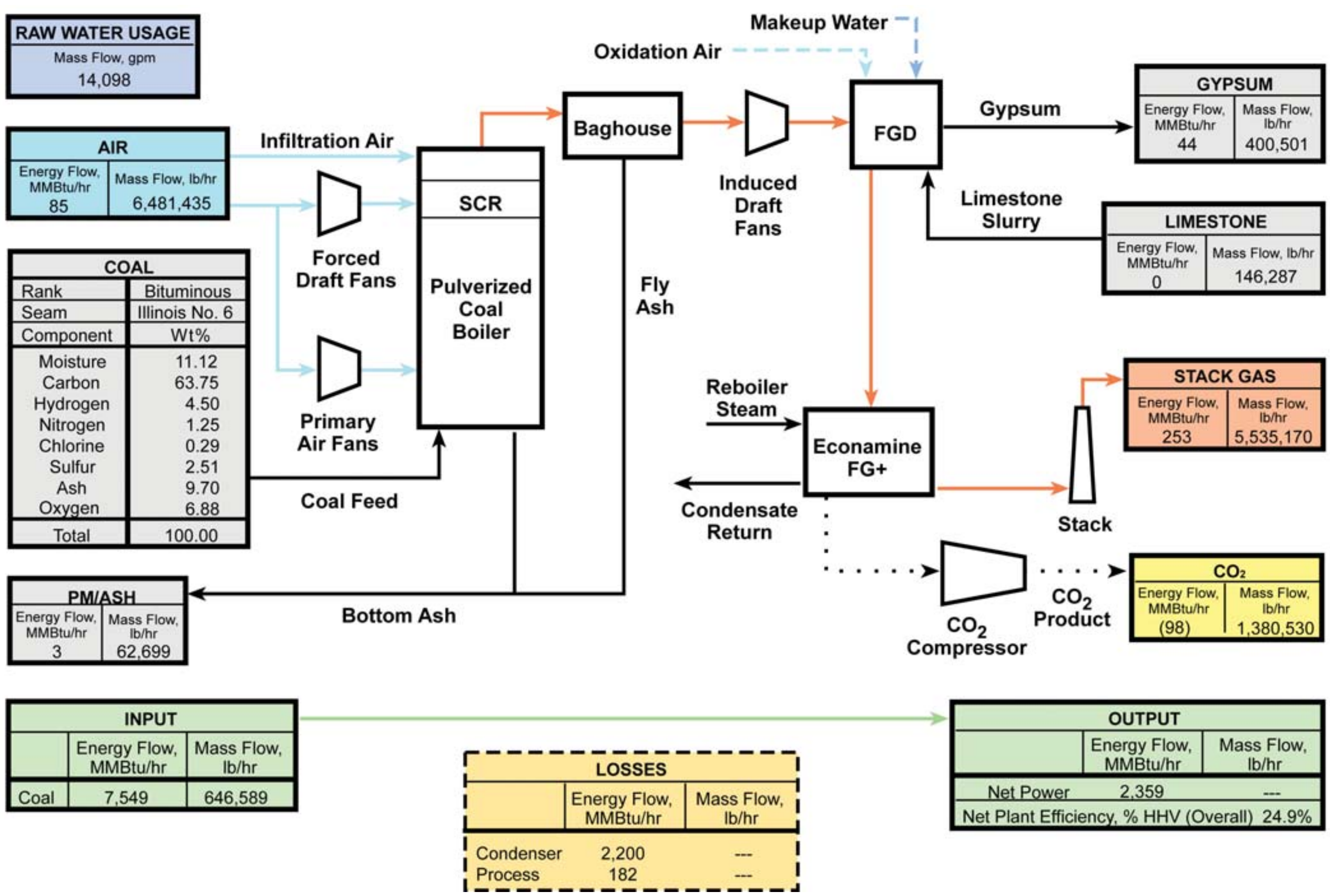
This analysis is based on a 550 MWe (net power output) subcritical bituminous pulverized coal (PC) plant located at a greenfield site in the midwestern United States. This plant captures carbon dioxide (CO_2) to be sequestered and is designed to meet Best Available Control Technology (BACT) emission limits. The plant is a single-train design. The combination process, heat, and mass balance diagram for the subcritical PC plant with carbon capture and sequestration (CCS) case 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 85 percent without sparing of major train components. A summary of plant performance data for the subcritical PC plant with CCS is presented in Table 1.

Table 1. Plant Performance Summary

Plant Type	PC Subcritical
Carbon capture	Yes
Net power output (kWe)	549,613
Net plant HHV efficiency (%)	24.9
Primary fuel (type)	Illinois No. 6 coal
Levelized cost-of-electricity (mills/kWh) @ 85% capacity factor	118.8
Total plant cost ($ x 1,000)	$1,591,277
Cost of CO_2 avoided[1] ($/ton)	68

[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
Subcritical Pulverized Coal Unit 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

The analysis for the subcritical PC plant with CCS is based on a commercially available dry-bottom, wall-fired boiler equipped with low-nitrogen oxides (NOx) burners (LNBs) and over-fire air (OFA). The unit is a balanced-draft, natural-circulation design equipped with a superheater, reheater, economizer, and air preheater. Hot flue gas (FG) exiting the boiler is treated by a selective catalytic reduction (SCR) unit for NOx removal, a baghouse for particulate matter (PM) removal, and a limestone-based scrubber for sulfur dioxide (SO_2) control and co-removal of mercury (Hg). This plant utilizes a conventional steam turbine for power generation. The Rankine cycle is based on a single reheat system with steam conditions of 16.5 MPa/566°C/566°C (2,400 psig/ 1,050°F/1,050°F).

This subcritical PC plant with CCS is equipped with the Fluor Econamine FG Plus™ technology for carbon capture. Flue gas exiting the scrubber system is directed to the Econamine FG Plus™ process, where CO_2 is absorbed in a monethanolamine-based solvent. A booster blower is required to overcome the process pressure drop. Carbon dioxide recovered in the Econamine FG Plus™ process is dried, compressed, and delivered to the plant fence line at 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.

Achieving a nominal 550 MWe net output with this plant configuration results in an HHV thermal input requirement of 2,210,668 kWt (7,543 MMBtu/hr basis). This thermal input is achieved by burning coal at a rate of 646,589 lb/hr, which yields an HHV net plant heat rate of 13,724 Btu/kWh (net plant efficiency of 24.9 percent). The gross power output of 680 MWe is produced from the steam turbine generator. With an auxiliary power requirement of 130 MWe, the net plant output is 550 MWe. The Econamine FG Plus™ process imposes a significant auxiliary power load on the system, which requires this case to have a higher gross output, as compared with the subcritical without CCS case, to maintain the same 550 MWe net output.

Environmental Performance

This study assumes the use of BACT to meet the emission requirements of the 2006 New Source Performance Standard for criteria pollutants.

The subcritical PC plant with CCS has an emission control strategy consisting of LNBs with OFA and SCR for NOx control, a pulse jet fabric filter for PM control, and a wet-limestone, forced-oxidation scrubber for SO_2 control. After NOx emissions are initially controlled through the use of LNBs and OFA, an SCR unit is used to further reduce the NOx concentration by 86 percent. Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent. The wet-limestone, forced-oxidation scrubber achieves a 98 percent removal of SO_2. A polishing scrubber included as part of the Econamine FG Plus™ process further reduces the SO_2 concentration to less than 10 ppmv. The balance of the SO_2 is removed in the Econamine absorber resulting in negligible SO_2 emissions. The byproduct from the wet-limestone scrubber calcium sulfate, is dewatered and stored onsite. The wallboard-grade material potentially can be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit is taken. The combination of SCR, a fabric filter and wet scrubber also

Table 2. Air Emissions Summary @ 85% Capacity Factor

Pollutant	PC Subcritical With CCS (90%)
CO_2	
• tons/year	569,524
• lb/MMBtu	20.3
• cost of CO_2 avoided ($/ton)	68
SO_2	
• tons/year	Negligible
• lb/MMBtu	Negligible
NOx	
• tons/year	1,966
• lb/MMBtu	0.070
PM	
• tons/year	365
• lb/MMBtu	0.013
Hg	
• tons/year	0.032
• lb/TBtu	1.14

provides co-benefit Hg capture at an assumed 90 percent of the inlet value. After leaving the Econamine FG Plus™ process, the flue gas is vented through the plant stack.

A summary of the resulting air emissions is presented in Table 2.

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 3.

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 12.5 percent of the subcritical PC CCS case TPC.

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies represent 3.6 percent of the subcritical PC CCS case TPC and have been applied to the estimates as follows:

- CO_2 Removal System – 20 percent on all PC CCS cases.
- Instrumentation and Controls – 5 percent on the PC CCS 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 85 percent for PC cases.

For the PC cases that feature CCS, capital and operating costs were estimated for transporting CO_2 to an underground storage area, associated storage maintenance, and for monitoring beyond the expected life of the plant. These costs were then levelized over a 20-year period.

The calculated cost of transport, storage, and monitoring for CO_2 is $3.40/short ton, which adds 4.3 mills/kWh to the LCOE.

The 550 (net) MWe subcritical PC plant with CCS was projected to have a TPC of $2,888/kWe, resulting in a 20-year levelized COE of 118.8 mills/kWh.

Table 3. Major Financial Assumptions and Resulting Cost Summary[1]

Major Assumptions						
Case:	**1x550 MWe net Subcritical PC with CCS**					
Plant Size:	549.6	(MWe, net)	Heat Rate:	13,724	(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:	85	(%)	Capital Charge Factor:	17.5	(%)	
Resulting Capital Investment (Levelized 2007 dollars)						**Mills/kWh**
Total Plant Cost						68.0
Resulting Operating Costs (Levelized 2007 dollars)[3]						**Mills/kWh**
Fixed Operating Cost						5.8
Variable Operating Cost						10.8
Resulting Fuel Cost (Levelized 2007 dollars) @ $1.80 / MMBtu						**Mills/kWh**
						29.8
Resulting Levelized CO_2 Cost (2007 dollars)						**Mills/kWh**
						4.3
Total Levelized Busbar Cost of Power (2007 dollars)						**Mills/kWh**
						118.8

[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.

Contacts

Julianne M. Klara
Senior Analyst
National Energy Technology Laboratory
626 Cochrans Mill Road
P.O. Box 10940
Pittsburgh, PA 15236
412-386-6089
julianne.klara@netl.doe.gov

John G. Wimer
Systems Analysis Team Lead
National Energy Technology Laboratory
3610 Collins Ferry Road
P. O. Box 880
Morgantown, WV 26507
304-285-4124
john.wimer@netl.doe.gov

Reference: Cost and Performance Baseline for Fossil Energy Plants, Vol. 1, DOE/NETL-2007/1281, May 2007.
B_PC_SUB_CCS_051507